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Draft

1991 NORTHWEST CONSERVATION and ELECTRIC POWER PLAN

VOLUME II

Group 5

Includes:

Chapter 8: Generating Resources

Chapter 9: Accounting for Environmental Effects in Resource Planning

Chapter 16: Confirmation Agendas for Geothermal, Ocean, Wind and Solar Resources

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To Interested Parties:

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CHAPTER 8

GENERATING RESOURCES

Chapter 8
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Introduction

Because of its geographical diversity, the Pacific Northwest is endowed with a wide variety of resources that could help meet future energy needs. This chapter describes these resources and assesses the prospects for their development. All potentially available resources are examined. Those whose development appears to be technically, economically, environmentally and institutionally feasible within the 20-year planning period are considered further for the resource portfolio. Technical, environmental and legal issues associated with the development of these resources are described. Resolving these issues is essential if these resources are to be available to meet future loads. Many of the actions in the Action Plan address the resource development issues described in this chapter.

In addition, another issue often arises from specific technical, environmental and legal resource development issues, and sometimes persists beyond resolution of these issues. This is the issue of public acceptance. While public acceptance problems are often associated with nuclear, coal, municipal solid waste, hydropower and transmission projects, it is possible that public acceptance may present a barrier to the development of any of the new resources considered in this plan.

This plan approaches the issue of public acceptance by identifying the concrete technical, environmental and legal issues associated with each resource, and by recommending actions to resolve these issues. But, the Council realistically recognizes that public acceptance may constrain development of resources. The Council is addressing this risk through actions intended to make a wide diversity of resources available for development.

Resources Assessed in this Chapter

Table 8-1 summarizes the cost and availability of resources assessed in this chapter.

In this plan, emphasis is placed on the assessment of renewable resources and cogeneration. These resources are given high priority in the Northwest Power Act because their development typically results in fewer adverse environmental impacts than conventional thermal resources. Moreover, renewable and conservation resources often have other desirable characteristics such as relatively short development lead times and small module size. A large proportion of the costs of these resources are fixed, potentially lending long-term stability to power system costs.

Table 8-1
Generating Resource Cost and Availability Summary
(1988 Dollars)

Resource	Quantity Available (MWa)	Quantity Promising (MWa)	Cost Range (c/kWh)[a]	Cost Average (c/kWh)	Earliest Service[b]	Comment
Biomass (Stand-alone Power Plants)						
Misc. Wood and Ag. Residue	90	--	7.6-15.1	12.2	1996	Resource uncertainty: 0 to 430 MW
Sewage Treatment/Landfill Gas	n/est	n/est	n/est	n/est	n/est	Small resource potential
Coal						
Eastern Montana (Colstrip)	1,704	--	n/app	7.7	2000	Delivered to grid
Eastern Washington (Creston)	745	--	n/app	8.9	1997	Delivered to grid
Eastern Oregon (Boardman)	745	--	n/app	9.3	2000	Delivered to grid
Northern Nevada (Thousand Springs)	716	--	n/app	9.6	1997	Delivered to grid
Western Washington/Oregon (Centralia)	750	--	n/app	9.6	2000	Delivered to grid
Cogeneration						
Biomass Fuels[c]	480	--	<5.4-10.7	6.8	1994	Resource uncertainty: 0 to 1,570 MW
Natural Gas Fuels[d]	1,720	--	<5.4-10.7	9.6	1995	Resource uncertainty: 210 to 3,540 MW
Generating Plant Efficiency Improvements						
Hydropower	110	150	0.2-2.2	--	1994	Full recovery over 20 years
Nuclear	n/est	9	n/est	n/est	n/est	WNP-2 turbine rotor replacement
Fossil	n/est	n/est	n/est	n/est	n/est	Possibly 100 MWa
Geothermal						
Basin and Range Sites	350	--	--	7.4	1994	
Cascades Sites	--	1,000	--	6.8	1998	
Hydropower						
New Hydropower	410[e]	--	<2.2-11.8	7.3	1993	Resource uncertainty: 185 to 900 MW
Natural Gas/Fuel Oil						
Combined-cycle Combustion Turbines	2,500	--	6.0-8.5[f]	--	1995	Displaced by nonfirm hydropower

Table 8-1 (cont.)
Summary: Generating Resource Cost and Availability
(1988 Dollars)

Resource	Quantity Available (MWa)	Quantity Promising (MWa)	Cost Range (c/kWh)[a]	Cost Average (c/kWh)	Earliest Service[b]	Comment
Municipal Solid Waste	30	--	g	g	1996	Resource uncertainty: 0 to 100 MWa
Nuclear						
WNP-1	818	--	n/app	8.0	1999	
WNP-3	868	--	n/app	7.3	1999	
Advanced Reactors	0	--	n/est	n/est	2000+	Uncertain commercial availability
Ocean						
Wave Power	0	h	--	16	--	Immature technology
Marine Biomass	0	--	--	--	--	Immature technology
Salinity Gradient	0	--	--	--	--	Technology not available
Ocean Current	0	--	--	--	--	Immature technology
Tidal Power	0	0	n/est	~60	--	Poor resource in PNW
Ocean Thermal	0	0	--	--	--	No resource potential in PNW
Solar						
Photovoltaic	0	n/est	n/est	30[f]	1994	
Parabolic Trough	0	n/est	n/est	9.6	1994	LUZ - solar only
Parabolic Trough w/gas backup	0	n/est	n/est	20	1994	LUZ - gas hybrid
Parabolic Trough w/CCCT	0	n/est	n/est	14	1996	LUZ/CCCT hybrid
Transmission and Distribution Loss Reduction						
Conservation Voltage Regulation	100	--	0.1-1.5	--	1991	
Efficient Dist. Transformers	70	--	0.7-9.6	--	1992	Full recovery over 20 to 30 years
Reconductoring	95	--	3.2-14.6	--	1992	Full recovery over 20 to 30 years
Federal Projects	35	--	4.0-10	--	1994	
WIND						
Wind	400	--	7.4-13.0	9.9	1995	
Wind	--	1,000	--	9.3	1999	

Table 8-1 (cont.)
Generating Resource Cost and Availability Summary
(1988 Dollars)

NOTES:

a Costs are levelized nominal for hypothetical 1988 commercial service, normalized to a 40-year operating service life. Interconnection costs are included.
b Earliest inservice dates are for new projects.
c Pulp and paper and wood products sectors.
d Petrochemical, hospital and institutional sectors.
e Firm energy. Total average energy is 510 megawatts.
f Costs are approximate.
g The cost of electricity from a municipal solid waste plant is strongly affected by the fee received for taking fuel (waste), which in turn is a function of the cost of alternative disposal methods. Because the cost of producing electricity may be low relative to that of other resources, the price of electricity from a municipal solid waste plant is determined by the avoided resource cost at the time a plant comes into service.
h Several hundred megawatts of potential.
i A conservation resource; costs do not include conservation credit.

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Significant development of cogeneration and renewable resources has occurred in recent years in California, which unlike the Northwest, has had a need for new generating resources. This development activity has provided useful information for updating earlier estimates of the availability of these resources in the Northwest. As a result of this new information, and a focusing of effort on these resources, the assessments of cogeneration, biomass, geothermal, ocean, solar and wind resources appearing in this plan are in much greater detail than those appearing in previous power plans.

A second area of significant effort is the assessment of new coal resources. Alhough there are growing uncertainties regarding the environmental desirability of new coal plants, new coal-fired power plants may be required if high load growth continues and other, more environmentally desirable, resources fail to develop. The cost of new coal plants also remains important in identifying other resources that may be cost-effective.

In earlier plans, the cost of energy from new coal-fired power plants was based on a single representative plant located at Boardman, Oregon. This plan introduces what is believed to be a more realistic assessment of the future cost of energy from new coal-fired power plants by considering additional factors, such as alternative plant sites, the cost and losses of transmission interconnection, coal price uncertainty and the additional cost of emission controls exceeding current federal standards.

Less effort has been directed to reassessing new hydropower resources and the representative cost and operating characteristics of combustion turbines, combustion turbine combined-cycle plants and the various coal-fired technologies. These were assessed in depth in the 1989 Supplement to the 1986 Power Plan. Because the cost and performance estimates for these technologies remain valid, this plan generally relies on the findings of the 1989 supplement.

Resource Cost Estimates

The estimates of resource costs that appear in this plan are intended to include the full economic costs of constructing, operating and decommissioning power plants. These include, as appropriate, the cost components listed in Table 8-2.

Cost of Energy Estimates

Levelized energy costs are calculated for most resources assessed in this chapter. These costs (see Table 8-1) are intended to reflect the intrinsic economic costs of producing energy from these resources, thereby facilitating comparisons of these resources on their own merits. The apparent cost of energy from otherwise similar projects can be affected significantly by factors not intrinsic to the resources. These factors include the type of developer and the project service date. When comparing costs in nominal dollars, it also is necessary to assess costs over a common service lifetime.

New power plants might be constructed by independent developers, investor-owned utilities or consumer-owned utilities. The costs of capital and other factors affecting plant financing and tax obligations differ for these various types of developers (see Volume II, Chapter 13). Because of this, the cost of energy from plants that are physically identical, but constructed by different types of developers, will vary. For example, a consumer-owned utility such as a public utility district will not be subject to federal income taxes, whereas an independent (non-utility) resource developer normally will have to pay federal income taxes on the return on the investment.

In addition to bringing different financial characteristics to a project, different types of developers will bring different levels of investment risk from the ratepayer's perspective. For example, the ratepayers of a consumer-owned utility acting as a project developer assume the responsibility and risks associated with construction and operation of the project. Alternatively, if the utility chooses to purchase power from an independent developer, many of these responsibilities and risks are assumed by the independent project developer. Of course, the independent developer will require a greater return on his equity investment as compensation for his assumption of the additional risk.

Financial assumptions representative of investor-owned utilities generally were used to develop the reference energy costs appearing in this chapter. This was done primarily to achieve parity of investment risk among resources. Additionally, investor-owned utility financial assumptions produce energy costs midway between those resulting from the use of typical independent developer financing and those resulting from typical municipal financing, other factors being equal, and thus better represent "typical" resource costs.

Exceptions to the use of investor-owned utility financial assumptions are the analysis of the use of combustion turbines for backing up nonfirm hydropower and the analysis of cogeneration potential. The nonfirm strategies analysis uses melded financial assumptions proportional to the utility owners of nonfirm hydropower. The combustion turbine analysis was based on a model that uses financial assumptions representative of independent developers.

Table 8-2
Economic Costs Considered in the Resource Assessments

1. Acquisition program administration costs
2. Siting and licensing costs, including:
   - Land options
   - Easements and right-of-way acquisition
   - Owner's costs during siting and licensing
   - Permits and licenses
   - Geotechnical surveys
   - Environmental impact statement
3. Construction costs, including:
   - Land acquisition
   - Site utilities and services
   - Direct construction costs
   - Construction management and engineering
   - Contingency allowance
   - Owner's costs during construction
   - Switchyard
   - Transmission interconnect to grid
   - Spare parts inventory
   - Royalties
   - Socioeconomic impact mitigation
   - Preproduction (start-up) costs
   - Sales tax (where applicable)
   - Interest during construction
4. Fuel costs, including:
   - Fixed fuel delivery costs
   - Fuel inventory
   - Fuel commodity costs
5. Operating and maintenance costs, including:
   - Fixed operating and maintenance costs
   - Variable operating and maintenance costs
   - Consumables
   - By-product credit
   - Post-operational capital replacement (for operating through the expected service life)
   - Property taxes
   - Insurance
   - Generating taxes and gross revenue taxes
6. Decommissioning costs

Representative financial and tax characteristics of investor-owned utilities and other types of resource developers are described in Volume II, Chapter 13.

Other factors affecting the cost of energy from a power plant include the plant's in-service date and service life. Energy costs are sensitive to the date of first service because of price escalation and general inflation. Whether expressed in real or nominal dollars, energy costs are sensitive to real price escalation. The cost of energy from a plant using a fuel whose price is increasing in real (fixed-year) dollars over time, for example, will be greater if the plant sees service in 2000, than if the plant goes online in 1995. Levelized energy costs expressed in nominal dollars (the convention in this plan) are further affected by general inflation. In nominal dollars, in an inflationary environment, the cost of energy from a plant coming into service in 2000 generally will be greater than for the same plant coming into service in 1995.

The nominal reference energy costs appearing in this chapter are based on a common 1988 in-service date. Actual projects will, of course, see service at later and varied dates. Other factors being equal, levelized energy costs for actual projects having later start-up dates generally will be greater than the costs appearing in this chapter because of the effects of price escalation and general inflation.

Although energy costs expressed in real dollars are insensitive to project service life, nominal dollar estimates must be normalized to a common service period to account for the replacement costs needed for resources anticipated to have shorter service lives. The nominal reference costs appearing in this chapter are normalized to a common 40-year service period.

The electrical use forecasts and the resource portfolio analysis described in Volume II, Chapters 6 and 10, respectively, account for the cost effects of service date and service life.

Content of the Following Sections

The first part of each of the following sections includes an introduction to a resource, followed by descriptions of the technologies available for its use and general issues associated with its development. The second part of each section consists of an assessment of the potential for the future development of the resource in the Northwest. The availability and cost-effectiveness of the resource is assessed, and specific constraints to development in the Northwest are identified. The sections conclude with a table of the planning assumptions used for subsequent portfolio analysis of the resource.

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Biomass[1]

Biomass fuels are defined as any organic matter that is available on a renewable basis. This includes forest residues, wood product (mill) residues, agricultural field residues and processing waste products, agricultural and forest crops grown for fuel and municipal solid wastes. The physical characteristics of these materials vary widely depending on the source. They may have a high moisture content, as in animal wastes or low moisture content, as in plastics in municipal solid waste. Their heating value generally is related to their moisture content, but biomass energy density generally is low compared to coal or petroleum fuels. Biomass fuels typically are low in sulfur and nitrogen, and have minimal atmospheric impact when burned correctly.

Biomass fuels (which originate generally as solids) can be converted to liquid or gaseous fuels, or they can be burned directly to generate steam. When used to generate electricity, solid biomass fuels generally are burned in steam-electric power plants. Conversion of biomass fuels to liquid or gaseous form broadens the range of conversion technologies that may be used to generate electricity. In addition to steam-electric power plants, diesel-electric power plants, combustion-turbine plants and fuel cells may be used to generate electricity from liquified or gasified biomass.

Largely because of the abundance of Northwest forest resources, biomass currently plays an important role in meeting the region's total energy needs. Most of the current contribution of biomass to the Northwest energy supply is from the direct use of biomass for industrial process heating and residential space heating. A lesser role is played by biomass in the generation of electric power.

The total capacity of biomass-fired power plants in the region selling power to electrical utilities is about 470 megawatts, somewhat over 1 percent of total regional capacity. Three utility plants using wood residues are in operation in the region. These include the Washington Water Power Kettle Falls Generating Station, the Eugene Water and Electric Board Willamette Steam Plant and the Tacoma Department of Public Utilities Steam Plant 2 (designed to accept coal and refuse-derived fuel, in addition to wood waste). The total capacity of these plants is 126 megawatts, and they produce an average 92 megawatts of energy.

There are about 25 additional non-utility generating plants in the Northwest using biomass as a primary fuel which contract to sell power to electrical utilities.

1./ Much of the background information and analysis in this section was taken from the paper *Assessment of Biomass Resources for Electric Generation in the Pacific Northwest.* This paper was prepared for the Council by Dr. James D. Kerstetter of the Washington State Energy Office. It was released as Council Staff Issue Paper 89-41 *Biomass Resources*, October 16, 1989. The Northwest Power Planning Council appreciates the assistance that it has received from the Washington State Energy Office in support of the assessment of biomass resources for this plan.

Several plants have been developed by independent power producers, but most are cogeneration plants in the lumber and wood products industry and the pulp and paper industry. Many of the latter plants burn spent pulping "liquor." Although records are uncertain, about 380 megawatts of capacity from non-utility biomass-fired power plants are contracted to Northwest electric utilities. The energy production of these plants varies year-to-year depending upon fuel cost and availability, and the owner's needs for electricity and steam.

The Council did not consider a specific amount of biomass for the 1986 power plan resource portfolio. Citing uncertainties regarding the cost and availability of this resource, the Council called for studies, through the Pacific Northwest Regional Bioenergy Program, to improve understanding of the cost and availability of biomass fuels. For this power plan, the Washington State Energy Office agreed to prepare an estimate of the future availability and cost of biomass resources for electric power generation. That study, prepared by Dr. James D. Kerstetter (Kerstetter, 1989), assessed the future availability and cost of the principal biomass residues available for future use in the Pacific Northwest, including forest residues, wood products residues, agricultural residues and municipal solid waste. This section summarizes the findings of the Kerstetter paper and discusses the Council's conclusions regarding the cost and availability of biomass. This section also assesses the potential for new stand-alone electric power generation using biomass fuels (except for municipal solid waste discussed later in this chapter). A portion of the biomass fuel supply will be used for new cogeneration applications. An assessment of the potential for biomass-fired cogeneration is contained in this chapter's section on cogeneration.

Technology

A wide variety of technologies can be used to generate electricity from biomass fuels. Most applications involve a fuel preparation step followed by combustion in a thermal-electric generating plant. Fuel preparation may be simple chipping of forest residue, or complex chemical or biological processes that convert the normally solid biomass residues into gaseous or liquid fuels. Most biomass residues originate as solids. At present, solid biomass fuels must be burned in direct-fired steam-electric plants of typically low efficiency. However, pressurized fluidized-bed power plants under development also may allow solid biomass to be used directly in high-efficiency combined-cycle plants. Conversion to gaseous or liquid forms permits solid biomass residues to be used for a much broader range of generating plant types. Gasified or liquified biomass may be used to fuel combustion turbines, internal combustion reciprocating engines and fuel cells, in addition to conventional steam-electric plants. Gaseous or liquid fuels can be stored more readily than the original residue. This may be useful in smoothing out the seasonal fluctuations in supply of many biomass residues.

Direct-firing of Biomass

Most generation of electricity using biomass is accomplished in direct-fired steam-electric power plants. Prior to firing, the residue typically is reduced to a uniform particle size by chipping or grinding. Additional preparation steps may include drying and compression into pellets, briquets, logs or cubes to facilitate transportation, storage or firing.

A biomass-fired steam-electric power plant consists of a furnace and steam-generator, a steam turbine-electric generator and a condenser cooling system. The furnace may use either conventional stoker firing or may use the newer fluidized bed for improved combustion control. Steam from the steam generator drives a turbine generator. Exhaust steam from the turbine is condensed and returned to the steam generator. A cooling system, generally employing a cooling tower, is used for condenser cooling. Plants burning wood or agricultural residues use cyclones, baghouses or precipitators to remove particulates from the flue gas. Additional emission control devises generally are not necessary. Direct-fired steam-electric plants may be stand-alone, or may cogenerate steam or hot water for industrial processes or space heating.

Biomass-fired steam-electric generating plants generally operate at low to moderate efficiency (approximately 17 to 25 percent), compared to the efficiencies commonly attainable with fossil-fuel steam plants. A developing technology that eventually may improve the efficiency to generate electricity using solid biomass fuels is the pressurized fluidized-bed power plant. This design allows solid fuels to be used to directly fire a combined-cycle power plant, resulting in greatly improved efficiency. In a pressurized fluidized-bed plant, the fuel is burned in a closed furnace. The hot, pressurized combustion gasses are cleaned, then directed to a gas turbine driving an electric generator. Exhausting from the gas turbine, the still-hot gasses pass through a heat-recovery steam generator where steam is generated to drive a turbine generator, as in a conventional steam-electric plant.

Biomass Gasification

Among the processes that may be used to convert biomass residues to gaseous fuels are anaerobic digestion and partial combustion. Anaerobic digestion is a biological process that converts many biomass materials into a mixture of 60 percent methane and 40 percent carbon dioxide. This process is used commonly for treating municipal sewage, and the product methane is increasingly used to generate electricity or is injected into the natural gas system. The methane (the major component of natural gas) can be used to fuel steam-electric plants, combustion turbines, reciprocating engine generators or fuel cells. (Additional discussion of combustion turbine technologies is provided in the Nonfirm Strategies section of this chapter.)

Controlled partial combustion of biomass can yield product gasses including carbon monoxide, hydrogen, methane, carbon dioxide and nitrogen. The exact composition of the product depends upon the biomass feedstock and the oxidant. If air is used for combustion, a low heating value (200 British thermal units per standard cubic foot)[2] fuel is produced. Using pure oxygen for combustion produces a fuel of intermediate heating value (600 Btu/scf). For comparison, natural gas has a heating value of about 1,000 Btu/scf. The resulting fuels generally can be

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2./ Standard cubic foot (scf) is one cubic foot of gas at standard temperature and pressure (59°Fahrenheit, atmospheric pressure).

used in the same type of generating equipment as methane, although low-Btu gasses may require co-firing with fuel oil to maintain ignition.

Biomass Liquefaction

Processes are under development for the production of liquid fuels from biomass products. Many processes involve the addition of hydrogen to a carbon-rich feedstock to produce an oil with a high hydrogen-to-carbon ratio. One benefit of liquefaction is the ability to use biomass materials to fuel a wider variety of power plants (including transportation applications that might compete with electric generating applications for fuel supply). A second benefit would be the improved ability to store the product. This would provide a means of smoothing the seasonal fluctuations in supplies of biomass raw materials.

Development Issues

Issues affecting the availability and use of biomass for electric power generation include the effect of competing uses on the availability of residues for fuel, the costs of collecting and transporting these generally low energy density fuels from scattered sources, seasonal and interannual fluctuation in supply, air quality impacts of burning, land impacts of residue removal and global warming considerations.

Competing Uses

The amount of residue available as fuel for electric power generation is constrained by competing uses for these materials. Use of the material as bulk fuel often has the lowest economic value of several possible uses for these materials. For example, residential firewood is a higher value use for some logging residues, pulp chips are a higher value use for some mill residues, and erosion control may be a higher value use for some agricultural wastes. Improvements in collection and transportation methods will not only contribute to an increased supply of these materials for bulk power plant fuel use, but also will expand markets for competing uses. The strength of markets for competing uses adds to the uncertainties regarding the future cost and availability of these materials for electric power generation. For example, increasing restrictions on the use of wood stoves for residential heating in urban areas would depress the market for residential fuel wood and thereby increase the availability of logging residue for bulk fuel. Strong demand for paper will depress the availability and increase the cost of mill residue.

Fuel Collection and Transportation

Logging and agricultural residues are produced at many scattered locations. Use of this material for electric power generation would require establishing systems for the routine collection and transportation of these materials to a central power plant. This problem is complicated by the low energy density of biomass residues, especially agricultural crop residues, which increases the bulk of materials needing to be handled. Logging residues present a further problem in that logging sites are not constant, but move from year to year. Collection and transportation is less of a problem with mill residues, because these are generated at mill sites and often may be used for cogeneration at these same sites. In general, it is not economically feasible to haul biomass residue fuels further than about 50 miles. This limits the fuel supply, and therefore, the size and possible location of biomass-fired power plants.

Fuel Supply Fluctuation

Because biomass residues are produced as a by-product of some other activity, and are subject to competing uses, the supply of biomass fuels may vary significantly, both seasonally and annually. Logging activity varies seasonally and annually as the market for wood products fluctuates, and with it, the supply of logging residue. The production of mill residue also varies with the wood products market, and its availability is further influenced by competition for wood chips by the paper industry. The production of agricultural residues varies with the seasonal harvest cycle, with the agricultural economy and with shifts in crop patterns and weather.

In contemplating large-scale uses of biomass residues for electric power production, it is useful to view this resource as one with firm and nonfirm components, much like the hydropower resource, which has firm and nonfirm components. The feasibility of using biomass residues as power plant fuel can be enhanced by developing methods of "firming" the nonfirm portion of the fuel supply through mechanisms such as improved storage capability, use of back-up fuel supplies and long-term fuel supply contracts.

Air Quality Impacts

Most biomass fuels (except municipal solid waste) are low in sulfur and may be combusted without production of sulfur dioxide. Air quality problems associated with the use of biomass fuels are the control of uncombusted hydrocarbons and particulate material. These are controlled by proper furnace design and combustion control and cyclones, baghouses or wet scrubbers.

Combusting logging and agricultural crop residues under the controlled conditions of a power plant may benefit air quality by reducing the amount of these materials that otherwise would be disposed of using uncontrolled, open burning.

Land Impacts

Use of logging residues, mill residues and agricultural residues for power plant fuel will have no incremental impact on land use and habitat quality, providing that sufficient materials are retained on site to provide erosion control and wildlife cover. The level of use assumed in this analysis would represent only a small portion of total available material, and sufficient material should be available for erosion control and wildlife cover.

Global Warming

The issue of global warming due to increased atmospheric emissions of greenhouse gases may be the most important factor promoting the use of biomass fuels for electric generation. Carbon dioxide is a major greenhouse gas. That is, carbon dioxide, along with other gases, collects in the atmosphere, forming a "blanket" that allows solar radiation to penetrate to the earth's surface, but reduces the radiation's ability to transmit back out of the atmosphere. The result of an excess of greenhouse gases appears to be gradual global warming. All carbon-containing fuels produce carbon dioxide when burned, including coal, natural gas and biomass. Biomass, however, is produced by combining carbon dioxide from the atmosphere with water. Sunlight provides the energy for this process. Thus, if the plants from which the biomass fuels are derived, biomass combustion makes a zero net contribution to atmospheric carbon dioxide concentrations.

Biomass Power Potential in the Pacific Northwest

Because the economy of the Pacific Northwest has been based traditionally on natural resources, large quantities of wastes from the forest products and agricultural industries could be used for electric generation. The type and source of biomass fuel varies widely within the region, both on a geographical basis and over time.

Fuel Supply and Cost

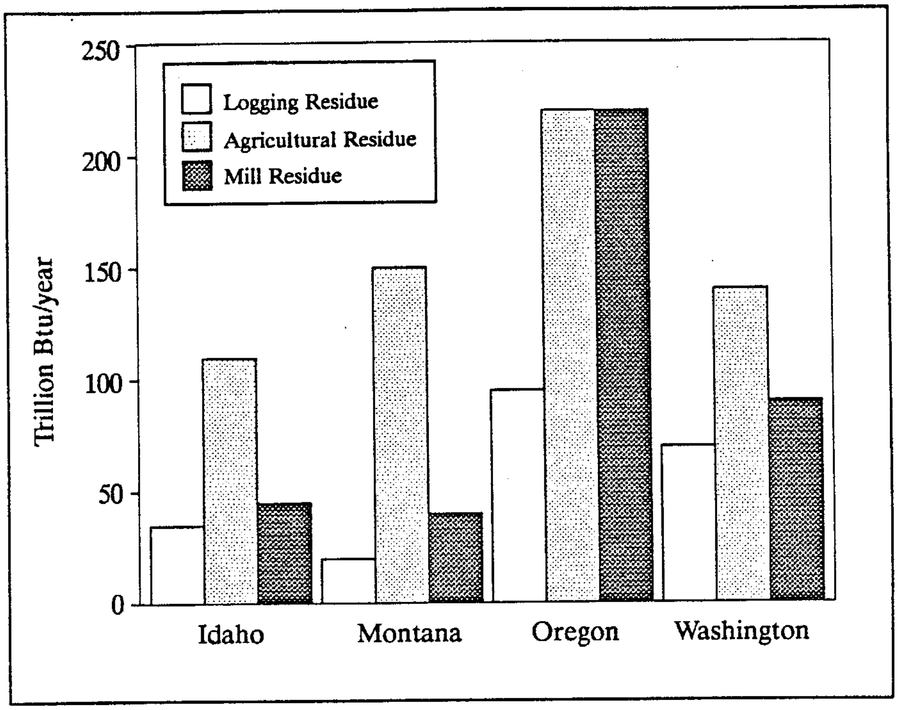
Biomass residue is generated as a result of producing consumer products such as lumber and paper. The volume of residue generated depends upon the quantity of a consumer product produced and a residue factor. For example, logging residues are produced because timber is needed to produce lumber, pulp, or plywood. The residue factor has units of tons of residue/board feet harvested and is a function of both the harvest method and the timber stand characteristics such as the age of the trees and the species. Other materials have residue factors with units of tons of residue per unit of production, and their numerical value depends upon the process or resource being considered.

There are four principal sources of biomass fuels in the Northwest. These are logging residues, residues of wood product manufacturing, agricultural field residues and municipal solid waste. It currently is not considered cost-effective to grow trees specifically for fuel.

Figure 8-1 shows the average quantity of logging, agricultural and mill residues that were produced over the last 10 years for each state in the region. To put this in perspective, compare the total annual average quantity of residues generated in Washington (315 trillion Btu) with Washington's total industrial fuel use for 1986 (284 trillion Btu).

Biomass Residues Produced

Figure 8-1
Biomass Residues Produced—Average Production of Biomass Residues in the Pacific Northwest (1977–1987)



<u>Logging Residues</u>

Primarily because of collection and transportation costs, logging residue is not currently recovered for electric power generation in the Pacific Northwest. The amount of logging residues available for electric power generation is determined by harvest volume, logging practice, stand characteristics, competing uses for logging residue and constraints on the traditional disposal by slash burning.

Harvest volume is predicted to decline in the Pacific Northwest. Residue factors also will decrease as harvests shift to second-growth stands. The net effect of these factors is estimated to be about a 30-percent reduction over the next 20 years (Kerstetter, 1989). New harvesting techniques, such as whole tree harvesting, also may contribute to reductions in the residue factor. Although this practice will reduce collection costs for the remaining residue, it could make the residue more desirable for competing uses.

Competing uses of logging residues include the pulp and paper industry, residential firewood, and the production of particle, fiber and chip-based wood products. The future also might see greater use of chipped logging residue for nutrient recycling and erosion control. Firewood is presently the most significant use of logging residue.

At present, the demand for logging residue imported by competing uses is low, relative to the size of the resource. Therefore, the price for logging residue as electric power generation fuel would be largely determined by collection and transportation costs.

The analysis prepared for the Council (Kerstetter, 1989) estimated a regionwide maximum availability of logging residue for power plant fuel of 36 trillion Btu per year. This amounts to about 20 percent of the annual regional total of logging residue forecast to be produced in the 1991 to 1995 period. This is forecast to decline to about 29 trillion Btu per year in the 2001 to 2010 period. This material would be available at prices of up to $3.30 per million Btu delivered. This price represents large material (minimum 4 to 8 inches in diameter, depending on the terrain) that can either be mechanically collected on flat ground, or on steep slopes it can be skidded to a landing platform. This is basically the same material that is now required by the U.S. Forest Service to be piled and burned as slash. Smaller material, necessary for rejuvenation of soil nutrients and erosion control, is assumed to be uneconomical to recover. The fuel cost estimate includes the cost of transporting the material 50 miles to the generating station. Transportation may take a variety of forms. Some material is large enough to be hauled by log trucks. Where less-steep slopes make smaller material economical to collect, the material might be chipped on site and hauled in chip trucks.

The regional availability of logging residue is forecast to decline from current levels through the end of the planning period. Because biomass power plants would operate for 20 to 30 years, and because most development to meet new load growth would not occur sooner than the late 1990s, the Council has adopted estimates of availability consistent with the post-2001 estimates of logging residue availability. Because of uncertainties affecting the future availability of logging residue as fuel, the Council has developed a conservative probability distribution of logging residue fuel availability. The most likely value of this distribution (see Figure 8-2) is roughly 50 percent of the value estimated in the Washington State Energy Office study.

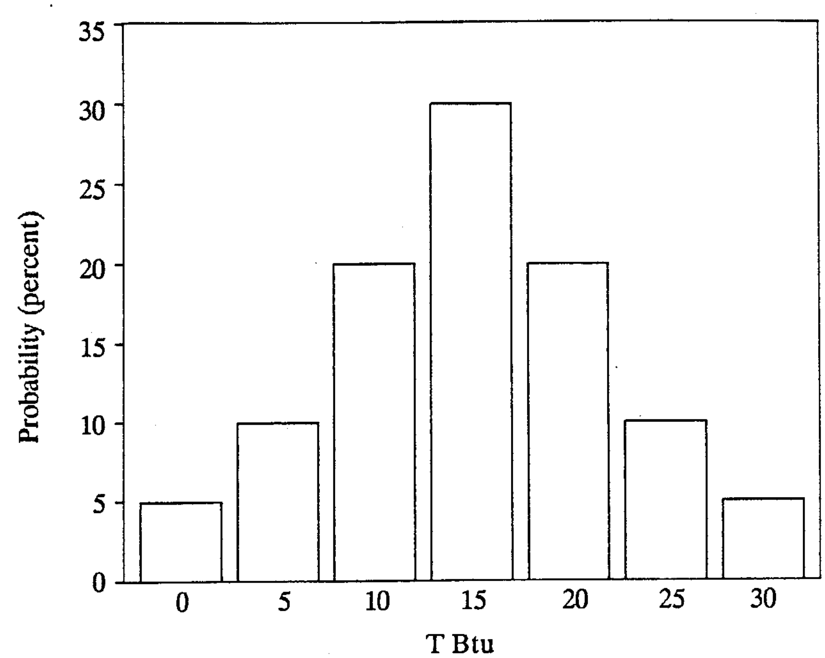
Therefore, the Council has adopted a most probable value of 15 trillion Btu per year and a maximum of 30 trillion Btu per year of logging residues available for electric power generation at a cost of $3.30 per million Btu. This amount would support a most probable value of 110 megawatts and a maximum of 230 megawatts of stand-alone generation. If all of the fuel were used in cogeneration applications, the energy production values would increase the potential to 750 megawatts for the maximum case and 375 megawatts for the most probable case.

Mill Residues

The amount of mill residue produced is a function of activity in the wood products sectors, competing demands for the resource and transportation costs. Wood product residues are used as fiber sources in the production of pulp and paper, to provide process energy to pulp and paper plants, in the manufacture of wood products, and for miscellaneous uses, such as animal bedding and landscaping. Because the demand for and prices offered for mill residues in these categories change over time, sometimes dramatically, it is difficult to predict how much of the resource will be available for electricity generation at competitive prices.

Logging Residue Availability

Figure 8-2
Probable Availability of Logging Residue



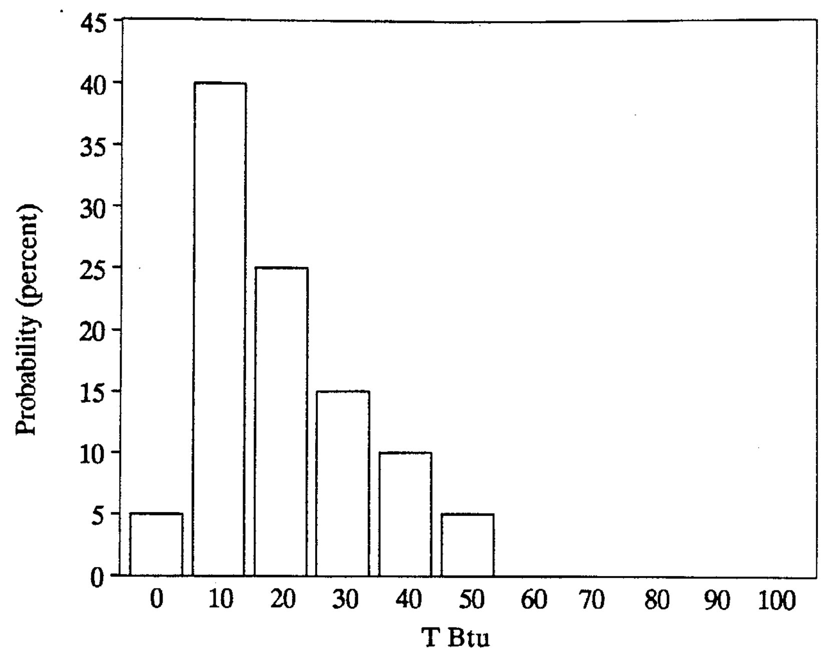
As little as 5 trillion Btu to as much as 78 trillion Btu of mill residues may be annually available in 2010 for electric power generation at prices ranging from $0.40 to $1.00 per million Btu (Kerstetter, 1989). Costs of mill residues are less than those for logging residues, because mill residues are generated at mill sites, reducing collection and transportation costs. But because most competing uses for mill residues represent higher value uses and can outbid power plants for the residue, the Council has adopted a most probable value of 10 trillion Btu and a maximum of 50 trillion Btu of annual fuel availability (see Figure 8-3). The Council has conservatively estimated that this fuel would be available for electric power generation at about $1.00 per million Btu, the upper of the range of costs estimated in the staff issue paper. This fuel could support about 75 to 380 megawatts of stand-alone generation or 250 to 1,250 megawatts of cogeneration. Most of this fuel could be used in cogeneration applications because the resource originates near cogeneration opportunities.

<u>Agricultural Field Residues</u>

Although used to a small degree in California and elsewhere, agricultural field residues are not currently recovered for electric power generation in the Pacific Northwest. The amount of agricultural residues available for electric power generation is determined by volume of the grain and seed crops from which they are primarily derived; the yield, which varies annually; the residue factor for particular crops; competing uses (erosion control and nutrient recycling); and constraints on traditional means of disposal (e.g., field burning).

Mill Residue Availability

Figure 8-3
Probable Availability of Mill Residue



No significant change in the availability of field residues is forecast over the planning period, but significant year-to-year variation will occur, due in a large degree to the weather (Kerstetter, 1989). Good growing conditions produce more residue than poor growing conditions. Thus, the amount of the resource can change dramatically from year to year. From this perspective, much of the field residues resource should be viewed as a nonfirm resource.

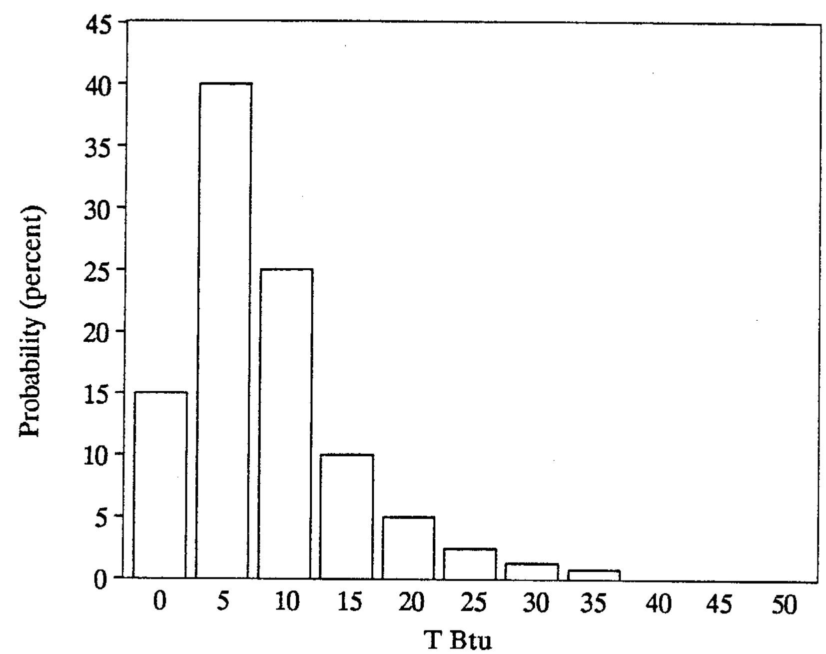
Probably the largest constraint to the use of agricultural field residues for generation is the difficulty of collection and storage. It likely will be feasible to use this resource only where crops are available to support a power plant within a radius of 40 to 50 miles.

Given the high uncertainty due the variability of crop production and the problems of collection and storage, the Council has adopted a most probable availability of agricultural residues for fuel of 5 trillion Btu per year and a maximum availability of 35 trillion Btu (see Figure 8-4). This amount of fuel would support approximately 38 to 266 megawatts of stand-alone generation. Most of this generation likely will be stand-alone, since the locational constraints of the resource will limit opportunities for cogeneration.

This fuel would cost \$2.20 per million Btu (Kerstetter, 1989). This estimate includes costs of collection, transportation up to 40 miles and storage facilities.

Agricultural Waste Availability

Figure 8-4
Probable Availability of Agricultural Residue



Other Biomass Resources

There are other sources of biomass fuels that are not quantified in this power plan. They include spent pulping liquor, urban wood waste, energy crops, landfill gas, digester gas, agricultural processing plant waste, log yard waste, bark from export log operations and others.

Spent pulping liquor is a residue produced during the production of pulp. It contains organics that can be burned and inorganic chemicals that can be recycled back into the pulping process. Chemical recovery boilers are used to recover chemicals and generate steam. In Oregon in 1983, spent pulping liquors provided 38 trillion Btu of energy to the pulp industry while wood wastes provided 10 trillion Btu (Kerstetter, 1989). Some pulp mills use steam from chemical recovery boilers for cogeneration. The potential for new electric generation from pulping liquors is unknown at this time, but it may be large.

Other resources, except energy crops, offer the advantage that they often present a disposal cost to the waste generator. Thus, they have a negative fuel cost. Urban wood waste, log yard waste and bark from export operations could serve as a supplemental fuel to mill residues at particular sites.

Allocation of Biomass Fuels to Cogeneration and Non-Cogeneration Uses

Other factors being equal, cogeneration use of fuel is of greater value than use in stand-alone power plants because of the greater efficiency of fuel use in cogeneration plants. But cogeneration requires a host facility that can use the steam or hot water produced by the cogeneration plant. The cost of transporting biomass fuels and the widely distributed sources of these fuels will limit the amount of this fuel that can be used for cogeneration.

Mill residue offers the greatest potential for cogeneration application, because wood product manufacturing facilities often are good candidates for cogeneration. We assume that about 80 percent of the fuel expected to be available from mill residues (8 trillion Btu) could be used for cogeneration. This amount of fuel could support about 200 megawatts of cogeneration.

Logging residue has more limited potential for cogeneration, because the source of this fuel often is remote from industrial and population centers. But because established transportation facilities are available between logging operations and wood products manufacturing facilities, we estimate that approximately 75 percent of fuel expected to be available from logging residues (11 trillion Btu) would be available for cogeneration operations. This could support about 280 megawatts of cogeneration.

Because of the widely distributed sources and low energy density of agricultural residues, we assume that all of this fuel is used for stand-alone generation.

The assumptions regarding the price, availability and use of biomass residues are summarized in Table 8-3.

Table 8-3
Price and Availability
of Biomass Residue Fuels
(1988 Dollars)

	Availability (TBtu) Generation (Low/Expected/High)	Availability (TBtu) Cogeneration (Low/Expected/High)	Price (delivered) ($/MMBtu)
Logging Residue	0/4/8	0/11/22	$3.30
Mill Residue	0/2/10	0/8/40	$1.00
Agricultural Residue	0/5/35	0/0/0	$2.20
Total (Generation)	0/11/53		$2.38 (ave.)
Total (Cogeneration)		0/19/62	$2.33 (ave.)

The potential for future cogeneration development in the Northwest using biomass fuels is described in the "Cogeneration" section of this chapter. Use of biomass fuels for stand-alone generation is described below.

Representative Biomass-fired Power Plant

A 25-megawatt capacity wood-fired steam-electric plant was selected as the representative stand-alone biomass-fired power plant. This is a commercially-mature technology, available from many suppliers. Other, more advanced technologies are available, but are likely to be used for special situations, such as seasonally-available fuels, where fuel processing, such as liquefaction, might enhance the feasibility of using these fuels.

The cost and performance characteristics of the representative plant are shown in Table 8-4. Construction and operating costs are based on a 1984 study conducted by Seattle City Light and reported in the Kerstetter report. Siting and licensing costs and lead times, and construction lead times are based on a 1982 Council study of methods of shortening power plant development lead times (Battelle, 1982a). Plant performance characteristics, except for equivalent annual availability are typical values reported in the Kerstetter report. A somewhat more conservative equivalent annual availability of 80 percent was used for this analysis.

Table 8-4
Cost and Performance Characteristics of
a Representative Stand-alone Biomass Residue Power Plant
(1988 Dollars)

	25 Megawatt Wood-fired Steam-Electric Plant
Rated Capacity (MW)	25
Peak Capacity (MW)	25
Equivalent Availability (%)	80%
Heat Rate (BTu/kWh)	15,000
Siting & Licensing Cost ($/kW)[b]	35.00
Option Hold Cost ($/kW/yr.)	7.00
Construction Cost ($/kW)[a]	1,450
Fixed O&M Cost ($/kW/yr.)	41.30
Variable O&M Cost (mills/kWh)	3.5
Post-op Capital Replacement Cost ($/kW/yr.)	b
Siting & Licensing Lead Time (months)	24
Construction Lead Time (months)	30
Operating Life (years)	30

a "Overnight" costs (excludes interest during construction).
b Post-operational capital replacement costs are included in fixed operation and maintenance costs.

Reference Energy Cost Estimates

Reference levelized energy costs for the representative biomass-fired power plant, using the three types of biomass fuels, are shown in Table 8-5. These costs were calculated using the reference financial and service date assumptions described in the introduction to this chapter. The plants are assumed not to be displaceable, and costs are calculated using a capacity factor equal to plant availability. Included in Table 8-5 are real levelized energy costs (1988 dollars), nominal costs over the anticipated 30-year service life of the representative plant, and nominal costs normalized to a 40-year service period.

Table 8-5
Reference Energy Costs for
Representative Stand-alone Biomass Residue Power Plants

Fuel	Fuel Price ($/MMBtu)	Energy Costs (cents/kWH) Real ($1988)	Nominal (30-year)	Nominal (40-year)
Mill Residue	$1.00	4.3	7.6	8.5
Logging Residue	$3.30	7.7	13.5	15.1
Agricultural Residue	$2.20	6.1	10.7	11.9
Weighted Average	$2.35	6.2	10.9	12.2

Biomass Resource Planning Assumptions

The biomass fuel supply of 11 trillion Btu, at an average cost of $2.35 per million Btu, expected to be available for stand-alone power plants should be sufficient to produce about 90 average megawatts of electricity. But a much larger amount of biomass residue might become available for generating plant fuel if fuel collection, storage and transportation constraints are resolved. Resolution of these problems might result in the availability of as much as 53 trillion Btu annually of biomass residues as fuel for stand-alone power plants. This amount of fuel could support about 430 megawatts of stand-alone generation.

As described earlier, 19 trillion Btu of biomass fuels were assumed to be used for cogeneration. The cost and availability of this fuel was used in the analysis of cogeneration potential described later in this chapter. The remainder of this fuel is assumed to be available for use in stand-alone generating plants. The characteristics of this resource block are shown in Table 8-6.

Conclusions

Large quantities of biomass residues are produced by the forest products and agricultural industries in the Pacific Northwest. Some of this material is presently used for industrial process heating, residential heating and electric power generation. However, there is the potential to use additional material for electric power generation.

Logging, mill and agricultural field residues offer the greatest potential as fuel for new electric power generation or cogeneration. Some mill residues are currently used for electric power generation, but there is little use of logging or agricultural residues for this purpose in the region.

It is conservatively estimated that 30 trillion Btu of logging, mill and agricultural residues could be used annually for new electric power generation or cogeneration in the Northwest. This amount represents but a small fraction of the total resource not used for other purposes (see Figure 8-5).

Cogeneration is the preferred use of biomass fuels, but transportation constraints will limit the amount of this fuel that can be used for this purpose. The Council assumed that 19 trillion Btu of the available total can be used for new cogeneration. This amount of fuel can support about 480 megawatts of cogeneration. Cogeneration potential is further analyzed in the cogeneration section of this chapter.

Table 8-6
Biomass Resource Planning Characteristics
(Stand-alone Plants)

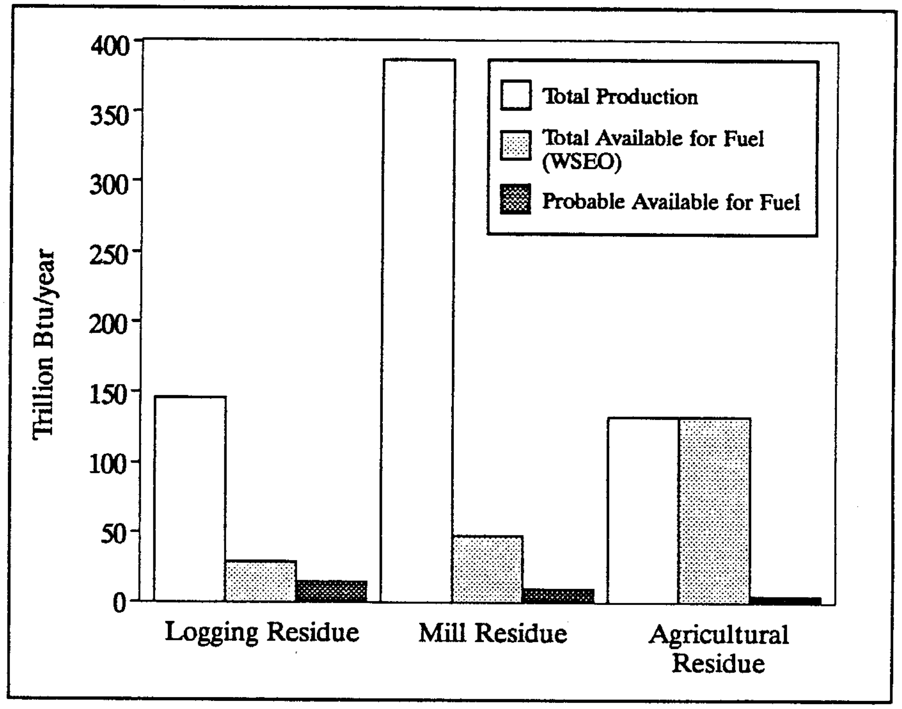
	Biomass I
Total Capacity (MW)	113
Total Firm Energy (MWa)	90
Unit Capacity (MW)	22.5
Seasonality	None
Dispatchability	Must-run
Siting and Licensing Lead Time (months)	24
Probability of S&L Success (%)	75
Siting and Licensing Shelf Life (years)	5
Probability of Hold Success (%)	75
Construction Lead Time (months)	36
Construction Cash Flow (%/yr.)	25/50/25
Siting and Licensing Cost ($/kW)	$35
Siting and Licensing Hold Cost ($/kW/yr.)	$7
Construction Cost ($/kW)	$1450
Fixed Fuel Cost ($/kW/yr.)	$0.00
Variable Fuel Cost (mills/kWh)[a]	35.0
Fixed O,M&R Cost ($/kW/yr.)	$41.00
Variable O&M Cost (mills/kWh)	4.0
Earliest Service	1996
Peak Development Rate (units/yr.)	5
Service Life (years)	30
Real Escalation Rates (%/yr.)	
Capital Costs	0%
Fuel Costs	0%
O&M Costs	0%

a At a weighted average fuel cost of $2.35 per million British thermal units.

Biomass Potential

Figure 8–5
Potential Availability of Biomass Fuels (2001–2010)

(Note: Total production for agricultural residue does not include amount retained for erosion control.)



The balance of this fuel can be used in stand-alone generating plants. These plants, most of which will be relatively small and scattered, can be expected to produce about 90 megawatts of energy in total. With fuel costs averaging $2.35 per million Btu, these plants could produce energy at a cost of about 12 cents per kilowatt-hour (nominal, 1988 in-service date, normalized to a 40-year service life).

Use of biomass residues for electric power generation should create few environmental impacts. Air quality is likely to improve by controlled combustion of materials that might otherwise be burned in the open.

Major constraints to the expanded use of biomass residue for fuel appear to include the development of efficient collection and transportation mechanisms, development of cost-effective, small-scale power plants that can be located near the resource, and the development of methods for ensuring constant fuel supplies. The Council will request its Research, Development and Demonstration Advisory Committee to identify activities that might be undertaken to expand the future use of biomass resources for electric power generation.

References

Battelle, Pacific Northwest Laboratories. 1982a. *Development and Characterization of Electric Power Conservation and Supply Resource Planning Options.* Prepared for the Northwest Power Planning Council, Portland, Oregon.

Battelle, Pacific Northwest Laboratories. 1982b. *Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest: Volume V - Biomass.* Prepared for the Northwest Power Planning Council, Portland, Oregon.

Kerstetter, J.D. 1989. *Assessment of Biomass Resources for Electric Generation in the Pacific Northwest.* Prepared by the Washington State Energy office for the Northwest Power Planning Council, Portland, Oregon.

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Coal

The combustion of coal to produce electric power is one of the oldest and best-established methods of generating electricity. The Pacific Northwest power system receives output from 13 coal-fired units totaling 6,702 megawatts of nameplate capacity. The regional shares of these plants supply 3,957 megawatts of peak capacity and 3,154 megawatts of energy.[3] Because development of the Northwest electric system focused on low-cost hydropower through the mid-1960s, this coal-fired generation capability consists of plants of generally contemporary design.

Except for mines supplying the Centralia Generating Station in western Washington, little coal is mined within the region. However, proven reserves of low sulfur coal are available from sources near the region far in excess of those required to meet electricity needs for the foreseeable future. The extent to which coal plays a major role in meeting future electrical needs will be governed by resolution of concerns associated with continued large-scale development of coal. These concerns include restoration of strip-mined lands, atmospheric releases of sulfur dioxide, nitrogen oxides and carbon dioxide, siting of power plants and transmission lines to bring power from minemouth plants to load centers and disposal of ash and sludge from power plant operations.

Because of the abundance of low-cost coal available for regional use, and proven technology for generating electricity from coal, coal-fired power plants were used as the basis for long-term marginal electricity costs in the 1983 and 1986 plans. The 1983 and 1986 power plans used a single cost for electricity from new coal-fired power plants. That cost, about 9.7 cents per kilowatt-hour (in 1988 dollars), was based on the estimated cost of producing electricity from a representative coal-fired power plant located at Boardman in eastern Oregon. This cost determined the maximum amount of electricity from any other resource, including conservation, that could be cost-effective.

Actual development of new coal-fired power plants likely would be characterized by progressively increasing costs. Coal prices would increase as demand increased, requiring mining of less accessible seams. Better sites would be taken by early development leaving more difficult sites for later. And perhaps most significantly, continuing large-scale development of coal would lead to more stringent and expensive environmental control measures. The net effect of these factors would be a coal supply curve of progressively increasing cost, similar to the supply curves for other resources.

3./ Not included in these figures is the J.E. Corette plant of Montana Power Company, or the Montana Power Company shares of the Colstrip units. About 30 percent of the capability of these resources (excluding Colstrip 4) is available to the region. This fraction (which may change through time) represents the portion of total Montana Power Company load located within the Pacific Northwest. By Pacific Northwest planning conventions, the regional shares of Montana Power Company resources are treated as imports to the region.

In the 1983 and 1986 plans, it was understood that development of the large amounts of coal required to meet high load growth cases within the 20-year planning period would be unlikely. The forecast need for large-scale development of new resources occurred late in the 20-year planning period. By that time it was thought that other more cost-effective or environmentally benign resources would become available to substitute for much of the coal shown in the resource portfolio for the high load growth cases.

A specific limit to new coal development over the 20-year planning period was established in the 1989 Supplement to the 1986 plan. Although resources needed to meet high load growth conditions increased by nearly 5,000 megawatts in the supplement, the amount of coal considered to be available for the portfolio was limited to 5,425 megawatts of energy--the amount needed to meet high load growth cases in the 1986 Power Plan.

Based on an analysis of the availability and cost of electricity from new coal-fired power plants undertaken for this plan, the Council considers 4,800 megawatts of electrical energy from new coal-fired power plants to be available for the resource portfolio of the Draft 1991 Power Plan. This energy is expected to be available at costs ranging from 7.7 to 9.6 cents per kilowatt-hour.[4] Energy from new coal-fired power plants could be available to meet regional load as early as 1997.

Technology

The pulverized-coal-fired steam-electric power plant is an established technology for producing electricity from coal. Advanced coal-based generating technologies, including atmospheric fluidized bed combustion and gasification-combined-cycle plants are now commercially available. More advanced technologies, including pressurized fluidized bed combustion and magnetohydrodynamics are under development.

A pulverized-coal-fired power plant consists of a coal-handling and preparation section, a boiler and a steam turbine generator. Coal is pulverized in the preparation section and burned in the boiler, generating steam. The steam operates the steam turbine-generator, producing electricity. A cooling system transfers waste heat from the steam turbine to the atmosphere, and an emission control system removes particulates and sulfur oxides from the combustion gasses.

Pulverized-coal-fired plants are tested, reliable designs. Flue-gas desulfurization and particulate control equipment permits these plants to meet current U.S. New Source Performance Standards promulgated under the Clean Air Act. Although a mature technology, enhancements in plant control, efficiency and reliability have improved the cost and performance of new pulverized-coal-fired plants compared with earlier designs. A wide range of unit sizes is available, allowing capacity additions to be matched to load growth. Smaller plant sizes have somewhat

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4./ "Reference" costs. See discussion of reference costs in introduction to this chapter.

shorter construction lead times and greater reliability, but they are generally more costly (per unit capacity) to build and operate than larger units.

An atmospheric, fluidized-bed coal-fired (AFBC) power plant is similar in overall configuration to a pulverized-coal-fired plant but uses a different type of furnace to combust the coal. A fluidized-bed furnace burns coarsely ground coal in a bed of limestone particles suspended by continuous injection of air from below. The limestone scavanges sulfur directly from the burning coal. With many coals, fluidized-bed furnaces can meet current federal New Source Performance Standards without use of flue-gas desulfurization equipment. Elimination or reduction of flue-gas desulfurization equipment saves capital and operating costs, and improves plant efficiency. Also, the lower combustion temperatures of AFBC plants reduce formation of nitrogen oxides. AFBC plants also eliminate the need for coal pulverizers and produce a dry solid waste instead of a wet flue gas desulfurization sludge.

AFBC technology has been employed in the non-utility industry for many years, but utility use is recent in the United States. Three utility AFBC units, ranging in size from 20 megawatts to 125 megawatts, are in service in the United States. A fourth unit of 160 megawatts is scheduled for service this year. Tacoma Light and Power's 38-megawatt Steam Plant No. 2 is being repowered with fluidized bed furnaces that will be capable of burning coal, wood refuse and municipal solid waste. Some in the utility industry believe that the next generation of central-station coal plants will be largely of AFBC design.

In pressurized fluidized-bed combustion (PFBC) designs, fuel is burned in a pressurized chamber using a fluidized bed. The hot combustion gases power a gas turbine prior to final heat recovery in a steam boiler. This combined-cycle design results in higher energy conversion efficiencies. The first U.S. demonstration of PFBC technology for utility application has been announced. This will be a 330-megawatt repowering of two units of American Electric Power's Philip Sporn plant in New Haren, West Virginia (Electrical World, June, November 1988).

A gasification-combined-cycle (GCC) power plant consists of a coal gasification plant and a combined-cycle combustion turbine power plant. The gasification section produces low or medium-Btu synthetic gas that is used to fuel a combined-cycle combustion-turbine power plant. GCC plants feature a high degree of modularity, significantly improved control of atmospheric emissions and high energy conversion efficiencies. The combustion turbine and combined-cycle sections can be installed prior to the gasification plant and operated on natural gas until fuel prices or load conditions warrant installation of the gasification section. The gasifier therefore imparts fuel flexibility to the highly efficient combined-cycle plant.

Coal gasification technology has been available for many years and was once widely used to produce "town gas" in cities (including several in the Northwest) where natural gas was not locally available. The technology fell into disuse as the long-distance natural gas transmission system was constructed, but was resurrected as interest in substitutes for natural gas rose in the 1970s. Improved versions of the technology have been developed since then. Utility-scale application of the coal-gasification, combined-cycle plant concept was demonstrated at the 100-megawatt Coolwater, California, plant.

Magnetohydrodynamics (MHD) is a process for converting heat energy directly into electricity. High combustion temperatures, combined-cycle operation and direct conversion of thermal to electrical energy could offer the advantages of high energy conversion efficiency. The MHD concept also promises improved control of atmospheric emissions.

An MHD power plant would consist of a combustor, an MHD "channel," a heat-recovery boiler and a steam turbine generator. Pulverized coal would be burned at high temperature and pressure in the combustor. Potassium "seed," injected to ionize the hot gas, would create electrically conductive plasma. The plasma, passing through the MHD channel, where a strong magnetic field would be established by use of superconducting magnets, would create an electrical potential across electrodes installed in the channel. The plasma would discharge from the channel to a heat-recovery boiler. Steam from this boiler would drive a conventional steam turbine-generator, augmenting the power production of the MHD channel.

Development of MHD technology has advanced to the point where utility-scale demonstration projects are being considered.

Development Issues

This section presents an overview of the principal issues associated with large-scale development of coal-fired plants. These issues include air quality impacts, site availability, water impacts, solid waste production, site availability, coal transportation and electric power transmission. A general summary of these issues is provided, as well as descriptions of mitigative measures. Specific impacts are difficult to assess with accuracy due to geological, demographic, topographic, and climatic factors that vary on a case-to-case basis.

Air Quality

The principal atmospheric emissions from the combustion of coal are sulfur oxides, nitrogen oxides, particulates and carbon dioxide.

Sulfur Dioxide

Sulfur is a naturally-occurring constituent of coal. Sulfur concentrations range from about .5 to 4 percent. Western coals usually have a low sulfur content (less than 1 percent). The sulfur in coal is converted to sulfur dioxide, a gas, in the combustion process. The sulfur dioxide that is released to the atmosphere is slowly transported, sometimes over large distances and is gradually converted to sulfuric acid or sulfate. Acid precipitation forms in the atmosphere from chemical conversion of sulfur and nitrogen compounds, under the influence of oxygen, water and sunlight to form sulfuric acid and nitrous and nitric acids. Hydrochloric acid, created partially to combustion of coals that contain chlorine, also contributes to acid precipitation formation. The resulting precipitation from rain, snow, dust, etc. has an adverse impact on all forms of terrestrial and aquatic life. The potential impacts resulting from these emissions and secondary products include human health effects, crop and forest damage, corrosion of metallic and masonry structural materials and visibility degradation.

Low sulfur coals (less than 1 percent sulfur) are widely available in the west and are used to control sulfur dioxide emissions on existing and new plants. But for new coal-fired power plants, federal New Source Performance Standards require additional removal of sulfur dioxide even if low sulfur coal is used. The most common method used today to reduce sulfur dioxide emissions from pulverized-coal-fired power plants is wet lime or limestone flue gas scrubbing. In flue gas scrubbing systems the flue gas is exposed to a slurry of lime or limestone that absorbs the sulfur dioxide and reacts with it to form calcium sulfite or sulfate. These reaction products and unreacted limestone are dewatered for disposal, generally in landfills, although some is recycled for its gypsum content. Flue gas desulfurization systems can remove more than 95 percent of the sulfur dioxide content of raw flue gas.

Advanced coal-based technologies offer alternative ways to control sulfur dioxide emissions. In fluidized bed plants lime is supplied to the fluidized bed to scavenge sulfur prior to formation of sulfur dioxide. No additional control may be required for high-sulfur coals. However, fluidized bed combustion plants using lower-sulfur coals may require supplementary flue gas desulfurization to meet emission standards.[5] Coal gasification plants incorporate sulfur removal equipment in the product gas cleanup section to remove sulfur from the product gas prior to combustion. Marketable pure sulfur can be produced as a byproduct of gasification plant sulfur removal operations.

Nitrogen Oxide

When coal is burned, several oxides of nitrogen are formed by the oxidation of nitrogen contained in coal and in the combustion air. These are released from the boiler stack. Nitrogen oxides can form nitrosamines, highly potent carcinogens in aqueous solutions. In addition, nitrogen oxide can cause damage to crops and forests because it is a forerunner of such photochemical oxidants as ozone and can form acid rain, along with sulfur oxides.

The formation of nitrogen oxide in pulverized coal-fired power plants can be reduced by combustion modification techniques that reduce the availability of nitrogen. These techniques include low-excess air firing and staged combustion. Advanced coal-based technologies provide additional ways to control nitrogen oxide formation. Combustion temperatures of fluidized bed plants are lower than for conventional furnaces, retarding formation of nitrogen oxide. Medium-Btu coal gasification plants use oxygen fed to the gasifier, thus avoiding introduction of nitrogen to the combustion process and consequent formation of nitrogen oxide. Nitrogen oxide, however, can be formed during the combustion of coal-derived fuel gas in the combustion turbine section of the gasification combined-cycle powerplant. Nitrogen oxide formation in the combustion turbine can be controlled by low-excess

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5./ This apparent anomaly occurs because federal New Source Performance Standards establish not only an absolute level of sulfur dioxide emissions, but also require removal of a certain percentage of sulfur oxides, even when low-sulfur coals are burned.

air burners and water injection (to reduce combustion temperatures). Nitrogen oxide in the combustion turbine exhaust can be further lowered by catalytic reduction.

Particulates

Small solid particles formed during combustion, varying in size from 0.01 to 10 microns[6] in diameter can be carried out in the flue gas. These very small particles can be respired and can cause human health effects.

Electrostatic precipitators, baghouses, and scrubbers are the typical emission control systems employed to collect particulates. Precipitators and baghouses are typically more than 99 percent efficient.

Carbon Dioxide

Carbon dioxide is produced by combustion of any fossil fuel. Carbon dioxide is a "greenhouse" gas (i.e., it allows short wave-length solar radiation to pass, but absorbs longer wave-length outgoing radiation). Atmospheric levels of carbon dioxide and other greenhouse gasses are increasing and, if the increase continues, it may raise the average temperature at the earth's surface. Uncertainty exists regarding the potential magnitude of such a temperature rise and the global carbon cycle in general. Because of these uncertainties, it is unclear at this time whether global warming will become a constraint to the use of coal-based power generation.

Factors affecting the carbon dioxide release per unit of electric energy output are the heat content of the coal, the carbon content of the coal and the efficiency of the energy conversion process. Carbon dioxide releases therefore can be reduced somewhat, but not eliminated by coal and technology selection. Removal and disposal of carbon dioxide from flue gas is possible in theory. But it is thought to be very expensive, perhaps doubling the cost of electricity from a conventional pulverized-coal-fired plant. Alternatively, carbon dioxide releases could be mitigated by biologically fixing atmospheric carbon dioxide through reforestation and other processes.

Water Impacts

Potential water impacts may result from cooling tower blowdown, ash handling, waste waters and water consumption.

Cooling Tower Blowdown

Steam-electric power plant condenser cooling water typically is cooled using evaporative cooling towers or cooling ponds. Due to partial evaporation of this cooling water, contaminants such as mineral salts that enter the system with the makeup water become more concentrated. In addition, chlorine or other biocides usually are added to control biofouling. Thus, portions of the cooling water must

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6./ One micron is one-millionth (10^{-6}) of a meter.

be withdrawn and replaced with fresh water to prevent salt buildup. The water that is withdrawn ("blowdown") could be damaging locally or when the water enters surface water or groundwater. Waste water treatment techniques that can be used include chemical precipitation or sedimentation and dechlorination. "Zero discharge" plant designs are available that do not discharge the blowdown directly but use it for scrubber makeup, ash sluice water, and other in-plant purposes. Also, fully closed-cycle condenser cooling systems are available requiring little makeup and blowdown. Because they are somewhat less effective than evaporative cooling systems, plant efficiency is penalized.

Ash Handling Waste Waters

Bottom ash (residue accumulating at the bottom of the furnace) and fly ash (residue in the flue gas stream) are produced during combustion. Gasification systems produce a waste slag from the gasifiers and ash removed from the product gas stream. Ash is typically transported as a slurry in wet-ash handling systems. Wet ash handling systems produce waste waters that are discharged as blowdown. Dissolved heavy metals can accumulate in the ash ponds and cause adverse effects to ground or surface waters and to aquatic organisms. Ash handling waste water treatment includes chemical precipitation/sedimentation and neutralization and use of lined ash disposal pits.

Water Consumption

Water is required for general plant services, boiler makeup and condenser cooling. The amount of water required for a coal plant could cause potential conflicts over water rights, especially for plants sited in arid sections of Montana and Wyoming. Water consumption also could reduce in-stream flows, which could reduce the amount of water available for other users and could adversely affect water quality and fish populations.

Cooling systems constitute a large part of in-house water needs. Evaporative cooling systems result in continuous loss of water to the atmosphere. This loss can be reduced using full closed-cycle (dry) cooling. Gasification combined-cycle power plant designs further reduce cooling water requirements, because only the steam turbine section of the power plant requires condenser cooling.

Withdrawal of water from a river, lake or ocean for power plant services and condenser cooling can impact fish or intake screens. The rate of this impingement is directly related to intake velocity at and around the intake structure and also other physical and biological phenomena. The highest impingement rates occur in areas with concentrations of juvenile fish near high-volume shoreline intakes. Potential impacts depend on the intake design.

Solid Waste

The three significant solid waste materials produced by pulverized coal plants are fly ash, bottom ash, and scrubber sludge. The bottom ash from a fluidized bed plant contains the sulfur compounds resulting from in-bed removal of sulfur. Gasification produces a slag, equivalent to bottom ash, and fly ash collected during product gas cleanup. Scrubber sludge is not produced in gasification systems as the sulfur is converted to elemental sulfur upon removal from the product gas streams. The potential impacts of these products depend on their chemical composition (largely determined by the coal composition), the manner of disposal, and the location of the disposal site.

Ash

Bottom ash and fly ash collected dry with electrostatic precipitators or baghouses can be disposed of directly or added to scrubber sludge for stabilization. Typically, disposal is in ponds or landfills.

Fly ash could leach out of the ponds or landfills, causing possible accumulations of trace elements and salts in surface water and/or groundwaters. Leaching can be managed by proper site selection and pond lining.

Scrubber Sludge

Scrubber sludge consists of large concentrations of chloride, calcium and sulfate. Disposal options for scrubber sludge consist of direct ponding and dewatering followed by landfilling. Direct ponding requires large areas of land and also poses a leaching problem. Pond lining can prevent such leaching.

Site Availability

The availability of sites for coal-fired power plants is more constrained than for any other generating technology, with the possible exception of nuclear. Factors that must be considered include the ability of the airshed to absorb the atmospheric discharges of the plant, availability of water for cooling and other plant uses, proximity to the transmission grid, proximity of rail or water transportation for coal (if remote from the minemouth), and availability of land for disposal of ash and flue gas desulfurization products. Only a limited number of regional sites can meet these requirements.

The amount of land required for a 500-megawatt coal-fired steam-electric plant is approximately 650 acres, including land that would be required for solid waste disposal. Co-siting of units will reduce the amount of land required per unit due to the sharing of facilities. Land requirements are relatively insensitive to coal-fired power plant design. Most of this land would be lost as natural habitat.

Coal Transportation

Because of the large volumes of coal required by a central-station coal-fired power plant, rail or water transportation must be available if the plant is to be remotely sited from coal mines. Consideration must be given not only to the proximity of the plant site to rail or water services, but also to the ability of the selected mode of transportation to provide a reliable supply of coal (a 1,200 megawatt coal project would require about 180 rail cars of coal per day when in full operation). Upgrades to the coal transportation route such as rail and roadbed improvements, double track, additional sidings, improved signal systems, grade separation and urban bypass lines might be required for safe and reliable operation.

Electric Power Transmission

An alternative to transportation of coal into the region would be the siting of coal plants at the minemouth outside the region. This would require construction of a long-distance, high-voltage transmission line to tie the plants into the regional grid. A 1,200-megawatt coal project would require a 500 kilovolt single-circuit alternating current transmission intertie, and possibly a second circuit for reliability purposes. Direct-current transmission may be economical for interconnection of very remote sites, such as in eastern Montana or Wyoming. Direct-current transmission requires only two conductors in lieu of the three conductors required for alternating-current transmission. This may reduce aesthetic impacts and right-of-way requirements. Construction of transmission lines can be expensive, and their siting extremely difficult.

Coal Development Potential in the Pacific Northwest

The general approach to assessing future coal development potential in this power plan was conceived by the Council's Generating Resources Advisory Committee. The objective of the Committee's recommended approach is to simulate the likely future cost and availability of power from new coal-fired power plants by estimating the costs and limits to development at prospective siting areas in the Northwest. All major foreseeable economic costs are contained, including:

- fuel cost;
- fuel transportation cost;
- fuel transportation system upgrade cost;
- power plant siting and licensing cost;
- power plant construction cost;
- environmental compliance costs;
- power plant operation and maintenance costs;
- transmission grid interconnection costs; and
- transmission losses.

Five general siting areas were identified, and for each siting area a specific, representative site selected. Possible coal sources, coal transportation modes and routes were identified using a Bonneville study of regional fossil fuel availability. Delivered fuel prices for each site were estimated using a coal price forecasting process developed by Bonneville.

Representative power plant cost and performance characteristics were estimated for each site using the average costs of a range of possible plant designs. Finally, with the assistance of Bonneville transmission engineers, likely routes for transmission grid intertie lines were selected and transmission costs and losses estimated.

Power Plant Siting Areas and Representative Sites

Potential siting areas for new coal-fired power plants within and near the region include eastern Washington, eastern Oregon, eastern Montana or Wyoming, northern Nevada and western Washington or Oregon. Currently, the Washington Water Power Company has licenses for a two-unit coal-fired power plant at Creston, Washington. This site was therefore chosen as a representative eastern Washington site. Although the licenses originally were issued for a four-unit plant of about 2,000 megawatts capacity, it is likely that additional air quality constraints near the site would limit new capacity to about 1,000 megawatts if conventional pulverized coal-fired plants with flue gas desulfurization are used.

Plants also might be sited along the Columbia River in eastern Oregon. Here, the main line of the Union Pacific railroad provides good access to the coal fields of eastern Montana and Wyoming. Because additional units were licensed for construction at the Boardman site, this site was chosen as the representative eastern Oregon site. Other possible sites in eastern Washington and eastern Oregon have adequate access to water, rail transportation and transmission.

In lieu of transporting coal by train, new coal-fired power plants could be constructed near coal mines, and the electricity could be transmitted to regional load centers. Minemouth power plants could be located near coal fields in Montana, Wyoming, Utah, British Columbia or Alberta. However, with additional transmission comes increasing land use, aesthetic and visual impacts, and concerns regarding the health effects of electromagnetic fields. The Wyodak site in eastern Wyoming has been licensed for an additional unit, but Colstrip was chosen as a representative minemouth site because of the established transmission corridor from this site.

Good rail access to Utah and Wyoming coal fields and a central location relative to the population centers of the Pacific coast has resulted in attention being given to the development of coal-fired power plants in Northern Nevada. One proposal, now abandoned, was to develop a coal-fired power complex near Thousand Springs. This site was licensed for eight 250-megawatt coal-fired power plants to be developed by Sierra Pacific Resources. The plan was to market the output of these plants to customers throughout the West. New transmission lines would be required to move energy from the Thousand Springs site to the Northwest. The Thousand Springs project was abandoned in the summer of 1990 because of objections of neighboring states regarding air quality impacts, and because of lack of power sales contracts.

Finally, there is the possibility of developing additional coal-fired generating plants in western Washington or Oregon. Adding generation near the load centers of the Northwest has the advantage of avoiding electric power transmission costs, losses and environmental impacts. Moreover, it may be possible to site plants such that condenser waste heat could be used to supply industrial, commercial or district heating loads. However, western Washington or Oregon siting may lead to air quality impacts and would require additional rail haul. For this reason, it is likely that if additional coal-fired generating plants were built in western Oregon or Washington there might be increased requirements for environmental controls and additional costs for coal transportation systems to support the plant.

The representative plant sites are shown in Figure 8-6.

Fuel Supply and Cost

Abundant supplies of low-sulfur coal are available in the western United States and Canada. A 1988 Bonneville study examined sources of coal for new Northwest coal-fired power plants. These coal sources (see Figure 8-6) include the Powder River Basin fields of eastern Wyoming and Montana, the East Kootenay region of British Columbia, the Green River Basin of southwestern Wyoming and the Unita Basin of northeastern Utah and northwestern Colorado. Coal also could be obtained from Alberta, or by barge, from the Vancouver Island Quinsam mines or the Chuitna mines of Alaska. Coal from fields around Centralia in western Washington is used to fire the nearby Pacific Power and Light Centralia project, however, this coal is of low grade and its continued availability in quantities sufficient to support additional large-scale, coal-fired plants is questionable.

A possible coal source for new coal-fired power plants located at each of the five representative sites was identified using the minemouth coal cost estimates and transportation costs developed in the Bonneville fuel supply study. Were plants actually to be constructed at these sites, competitive bidding for fuel and transportation contracts might result in coal being obtained from alternative sources. The sources used in this analysis, however, are considered to be representative of the fuel supply alternatives for new plants within each siting area. The coal sources, and fuel transportation modes used for each representative site are shown in Table 8-7.

Delivered coal prices (exclusive of rail upgrade costs) were taken from a coal price forecasting model developed in 1990 by Bonneville. This model incorporates uncertainty into 20-year projections of delivered coal prices. An annual series of point estimates of coal commodity and rail transportation costs are multiplied by pricing factors taken randomly from specified probability distributions. This process is repeated several hundred times for each year of the price series using a Monte Carlo simulation. The mean and standard deviation of the resulting distribution describe the distribution of possible delivered coal costs for each year of the resulting price series. These price series are summarized in Table 8-8.

Transmission Routes

Figure 8–6
Representative Power Plant Sites and Corridors for Transmission Grid Interrconnection

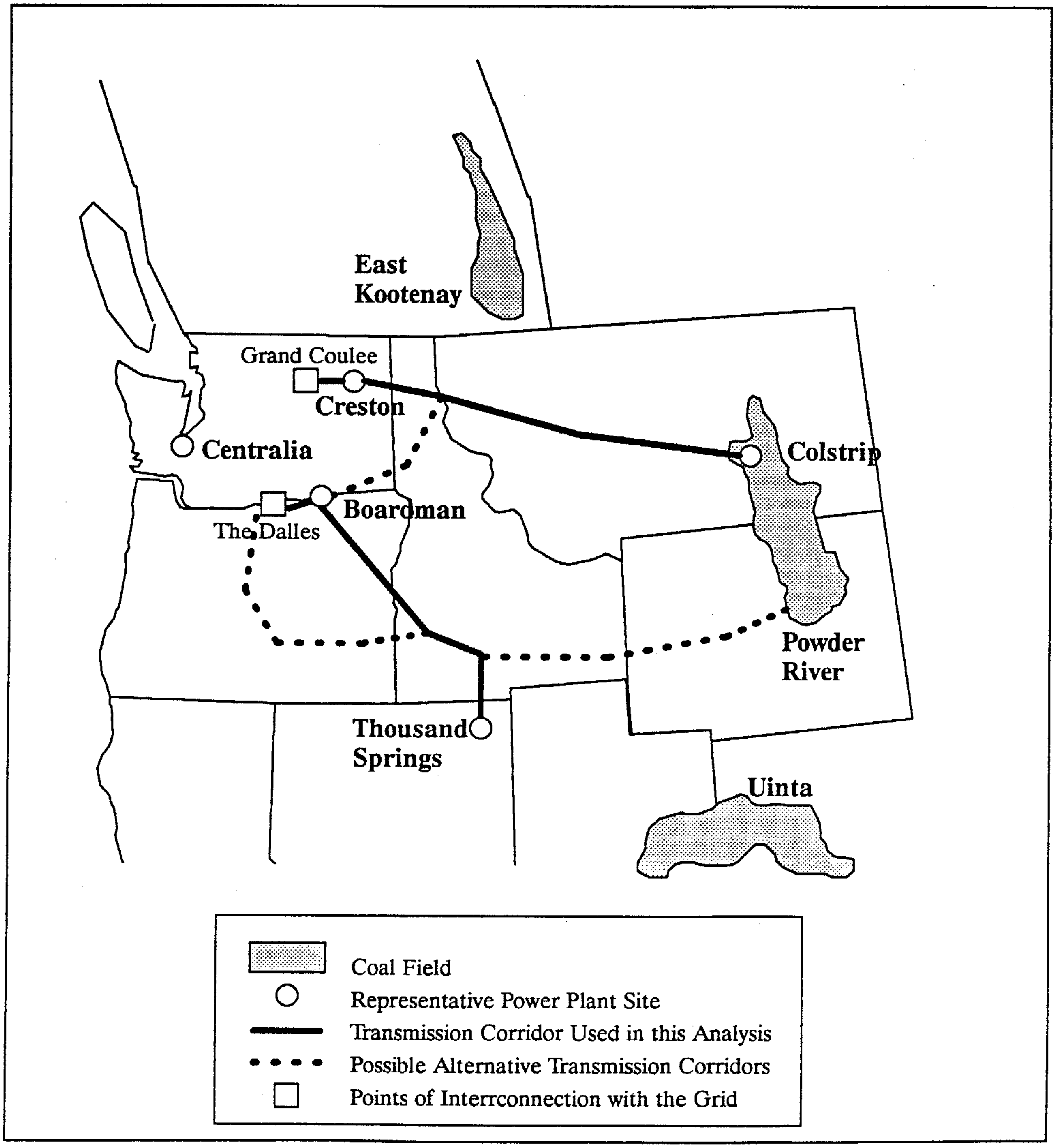

Table 8-7
Assumptions Used for Development of the Base Case Coal Supply Curve

Siting Area	Representative Site	Coal Source	Fuel Transp.	Rail Upgrade (miles)	Generating Technology	SO_2 (%)	NO_x (%)	Emissions Offset	Transmission Intertie[a] (miles)
Eastern MT/ Wyoming	Colstrip	Powder R.	Truck or Conveyor	N/A	Pul. Coal Stm. Elec.	95%	60%	None	650
Eastern WA	Creston	E. Kootenay	Rail	40	"	95%	60%	None	83
Eastern OR	Boardman	E. Kootenay	Rail	None	"	95%	60%	None	80
Northern NV	Thousand Springs	Uinta	Rail	14	"	95%	60%	None	550
Western WA/ Oregon	Centralia	E. Kootenay	Rail	None	"	95%	60%	None	None

a Plus 10 mile interconnection included in basic power plant cost estimates.

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Fuel Transportation

Four of the representative plant sites would require rail transportation of coal from the mine to the plant site. This would be accomplished using unit trains. Such trains typically consist of several locomotives and about 100 hopper or gondola rail cars, each carrying about 100 tons of coal. A 1,000-megawatt coal plant averaging about 750 megawatts of electricity production would require more than 2.7 million tons (27,000 railcars) of coal per year (about 5 unit trains per week), of high energy content East Kootenay or Unita coal. If coal of lower energy content were used, more would be needed.

Transport of this tonnage of coal may require track, control and signal upgrades for reliable, safe and expeditious delivery. The Council solicited comment from several railroads serving the Northwest to estimate the extent of trackage upgrades required to support transportation of this amount of coal. Burlington Northern responded that its existing routes to the Northwest could bear an additional 10 million tons of coal per year without additional track construction. Plant capacity of 1,000 megawatts at each of the three representative sites that might receive coal over Burlington Northern trackage would require about 8.2 million tons of coal per year. For this reason, it was assumed that the only track upgrade required would be for branch lines to the representative plant sites. The estimated length of branch line requiring upgrade for the affected sites is shown in Table 8-7. Track upgrade is estimated to average $1 million per mile.

Unit train power normally is furnished by the railroad, whereas dedicated rolling stock is normally furnished by the power plant operator. The cost of rolling stock is included in the delivered coal prices discussed earlier.

Representative Coal-fired Power Plants

The Council has assessed the cost and performance characteristics for several types and sizes of coal-fired power plants. The most recent assessments, developed for the 1989 Supplement to the 1986 Power Plan, are documented in Appendix 8-A. The cost and performance characteristics of these plants are reproduced in Table 8-9. For this analysis the Council used costs and performance characteristics that are the average of the representative 250-megawatt and 603-megawatt pulverized coal-fired units. Though it is not possible to predict what specific technologies or size of units would be developed to meet future needs, most generating plants should fall within the range established by these two plant types.

Previous power plans assumed that new coal-fired power plants would be required to meet federal New Source Performance Standards (NSPS) for particulates, oxides of nitrogen and sulfur dioxide emissions. For plants using low-sulfur Western coal, the federal NSPS require 70 percent removal of sulfur dioxide and combustion control technologies achieving 60 percent removal of oxides of nitrogen. The Council received comment that new plants likely would be required by the states to install emission control technology more stringent than that required by federal new source performance standards. The control levels on two of the more recently constructed plants in the region--Colstrip 3 and 4--were cited by Montana Department of Natural Resources and Conservation as examples.

Table 8-8
Coal Quality and Delivered Prices

	Powder River Basin at Colstrip	East Kootenay at Creston	East Kootenay at Boardman	Unita at Thousand Springs	East Kootenay at Centralia
Origin	Colstrip, MT	Elkford, BC	Elkford, BC	Price, UT	Elkford, BC
Destination	Colstrip	Creston, WA	Boardman, OR	Thousand Springs, NV	Centralia, WA
Haul Distance (miles)	0	330	500	400	750
Heat Value (Btu per pound)	8,300	12,000	12,000	12,000	12,000
Sulfur (%)	0.42	0.70	0.70	0.70	0.70
Medium Price Forecast (1988$/MMBtu):					
1990	0.48	1.24	1.39	1.29	1.61
1991	0.48	1.26	1.41	1.30	1.63
1992	0.49	1.27	1.43	1.30	1.65
1993	0.49	1.29	1.45	1.31	1.66
1994	0.50	1.30	1.46	1.31	1.68
1995	0.50	1.32	1.48	1.32	1.70
1996	0.51	1.33	1.50	1.32	1.72
1997	0.51	1.35	1.52	1.33	1.74
1998	0.52	1.37	1.54	1.33	1.76
1999	0.52	1.38	1.56	1.34	1.78
2000	0.53	1.40	1.58	1.34	1.80
2001	0.54	1.42	1.60	1.35	1.82
2002	0.54	1.44	1.62	1.35	1.84
2003	0.55	1.45	1.65	1.36	1.86
2004	0.55	1.47	1.67	1.36	1.88
2005	0.56	1.49	1.69	1.37	1.90
2006	0.56	1.51	1.71	1.37	1.92
2007	0.57	1.53	1.73	1.38	1.94
2008	0.57	1.55	1.76	1.39	1.97
2009	0.58	1.57	1.78	1.39	1.99
2010	0.58	1.58	1.80	1.40	2.01
Std Deviation (σ)	0.22	0.46	0.45	0.36	0.47
growth rate	0.95	1.22	1.30	0.41	1.12

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Table 8-9
Cost and Performance Characteristics of Coal-fired Power Plants (1988 Dollars)

	Atmospheric Fluidized Bed Coal-fired Power Plant[h]	Coal Gasifier Combined-Cycle Power Plant[g,h]	250 MW Pulverized Coal-Fired Steam Electric Plant[a,h]	603 MW Pulverized Coal-Fired Steam Electric Plant[a,h]	Composite Coal-Fired Plant[e]
Plant Configuration	1-197 MW Unit	1-420 MW Unit[f]	2-250 MW Units	2-603 MW Units	2-427 MW Units
Rated Capacity (MW/Unit)	197	419	250	603	427
Peak Capacity (MW/Unit)	NA	451	262	633	448
Equivalent Annual Availability (%)	81%	80%	77%	75%	76%
Heat Rate (Btu/kWh)	9,885	9,270	11,005	10,856	10,930
Siting & Licensing Cost ($/kW)[b]	$41	$38	$32	$23	$28
S&L Hold Cost ($/kW/yr)	$1.40	$0.50	$0.90	$0.80	$0.85
Construction Cost ($/kW)[a]	$1,792	$1,850	$1,695	$1,245	$1,470
Fixed O&M Cost ($/kW/yr)[c]	$37.10	$61.20	$32.80	$20.50	$26.65
Variable O&M Cost (mills/kWh)	4.8	0.8	3.0	1.9	2.5
Siting & Licensing Lead Time (months)[d]	48	48	48	48	48
Construction Lead Time (months)	64	39	60	72	66
Service Life (years)	30	30	40	40	40

a Performance figures are for each unit of a two-unit plant.
b "Overnight" costs (excludes interest during construction).
c Includes post-operational capital replacements.
d For full site-selection process.
e Characteristics are average of 250 megawatt and 603 megawatt plants.
f Two 139 megawatt GE MS7001 combustion turbines, one heat recovery steam generator and one 141 megawatt steam turbine-generator.
g Figures are for full development of a gasifier combined-cycle power plant. Development of this plant could be staged.
h See the *1989 Supplement to the 1986 Power Plan* for additional information concerning these technologies and sources of cost and performance information.

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This analysis, therefore, is based on "best state" levels of control, i.e., control levels comparable to Colstrip 3 and 4. These plants are controlled to 95 percent removal of sulfur dioxide and 60 percent removal of oxides of nitrogen. The incremental construction cost of increasing sulfur dioxide removal from 70 percent to 95 percent is estimated to be about $110 per kilowatt (California Energy Commission (CEC), 1989). Incremental operation and maintenance costs are estimated to be .1 cent per kilowatt-hour (CEC, 1989).

Transmission Interties

The bulk of the region's electrical load is located west of the Cascades Range, whereas four of the five representative plant sites are located on the east side. New transmission capacity would be required to interconnect these sites to the regional grid. The fifth site, Centralia, would be interconnected to existing nearby transmission lines running north-south along the Interstate 5 corridor.

Bonneville transmission engineers identified possible transmission intertie routes from the four eastern sites to the Puget Sound load center (see Figure 8-6). But for consistency with the other resource assessments of this plan, the "regional grid" was defined as Grand Coulee or The Dalles, whichever is nearest to the four eastern sites. These latter distances were used in this analysis (see Table 8-7). While over time, additional trans-Cascades transmission reinforcement likely will be required to support west-side load growth, for purposes of this plan the cost of these reinforcements is attributed to load growth and not to specific resource additions.

In 1990 Bonneville also supplied estimates of transmission intertie construction, operating costs and line losses for several line configurations. Using these estimates, the two representative configurations shown below were selected for this analysis.

Capacity	1,200 MW	2,400 MW
Capital Cost (million dollars per mile)	$600	$1,200
O&M Cost (dollars per mile, per year)	$2,400	$4,800
Line Losses (percent per 100 miles)	0.8 percent	0.8 percent

Reference Energy Costs

Reference levelized energy costs for five representative sites were calculated using the project development assumptions described in the introduction to this chapter. The plants were assumed to be fully dispatchable, with an annual average capacity factor of 71 percent. Capital costs were amortized over the 76 percent equivalent availability; production costs were based on the 71 percent capacity factor.

Total project costs included fuel, fuel transportation, power plant and transmission intertie costs. Power delivery to the grid and effective plant heat rates were calculated using transmission intertie losses. The resulting reference delivered energy costs for the five representative sites are shown in Table 8-10.

Table 8-10
Reference Levelized Energy Costs for Representative Coal Plants

Siting Area/Representative Site	Real Cost ($ 1988) (cents/kWh)	Nominal Cost (1988 Service) (cents/kWh)
Eastern Montana (Colstrip)	3.9	7.7
Eastern Washington (Creston)	4.5	8.9
Eastern Oregon (Boardman)	4.7	9.3
Northern Nevada (Thousand Springs)	4.9	9.6
Western Washington/Oregon (Centralia)	4.9	9.6

Resource Availability

The development of any new large-scale coal-fired power plants in the Northwest likely will face significant constraints. Of the five sites considered here, the Creston site probably faces the fewest constraints. This site is essentially fully licensed, although a determination of "best available control technology" (BACT) is required prior to reissue of a Prevention of Significant Deterioration (PSD) permit for atmospheric releases. Although the site initially was licensed for 2,000 megawatts of capacity, only about half that capacity is thought developable using conventional technology because of nearby lands more recently redesignated as Class 1 (Pristine) air quality designation. Accordingly, we have assumed that 1,000 megawatts of capacity, producing (at the busbar) about 750 megawatts of energy, could be developed at this site. We assume that units at Creston could be in service within seven years of a decision to proceed (24 months to complete siting, licensing and preliminary engineering; 60 months for construction).

Rail transportation, a water supply and nearby transmission lines give the Boardman site reasonable potential for the development of new coal capacity. Net air emissions could be reduced below existing levels, if necessary, by securing offsets at the existing Boardman plant. Though nearing expiration, a license for two additional units of 1,350 megawatts (maximum) capacity each[7] is currently in effect for this site. We assume that a new license for at least 1,000 megawatts of capacity (750 megawatts of energy at the busbar) could be secured at this site. We assume that a new unit at the Boardman site would require four years for licensing and preliminary engineering and five years for construction.

The Northern Nevada rail corridor offers ready rail access to coal supplies and relatively uncontroversial transmission routes to the Northwest grid. The principal constraints to development of new coal-fired capacity appear to be water supply and air quality concerns. The Thousand Springs venture failed partly because of air quality concerns raised by neighboring states. Air quality concerns might be overcome by use of low-emission technology such as gasifer-combined cycle units, or

7./ The existing license was issued for either new coal or nuclear units, hence the large unit capacity limits.

by securing offsets from the existing plants operating in the region. Despite the failure of the Thousand Springs proposal, the advantages of this area continue to offer potential for development. We assume that 1,000 megawatts of new capacity--half the projected size of the Thousand Springs project--could be developed in this area. We assume that a new unit at the Thousand Springs site would require two years for licensing and preliminary engineering and five years for construction.

Western Washington and Oregon sites offer good rail or water access, proximity to west-side load centers and adequate water supplies. Air quality concerns and possibly land use conflicts likely would be the dominant issues for western Washington or Oregon sites. Because the existing Centralia units are not fitted with flue gas desulfurization equipment, a net reduction in current levels of sulfur dioxide emissions could be secured by installing sulfur control equipment at the existing plant. Offsets could be secured for the other controlled pollutants, but it is not known whether a "no-net" increase situation for other pollutants could be achieved is not known. We assume 1,000 megawatts of new coal-fired capacity could be developed in western Washington or western Oregon. We assume that a new unit in western Washington or western Oregon would require four years for siting, licensing and preliminary engineering and five years for construction.

Eastern Montana or Wyoming sites, by minimizing coal transportation costs, result in the lowest estimated costs of the five siting areas examined. These sites offer some protection from inflation, because a larger proportion of the total cost of delivering power to the load centers would be fixed. The principal issues associated with the development of sites in this area would be transmission right-of-way, air quality and water supply. Water supply issues could be addressed by use of zero-discharge designs and dry cooling, if necessary. Sulfur dioxide releases might be mitigated by offsets at existing plants in the area, though the ability to offset other regulated emissions is not known. Air quality concerns also could be mitigated by use of low-emission technologies, especially coal-gasification combined-cycle plants. The major impediment to the development of new capacity in this area, as evidenced by the controversy attending construction of the Colstrip interties, would be securing right-of-way and permits for the transmission intertie. A new corridor or widening of an existing corridor could accommodate the transmission of about 2,400 megawatts of capacity. We assume that a new unit in eastern Montana or Wyoming would require four years for siting, licensing and preliminary engineering and five years for construction.

About 4,800 megawatts of electric energy from new coal-fired power plants could be made available over the 20-year planning period under these supply assumptions. This is approximately the same as the amount developed to meet regional needs between the mid-1960s and the mid-1980s--a period of generally high electrical load growth.

Planning Assumptions

For subsequent analysis of the role of coal in the resource portfolio, each power plant site was treated as a separate resource block. Each block is comprised of several units assumed to be separately developable, but with cost and performance characteristics similar to other units within the block.

Characteristics of the five blocks are summarized in Table 8-11.

Table 8-11
Coal Resource Planning Characteristics

	Eastern Montana	Eastern Washington	Eastern Oregon	Northern Nevada	Western WA/OR
Total Capacity (MW)[a]	2,242	980	980	942	987
Total Firm Energy (MWa)[a]	1,704	745	745	716	750
Unit Capacity (MW)[a]	448	490	490	471	493
Seasonality	None	None	None	None	None
Dispatchability	Full	Full	Full	Full	Full
Siting and Licensing Lead Time (months)	48	24	48	24	48
Probability of S&L Success (%)	70	80	80	75	50
Siting and Licensing Shelf Life (years)	5	5	5	5	5
Probability of Hold Success (%)	75	75	75	75	75
Construction Lead Time (months)	60	60	60	60	60
Construction Cash Flow (%/yr.)	b	b	b	b	b
Siting and Licensing Cost ($/kW)	$28	$14	$28	$14	$28
Siting and Lic. Hold Cost ($/kW/yr.)	$0.85	$0.85	$0.85	$0.85	$0.85
Construction Cost ($/kW)	$1,995	$1,710	$1,712	$2,026	$1,665
Fixed Fuel Cost ($/kW/yr)	$0.00	$2.88[c]	$0.00	$1.05[c]	$0.00
Variable Fuel Cost (mills/kWh)	5.2	13.6	15.2	14.1	17.1
Fixed OM&R Cost ($/kW/yr.)	$30.30	$27.10	$27.10	$30.00	$26.65
Variable O&M Cost (mills/kWh)	3.6	3.8	3.8	4.0	3.8
Earliest Service	2000	1997	2000	1997	2000
Peak Development Rate (units/yr.)	1	1	1	1	1
Operating Life (years)	40	40	40	40	40
Real Escalation Rules (%/yr.)					
Capital Costs	0	0	0	0	0
Fuel Costs (See Table 8-8)					
O&M Costs	0	0	0	0	0

a Delivered to the grid.
b Construction cash flow for each unit is 2/8/25/40/25 percent.
c Rail upgrade cost.

Conclusions

An estimated 4,650 megawatts of energy could be obtained by development of new coal-fired power plants. This energy, delivered to the regional transmission grid, would cost from 7.7 to 9.6 cents per kilowatt-hour.[8]

Coal-fired power plants currently provide about 3,200 megawatts of energy to the Northwest system. Although an essentially unlimited supply of low-cost, low-sulfur

8./ For "Reference" energy costs, see introduction to this chapter.

coal is available to the Northwest, siting difficulties, public resistance to new transmission lines and atmospheric emissions may constrain the development of new coal-fired power plants. Water supply may be a concern in arid areas. Impacts of air emissions might be partly mitigated by the use of low-emission/high efficiency generating technologies and by securing offsets at existing plants. Water supply concerns can be mitigated by use of zero-discharge designs and dry cooling.

An important issue pertaining to development of any new coal-fired capacity is the possible significance of carbon dioxide production in contributing to global warming. Some mitigation may be feasible through biological carbon fixation (e.g., reforestation) use of high-quality coals and high-efficiency technologies. The best strategy at present appears to be deferral of decisions to construct additional coal-fired capacity until better understanding of carbon dioxide production and global warming effects is achieved.

Securing sites and permits for new plants and transmission lines will shorten development lead time and help resolve uncertainties associated with this resource.

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Cogeneration

Cogeneration is the use of one primary fuel source for simultaneous generation of both thermal and electrical energy. Cogeneration improves overall energy efficiency. Instead of simply burning fuel to create steam needed in industrial or commercial processes, cogeneration adds an electricity generation step and uses the "waste" heat from electricity generation for the industrial process. Alternatively, the fuel can be used initially for process or space heating, and the "waste" energy from this process used for electric power generation.

In previous Council plans cogeneration has played only a minor role. But this power plan recognizes that cogeneration has the potential of being a significant resource for the region. The increased potential of cogeneration results from improved analysis of cost-effective applications and a growing consensus among utilities and industry representatives that there is a large amount of technically feasible cogeneration in the region. Acceptance of cogeneration's potential also has been increased by a growing understanding of the changing utility environment. These changes support an increased role for dispersed, non-utility resources like cogeneration.

Cogeneration Technology and History

Cogeneration is not a new or exotic development. In the late 1800s and early 1900s, it was standard practice for industry to generate its own electricity, and much of that took the form of cogeneration. It has been estimated that in 1890, 50 percent of all electricity used in the United States was cogenerated.[9] During this time, self-generated electricity was more reliable and less expensive than utility-generated power.

As utility systems expanded in the 1930s and began benefitting from economies of scale, self-generated electricity became less economically attractive to industry. By 1950, the share of self-generated electricity cogenerated had fallen to 17 percent, and by 1977 it was only 3 to 4 percent.

Beginning in the late 1970s, there was a resurgence of cogeneration in the industrial sector. In 1980, there were an estimated 20,000 megawatts of cogeneration capacity at 916 facilities throughout the United States. Since then the amount probably has doubled. The rekindled interest in cogeneration has been a result of decreasing oil and natural gas prices, increasing electricity prices, and government policies that were developed to deal with the energy problems that surfaced in the 1970s. Cogeneration has been encouraged specifically by the Public Utility Regulatory Policies Act (PURPA), various tax provisions, and fuel use restrictions on utilities embodied in the Fuel Use Act. PURPA provided a

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9./ Much of the background information discussed here is taken from a November 1988 Electric Power Research Institute, Final Report EM-6096, entitled, *Cogeneration and Utilities: Status and Prospects*, November 1988.

stimulus to cogeneration by requiring utilities to purchase electricity from qualifying cogeneration facilities at the utility's avoided cost for new generating resources and by requiring utilities to provide back-up electricity and supplemental power to cogenerators at fair rates. The relevant portions of the Fuel Use Act and the tax provisions have since been repealed or weakened but PURPA remains in effect.

Cogeneration is most attractive in industries and commercial applications with large and relatively constant thermal energy requirements. In 1985, five industrial sectors accounted for 95 percent of the cogenerated electricity in the United States (EIA, 1988). These industries and their share of cogeneration are shown in the table below:

Paper and Allied Products	47.1 percent
Chemicals and Allied Products	28.4 percent
Petroleum and Coal Products	7.9 percent
Primary Metal Industries	6.5 percent
Food and Kindred Products	5.2 percent

The cogeneration of electricity is regionally concentrated. About 64 percent of it occurs in the South. This is due to large concentrations of pulp and paper manufacturers in the Southeast and chemical and petroleum refining activity in Texas and Louisiana. Although the Northwest has a large pulp and paper industry, cogeneration is not as prevalent here due to our low electricity prices.

Nationwide, cogeneration that has been developed under PURPA uses a variety of fuel types. Over half of it is natural gas-fired (58 percent); coal is 19 percent, and biomass, waste, and other fuels accounted for most of the rest. In the Northwest, much of the cogeneration takes place in lumber or pulp and paper industries and uses wood, black liquor and other biomass fuels.

Technology is playing an increasing role in expanding the applications of cogeneration both in smaller industrial settings and in the commercial and multifamily residential sectors. Increasing electricity prices, the decrease in natural gas prices since 1986, and the various policy incentives discussed above have led to the development of packaged cogeneration units. These units are produced as integrated cogeneration systems. They come in various sizes, are easy to install and can take advantage of the economy of mass production. As a result, the per-unit capital cost of a packaged cogeneration system can be significantly less than that of a typical site-built cogeneration system.

The development of packaged cogeneration units has expanded the potential of cogeneration into many types of activities. To be most attractive for cogeneration, reasonably large and well-balanced thermal and electric demands are needed on a fairly continuous basis. Particularly attractive for cogeneration are large buildings or complexes of buildings, such as hospitals, universities, shopping malls, hotels, large office buildings, and apartment buildings.

According to recent data collected by the Bonneville Power Administration, there are approximately 900 megawatts of existing cogeneration capacity in the Pacific Northwest. About 85 percent of capacity is concentrated in the pulp and paper and lumber and wood products industries. However, only a portion of this capacity is available to the regional power system. The Council's 1986 plan identified between 307 and 368 megawatts of installed cogeneration capacity in the

Northwest under contract to electric utilities. The discrepancy between the Bonneville survey and the 1986 Council plan could be due to cogeneration that is not contracted to electric utilities (self-generation), installations that are not currently being operated, new capacity added since 1986, cogeneration sold out of the region, and more comprehensive data collection since 1986. However, the amount of cogeneration that appears in the Pacific Northwest Utilities Conference Committee's (PNUCC's) *Northwest Regional Forecast* for 1989-90 is much smaller, at 73 megawatts nameplate capacity. In accordance with the *Northwest Regional Forecast* (the source assumptions regarding the existing power system used for this plan), the amount of cogenerated electricity that is relied on by utilities to meet loads in the region is 58 megawatts peak and 46 megawatts average energy. An additional 45 megawatts of cogenerated power is sold out of the region.

Based on the history of cogeneration, it is clear that future cogeneration potential in large industrial applications is largely a question of economics rather than technology. The region's industries hold a fairly large potential for cogeneration, but the low electricity rates and ample, reliable supplies of electricity have discouraged cogeneration development as an alternative to purchasing power from utilities. However, as the need for power surfaces, utilities, in the current environment, probably will work with industry to develop cogeneration for regional use.

Development Issues

There are a number of issues that relate to the analysis and implementation of cogeneration as a regional electricity resource. These include: the integration of cogenerated electricity into the physical and financial utility system; the amount of electricity generated relative to the thermal requirements of the host facility; the availability and price of fuels used for cogeneration; the provisions for risk sharing in cogeneration contracts; and environmental considerations. Some of these issues have been addressed in analysis and public comment, others can be resolved only on a project-by-project basis.

Utility Interest

Cogeneration can be utility-owned, customer-owned, owned by a third-party developer, or jointly owned by combinations of these three entities. The electricity produced can be used on-site to reduce or eliminate purchases from the electric utility, sold to the utility, or both. The electricity output can be matched to the thermal requirements of the host facility, or excess electricity can be generated.

Cogeneration shares with conservation certain characteristics that may inhibit utility interest in promotion of the resource. If the utility does not own the cogeneration facility, then current regulatory treatment does not allow the utility to earn a return on expenditures to secure power from the facility. If the cogenerated electricity reduces utility sales to the cogenerator, or is sold to the utility at an avoided cost that is higher than industrial retail rates, then it is likely these will be increased costs to other utility customers. Although costs to all customers may be lower in the long run, there is a short-term impact on non-participants, as may be the case for conservation. Regulatory reform that severs utility profits from sales and encourages utility acquisition of the lowest-cost resources should resolve these concerns.

Oversizing

If high prices are available for cogenerated electricity, cogenerators may install facilities that will produce more electricity than is consistent with the industry's thermal load requirements. Under these conditions, the industry becomes a power generator, not just a cogenerator. This is known as "oversizing." These incentives have led in some areas to cogeneration plants that generate far more electricity than justified by the thermal requirements at the site; these plants have been referred to as "PURPA machines."

The degree to which oversizing is allowed has a significant effect on estimated cogeneration potential. Discussion with regional utilities and industries has yielded two perspectives. First, if it is economical to oversize, and regulation permits it, then no attempt should be made to constrain it. This view holds that there is no harm in allowing cogenerators to maximize return by installing oversized systems when it is economical to do so. Arguments in favor of allowing oversizing include:

- Oversizing does not violate current PURPA provisions that allow up to 95 percent of the useful energy output of a cogenerator to be electrical energy. Therefore, oversizing is consistent with federal policy.

- Anticipated future growth in thermal requirements may call for installing oversized systems today that will be balanced systems in the future.

- The electricity sales from oversizing can provide enhanced economic vitality for a facility and provide secondary economic benefits.

- Oversizing may lead to installation of cogeneration systems which, although oversized, retain improved overall fuel use efficiencies compared to stand-alone generation.

- Oversizing, by encouraging installation of new equipment designed and operated to current regulations, may promote reduction in environmental impacts.

Some of the arguments against oversizing include:

- Significant oversizing can lead to reductions in overall fuel use efficiency. Once the point of thermal balance has been exceeded, there is no use for the additional waste heat from the electrical generation process. The excess generating capability has the same characteristics of a stand-alone electrical generating station. If its marginal efficiency is less than that of central-station technologies that can utilize the same fuel, efficiency can be improved by limiting the cogeneration facility to thermal balance, and developing additional capacity using central-station electrical generation.

- Control of emissions can be easier at central-station generating plants. There are fewer point sources for emissions, and central-station facilities typically are monitored and regulated more closely than smaller industrial and commercial facilities.

- Oversizing may promote excessive reliance on the use of natural gas and lead to vulnerability to natural gas price volatility and supply constraints.

If the trend toward competitive bidding continues, it should result in pressure to provide electricity as cheaply as possible. This should create a general tendency toward the more efficient size configurations, that is, toward thermal balance. Meanwhile, the Council encourages the development of thermally balanced cogeneration systems.

Fuel Supplies and Prices

Regional cogeneration potential is limited both by the availability of "host" facilities with suitable thermal loads and by the availability and price of fuel. Fuels used by cogenerators in the Northwest primarily are biomass residues and spent pulping liquor in the wood products and pulp and paper industries, and natural gas in other applications.

In 1989, the Council released an issue paper on biomass resources, prepared by James D. Kerstetter of the Washington State Energy Office. This report includes estimates of the amount of biomass residues and associated prices potentially available for electricity generation. This assessment concluded that in the Northwest there is potential for greatly increased utilization of biomass residues for power plant fuel. There is considerable uncertainty regarding the amount of biomass fuel that might be available for new cogeneration applications.

Contributing to the uncertainty are: 1) competing uses for biomass material, 2) logging and agricultural residue, for example, previously have not been used as fuel in the Northwest, and 3) future production of these materials is unknown. The amount of biomass residue potentially available as fuel might be as great as 115 trillion Btu annually, enough to support about 2,900 megawatts of cogeneration. But, because of the great uncertainty regarding the availability of this fuel, the Council currently assumes only 30 trillion Btu will be available for electricity generation. Of this portion, 19 trillion Btu are assumed to be available for cogeneration. Further discussion of the availability and cost of wood residue fuels is provided in the biomass section of this chapter.

The Council hired a consulting firm to study the availability and cost of natural gas both for firing combustion turbines and for cogeneration. The consultants concluded it is likely there will be adequate supplies of natural gas at the producer level to support the Council's proposed levels of gas use for combustion turbines and cogeneration (Economic Insight, Inc., 1989). Similarly, industrial reviewers of the cogeneration studies concluded that fuel supply is likely to be stable over a wide range of consumption. The limiting factor on gas availability will be access to transportation. This is especially true in the near- and mid-term future. In the long term, if the demand for gas is strong enough, sufficient transportation capacity will be constructed. Gas transportation is thought to be institutionally easier to construct than electric transmission and, consequently, can be more responsive to increases in demand.

In spite of the optimistic conclusions of the consultant, significant concerns remain about future supplies and costs of natural gas. Much of the discussion centers around the desirability of using natural gas directly in end uses instead of using it to generate electricity in combustion turbine plants. This issue does not apply to the use of natural gas in a cogeneration unit. Cogeneration is a very efficient use of natural gas. Nevertheless, fuel price can have a significant effect on the cost-effectiveness of cogeneration and represents a significant uncertainty and risk for power planners.

Further discussion of the availability and cost of natural gas is provided in the nonfirm strategies section of this chapter.

Risk Sharing

Unlike conventional utility resource development, the development of resources such as cogeneration by independent developers offers the possibility of transferring some, or all of the risk associated with resource development and operation to the independent developer. However, the utility may have to pay a higher price for independently developed cogeneration than for resources developed by the utility itself, in compensation for risk assumed by the cogeneration developer. For example, a substantial portion of the risk of new resources occurs because of uncertain future fuel prices. Utilities often can pass through the effects of fuel price increases incurred during the life of their own generating plants, whereas a cogeneration developer may have to include fuel price risk in an "up-front" power sales agreement. Industry representatives have said that if the region wants to ensure the availability of cogeneration to meet future regional loads, utilities and regulatory agencies must be willing to share the risk. Returns should be appropriate to the risks that are being borne. One party cannot be expected to bear significant risk without compensation. An acquisition mechanism that compensates risk-bearers will increase the likelihood that the resource is available for development. As an example, some fraction of the cogenerator's monthly fuel cost could be a "pass through," similar to the way a utility's fuel is handled.

Environmental Considerations

The environmental effects of cogeneration depend on the type of fuel used. In general, the emissions from cogeneration are similar in nature to the emissions of stand-alone generation from the same fuel sources. The magnitude of emissions per unit of electrical production, however, is a function of the efficiency of the cogeneration plant and the extent of emission control.

There are some environmental benefits that derive from the energy efficiency of cogeneration. Because the process uses waste heat, the amount of fuel burned to cogenerate, and therefore the amount of emissions, is potentially less than if the thermal energy and electricity were generated separately. The actual emissions, however, depend on the level of emission control, which may be less stringent for cogeneration plants than for central-station electric generating plants. Also, if the thermal and electric loads are not matched, and the cogeneration plant does not use all of the waste heat, then the emissions might be greater than if the electricity were produced in a larger and more efficient combustion turbine.

With growing applications of small-scale cogeneration, two particular problems may arise. The emissions may be more dispersed and closer to densely populated areas. In addition, small scale applications generally are less subject to environmental controls as larger utility generating plants. These problems can be addressed with more stringent environmental control requirements for cogeneration.

Competition with Conservation

The growth of small-scale cogeneration in the commercial sector raises the issue of the efficiency and environmental desirability of cogeneration versus end-use efficiency improvements to building shells and end uses of electricity. Energy efficiency in commercial buildings has not been given the same level of incentive and promotion as cogeneration, and yet end-use efficiency improvements may be more cost-effective than small-scale cogeneration. Studies have shown that in many cases, the attractiveness of cogeneration projects diminishes when applied to more efficient buildings. Conversely, conservation would appear less cost-effective in a building with a cogeneration system. These trade-offs need to be considered in implementing a regionally cost-effective power system.

Cogeneration Potential in the Pacific Northwest

There have been nearly 30 studies of the cogeneration potential of the Northwest. These studies used different methods and time horizons and have come to a wide variety of conclusions. Estimates of cogeneration potential ranged from under 200 megawatts to over 2,000 megawatts. Many conclusions centered around the 300 to 600 megawatt range, but the conclusions of ten studies exceeded these estimates.

In its first power plan, in 1983, the Council estimated that 500 megawatts of cogeneration would be available to serve medium-high and high-demand forecasts. This was based on review of previous studies and comments received from participants in the regional planning process. The estimate used in the 1986 Power Plan was much more conservative, ranging from 130 megawatts in the low case to 320 megawatts in the high case. These estimates were derived from the results of a PNUCC utility customer survey that showed possible cogeneration of 510 megawatts at prices of 10 cents per kilowatt-hour or less.

The estimate of regional cogeneration potential used in this plan was derived through extensive studies involving Bonneville, PNUCC and utility and industrial work groups. These studies are described below.

The Bonneville-Techplan Study

Bonneville contracted with ADM Associates, Inc. in 1987 to begin an assessment of the cogeneration potential in the Pacific Northwest. Results of this assessment were presented at a seminar in May 1988. As a result of input received from this seminar, Bonneville contracted with a subcontractor of the ADM study, TechPlan Associates, Inc., to refine the methodology, update inputs, and make other changes in assumptions. The report on this study was released in March, 1989 (BPA, 1989a). A seminar was conducted on May 3, 1989, to present the methodology and findings of the report.

The results of the report, along with a preliminary list of issues was subsequently presented to Bonneville's Resource Program Technical Review Panel on May 18, 1989. This panel recommended that input be sought from utilities and industries regarding the assumptions used in the Bonneville/Techplan analysis. As a result of this recommendation, two work groups were formed, a Utility Cogeneration Work Group hosted by the Pacific Northwest Utilities Conference Committee (PNUCC), and an Industry Cogeneration Working Group hosted by Bonneville. Both of these working groups produced recommendations for further analysis. The work of these groups played an important role in defining issues and framing subsequent Bonneville and Council analyses.

The Utility Working Group consisted of representatives of both investor-owned and publicly owned utilities in the Northwest. The group undertook two tasks. First, it agreed to review the methodology and assumptions of the Bonneville/Techplan assessment, and, second, it elected to prepare a compendium of regional utility experience and perspectives regarding cogeneration resources (PNUCC, 1990b). As a result of the first task, the group recommended developing a range estimate of regional cogeneration potential in order to reflect the uncertainty associated with fuel prices, regional economic activity, financial conditions, and application of different technologies. The group offered two cases to bound the range. These two cases--one aggressive, the other conservative--were defined by specifying three parameters used in the TechPlan model. The results of those cases are discussed later in this section.

The Industry Working Group consisted of representatives of pulp and paper, chemical, food, and petroleum industries, plus hospitals and federal government installations. In addition, industrial customers and independent developers were represented. The group's input was solicited on internal rate of return assumptions, oversizing of cogeneration facilities, fuel availability and cost over time, and industry response to sell-back prices. Input also was sought on specific assumptions used in the Bonneville/TechPlan analysis.

Results of the initial application of this model were released in March 1989 (BPA, 1989a). Comments resulting from the seminars and other public review, and findings of additional analysis were released in a follow-up report (BPA, 1989b). These results suggested significantly more potential for cost-effective cogeneration than most previous studies. Neither the Council nor Bonneville used these results directly. Instead TechPlan converted and installed the Cogeneration Regional Forecasting Model on the Bonneville and Council computer systems.

Bonneville and the Council staffs, with support from TechPlan, analyzed the conservative and aggressive cases recommended by the PNUCC Utility Working Group. In addition, the Council and Bonneville staffs developed base case assumptions to be used in producing a measure of central tendency for cogeneration supply, and to provide a basis for other sensitivity analyses. These analyses were discussed in the Council staff issue paper on cogeneration in 1989 and are reviewed in the following section. The results displayed in issue paper 89-45 were further modified to derive the supply estimated for this plan, as described in the final part of this section.

Bonneville and the Council used the TechPlan methodology as the basis for joint development of regional cogeneration supply curves for use in both Bonneville's 1990 Resource Program and this power plan. Because the method used is central to the development of supply curves, the following section includes an abbreviated description of the Techplan model, which is called the Cogeneration Regional Forecasting Model. The contractor report (BPA 1989a) contains more detailed documentation.

The TechPlan Cogeneration Regional Forecasting Model

Many of the previous estimates of cogeneration supply potential have been based on industry surveys. The TechPlan study differs in that it uses a micro-economic approach to evaluate cogeneration potential. It relies principally on a proprietary computer model called the Cogeneration Regional Forecasting Model. This model forecasts future circumstances and technology options available to a variety of potential cogeneration project sponsors. Evaluation of project economics is used to simulate the decisions that would be made with respect to project development. Estimates are developed for the numbers of facilities suitable for cogeneration installations across the Pacific Northwest and the energy potential of specific facility types is scaled up to derive total potentials for the region. Note that this approach is similar to that used by the Council and Bonneville for development of conservation supply curves. Both methodologies require a forecast of a diverse set of buildings or facilities, estimation of their energy use patterns, and simulation of decision-maker behavior.

In the Cogeneration Regional Forecasting Model, the Pacific Northwest is divided into 23 subregions. These subregions were selected with consideration of electricity prices, climate zone, type of serving utility (consumer-owned or investor-owned), and the boundaries of the Bonneville service territory. Facilities that potentially could install cogeneration equipment are grouped into 25 types. The groupings are based on similarity of energy use patterns. Eleven of the facility types are industrial plants, the remaining fourteen are commercial facilities. Each of the facility types is further broken down into four typical size categories. The combination of subregions, facility types, and facility sizes yields 2,300 separate facility types that are evaluated for cogeneration potential. The model includes a data base of the estimated current number of existing commercial and industrial facilities that fall into each of these 2,300 categories. In addition to the number and type of facilities, representative energy use patterns, consisting of three electrical end-uses and eight thermal end-uses, are developed for each facility type within each subregion. These are differentiated seasonally and are assembled into load duration curves.

The model attempts to match a cogeneration technology with each of the 2,300 facility type combinations. The model has a set of representative technologies available to choose from, including reciprocating engine, combustion turbine, steam turbine, and combined-cycle combustion turbines. In all, there are 22 separate configurations of these basic technologies available within the model. Each has different capabilities with respect to electrical and thermal outputs, and the applications and modes of operation they are best suited for. Using assumptions regarding fuel prices and the price at which the facility could sell electricity back to the utility, the model performs a cost/benefit analysis for a subset of the configurations appropriate for each facility type. The objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return[10] to the project sponsor. For installations where it is profitable to sell all electricity generated back to the utility (i.e., where the electricity sell-back price is higher than the electricity rate paid by the facility) system size decisions normally are constrained by the minimum efficiency requirements specified by PURPA. (This parameter was modified for the estimates used in the Council's portfolio.)

When cogeneration systems have been matched for all of the facility type combinations, the results are scaled up by the expected number of facilities existing in the 20th year. Checks are made at this point to ensure that minimum present value savings and internal rates of return are attained. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. Assumptions are made about penetration (decisions to install the cogeneration equipment) at different levels of internal rates of return. Typically, the higher the internal rate of return, the greater the penetration. These penetration limits are used to reduce the economic potential to an achievable potential.

This entire procedure is run for various electricity sell-back prices (the price utilities will pay for cogenerated electricity), to produce a supply curve for cogeneration energy potential as a function of sell-back price.

Subsequent Analysis

Like most models, the Cogeneration Regional Forecasting Model requires several key assumptions. These assumptions are: 1) the price of cogeneration fuels, 2) the allowed electrical/thermal output ratio, 3) decision-makers' propensity to install cogeneration at different internal rates-of-return, and 4) industrial growth forecasts. Variations in these assumptions were used to construct a base case and high and low estimates using assumptions suggested by the PNUCC work group. In addition, assumptions were varied one at a time to test the model's sensitivity to each factor.

The Cogeneration Regional Forecasting Model was used to estimate cogeneration potential for four cases. The four cases are the TechPlan assumptions used in the May 1989 Bonneville report, the PNUCC utility working group aggressive and conservative cases and the base case set of assumptions developed by Council and Bonneville staff. These cases are summarized in Table 8-12.

In developing a set of assumptions for a base case, one of the important issues is fuel availability and cost. The TechPlan model relies on two principal fuel types for cogeneration installations. Wood residues are assumed to be the principal fuel used in the wood products and paper industries. Natural gas is the fuel for virtually all other facilities. Currently there are no provisions in the TechPlan model for constraining fuel supply for either of these fuel types. However, adjustments can be and were made to model results to reflect fuel supply limits.

10./ Internal rate of return is defined as the discount rate that causes the present value of project savings to equal the present value of project costs. It is commonly used as a measure of economic attractiveness in investment decisions.

Natural gas prices for the base case were set to firm contract levels used in the Council's 1989 supplement. These begin at $3.61 per million Btu in 1988 and escalate at about 1.9 percent per year more than general economic inflation. They reach $5.20 by 2010 in 1988 dollars. Wood residue fuel prices start at low levels, $0.70 per million Btu, but escalate rapidly in the latter half of the forecast period, reflecting growing competition for the fuel and increased shares of more expensive logging residues relative to mill residues. The wood residue assumptions were based on the analysis of the availability and cost of biomass resources described in the Biomass section of this chapter.

The base case uses an electrical/thermal output ratio of 50/50. This assumption is intended to represent approximate thermal balance with some amount of oversizing to allow for growth in facility thermal energy use patterns or other factors that may make oversizing regionally cost-effective in specific applications.

Another important assumption is the relationship between the decision-makers' propensity to install a cogeneration facility and the perceived economic benefits of the decision. As mentioned previously, the TechPlan model requires a relationship defining penetration as a function of internal rate-of-return. There appears to be very little empirical data on this subject and, to date, the public review process has provided only qualitative input. The base case assumptions (see Table 8-12) reflect the assumptions used by TechPlan, and those recommended by the PNUCC Utility Working Group. Where those assumptions diverge, a central tendency has been used. An upper limit on penetration of 85 percent of the potential was chosen, because it corresponds to the limit assumed for conservation penetration.

Table 8-12
Analytical Assumptions

	Case			
	TechPlan	PNUCC Conservative	PNUCC Aggressive	Council/BPA Base
Electrical/Thermal Output Ratio Limit	95/5	33/67	60/40	50/50
Fuel Price ($/MMBtu)				
Natural Gas[a]	$2.50/4.50[b]	$3.61	$3.16	$3.61
Biomass[c]	$0.70	$0.70	$1.50	$0.70

Penetration Rates vs.
Internal Rate of Return (%)

IRR	TechPlan	Conservative	Aggressive	Base
0	0	0	0	0
5	0	0	0	0
10	5	5	15	10
15	10	10	25	15
20	15	15	35	20
25	20	20	45	30
30	40	40	50	45
35	80	60	60	60
40	95	80	80	85

[a] Gas price series as described in discussion of backing-up nonfirm hydropower.
[b] Large user/small user prices.
[c] Biomass fuel price not to exceed the price of natural gas during the period of the study.

The results of this analysis are shown in Figure 8-7. The figure plots achievable potential as a function of electricity sell-back price. The energy values represent the amount of energy that would be available by the end of the 20-year planning period. The electricity sell-back prices shown are nominal levelized cents per kilowatt-hour and are expressed in January 1990 dollars.[11]

The results show a large variation in achievable cogeneration potential. At a sell-back price of about 12 cents per kilowatt-hour, the estimated potential ranges from 1,350 megawatts in the PNUCC conservative case to 9,700 megawatts using

11./ The Cogeneration Regional Forecasting Model was operated in January 1990 dollars, with the understanding that the price year of the draft plan would be 1990. Because of an oversight, discovered only as the final draft plan was being prepared, the cogeneration costs used in the analysis of the resource portfolio are in 1990 dollars, though other resource costs are in 1988 dollars. This discrepancy will be corrected in the final plan when all resource costs are adjusted to 1990 dollars. Reference energy costs of Table 8-1 are all 1988 dollars.

the TechPlan assumptions. The PNUCC aggressive case shows a potential of 5,100 megawatts, and the Council/Bonneville base case predicts 3,300 megawatts. At a sell-back price of 7.0 cents nominal, which is about comparable to the long-term avoided cost used in the Council's 1986 Power Plan, the range is from 0 megawatts to 1,550 megawatts. This compares to a range of 130 to 320 megawatts identified in the 1986 plan for cogeneration potential.

Cogeneration Potential

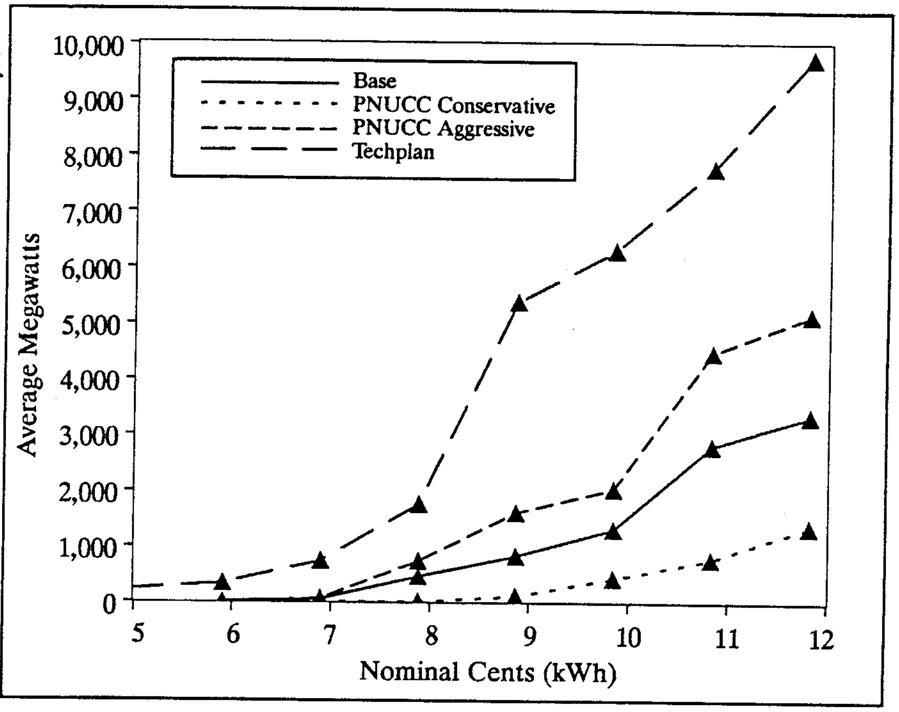

Figure 8-7
Cogeneration Potential under Alternative Assumptions with no Biomass Constraints

In addition to the above analysis, sensitivity tests were performed on a number of variables. These studies demonstrated that variations in key assumptions could cause swings of over 3,000 average megawatts in the estimated cogeneration potential. The amount of allowed oversizing and decision-makers' propensity to invest in cogeneration had substantial potential to increase cogeneration resource estimates. The price of cogeneration fuels, however, carried more potential for decreased estimates. These sensitivity studies are described in detail in the Cogeneration Resources issue paper.

These estimates were adjusted based on public comment received on the Cogeneration Resources issue paper and the final Council assumptions regarding the cost and availability of biomass fuels. The principal change related to the likely limited availability of low-cost biomass fuels. The mean biomass fuel availability was estimated to be 10 trillion Btu per year from mill residues and 15 trillion Btu per year from logging residues. Of this total, 19 trillion Btu were assumed to be available for cogeneration. (See the biomass section of this chapter.) This limits cogeneration from biomass fuels to 480 average megawatts, instead of the 1,600 megawatts estimated to be available in the unconstrained base case analysis. As a result, the adopted base case achievable cogeneration potential at 11.8 cents per kilowatt-hour is 2,200 average megawatts, consisting of 480 megawatts of biomass-fired cogeneration in the paper and wood products industries and 1,720 megawatts of gas-fired cogeneration in other sectors (see Table 8-13).

Table 8-13
Achievable Cogeneration Potential (MWa)
(1990 Dollars)

Sell-back Price (cents/kWh)	Base Case	Conservative Case	Aggressive Case
5.9	0	0	0
6.9	38	0	53
7.9	448	0	522
8.9	515	99	526
9.9	536	415	899
10.8	1,663	592	3,341
11.8	2,200	692	4,017

The estimated upper bound of achievable cogeneration includes about 4,020 megawatts of cogeneration at a sell-back price of 11.8 cents per kilowatt-hour, or less. This amount consists of 480 megawatts of biomass-fired cogeneration (limited as in the base case), and about 3,540 megawatts of natural gas-fired cogeneration. The lower bound of achievable cogeneration comprises 480 megawatts of biomass-fired cogeneration and about 210 megawatts of natural gas-fired cogeneration for a total achievable potential of 690 megawatts at 11.8 cents per kilowatt-hour or less.

As discussed in the biomass section of this chapter, an additional 43 trillion tons (annually) of biomass fuels may become available for cogeneration use. This amount of biomass fuel would increase the estimated contribution of biomass-fired cogeneration to about 1,140 megawatts in the conservative case (for a total of about 1,350 megawatts of cogeneration). The biomass-fired cogeneration would increase in the base case to about 1,570 megawatts, for a total of about 3,290 megawatts of cogeneration. In the Aggressive case, biomass fuel availability would again constrain the economic development of biomass-fired cogeneration to about 1,570 megawatts, for a total cogeneration potential of about 5,100 megawatts. As described in Volume II, Chapter 1, the Council plans to identify actions that might be taken to expand the availability of biomass fuels.

The adopted base case supply curve for cogeneration and upper and lower bounding curves (from the PNUCC Aggressive and Conservative cases, respectively), are shown in Figure 8-8.

Cogeneration Supply Curve

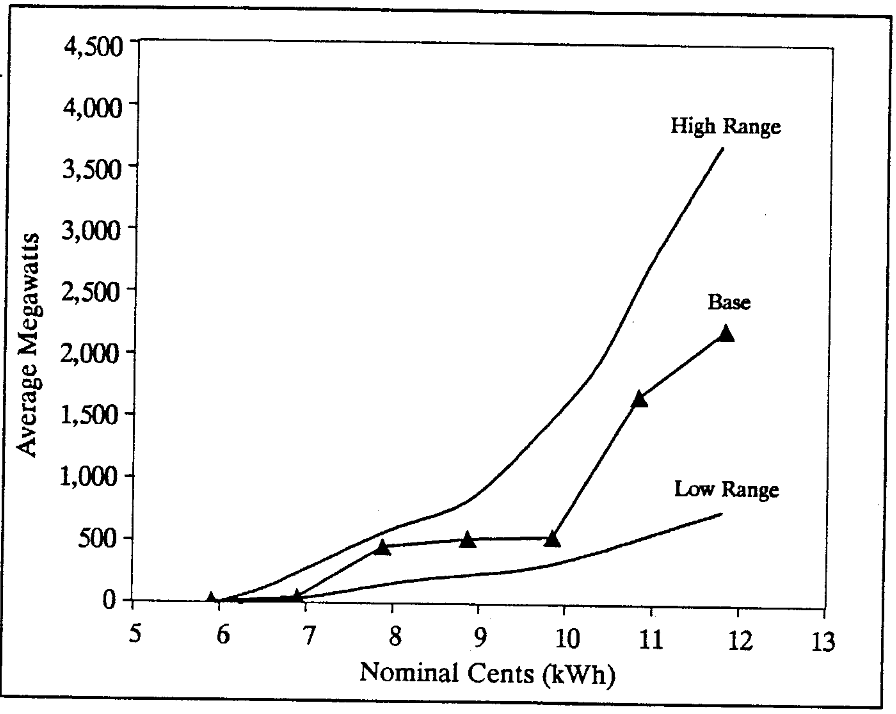

Figure 8–8
Cogeneration Supply Curve and Range with Constrained Biomass Availability

Planning Assumptions

For the purposes of resource portfolio analysis the cogeneration resource was split into four blocks, reflecting different fuels and costs. The first block contains 480 average megawatts of energy at an average levelized nominal cost of 7.5 cents per kilowatt-hour. This block is primarily biomass-fueled cogeneration in the wood products industries. The second through fourth blocks are gas-fired cogeneration, primarily in the petrochemical, hospital and institutional sectors, ordered by increasing cost. The second block contains 57 average megawatts at an average cost of 7.6 cents per kilowatt-hour, the third block contains 1,126 average megawatts at an average cost of 10.3 cents per kilowatt-hour, and the fourth block contains 537 megawatts of energy at an average cost of 11.3 cents per kilowatt-hour. The cogeneration planning assumptions are summarized in Table 8-14.

The alternative cases and the sensitivities to specific assumptions indicated that there is substantial uncertainty about the extent of the cogeneration resource. Therefore, a range of cogeneration uncertainty was specified for resource portfolio analysis. This uncertainty was based on the results of the cogeneration supply analysis using the PNUCC conservative and aggressive case assumptions.

As discussed in the introduction to this chapter, when resources are developed by someone other than a utility, the issue of risk-sharing arises. In evaluating the economics of utility-constructed resources, including conservation and generating resources, the Council attempts to use a set of consistent economic assumptions in cost comparisons. These assumptions imply a consistent allocation of investment risk between the resource developer and the region's ratepayers. In this way, all resources are placed on an equal footing for cost comparison.

However, the cogeneration supply curves that are generated using the TechPlan model express potential not as a function of direct cost, but as a function of the price that cogeneration developers would ask for electricity. In cases where cogeneration sponsors desire to earn rates of return that are higher than those implied in the financing assumptions for other resources, the cost of cogeneration may be overstated with respect to other resources. Though the prices developed by use of the model represent the prices that utilities may have to pay for cogenerated electricity from independently owned facilities, the actual costs of cogeneration borne by society may be somewhat less than those measured by the electricity sell-back price. Additional return to the facility is a transfer payment from consumers of electricity to the facility owners in return for assumption of risk associated with resource development and operation.

Conclusions

Cogeneration is a proven resource as manifested by its historical role and its recent resurgence. Its future role is largely a matter of economics and electric system policies that might be established to promote fuel diversity. There is already a significant amount of cogeneration capacity installed in Northwest industries, but much of it is not being used because of the availability of low cost and reliable electricity from the region's utilities. The region's mix of industries, including large concentrations of pulp and paper, petrochemical plants, food processing, and lumber, represent significant potential for cogeneration.

Previous Council plans included very limited amounts of cogeneration, but suggested further study of its potential. Bonneville has been doing those studies over the past few years. Although further refinement of the analytical methods continues, joint forecasts of cogeneration potential by Bonneville and Council staff show that cogeneration could meet a much more significant share of the region's future electricity needs than has been assumed in past Council plans.

The amount of cogeneration potential depends on future avoided costs. California experience has shown that if attractive prices are offered, a great deal of cogeneration can be developed. The base case cogeneration supply curves adopted for this plan indicate that if cogenerators were offered 6.9 cents per kilowatt-hour levelized nominal price for cogenerated electricity (roughly equivalent to current avoided costs) only about 40 megawatts could be expected to be developed. However, if cogenerators were offered 9.9 cents per kilowatt-hour for the power they generate, the amount developed would increase to about 540 megawatts under base case conditions and nearly 900 megawatts under more aggressive assumptions.

Table 8-14
Cogeneration Planning Assumptions
(1990 Dollars)

	Cogen 1	Cogen 2	Cogen 3	Cogen 4
Total Capacity	600	71	1,408	671
Total Firm Energy (MWa)	480	57	1,126	537
Unit Capacity (MW)	25	10	10	10
Seasonality	None	None	None	None
Dispatchability	Must-run	Must-run	Must-run	Must-run
Siting and Licensing Lead Time (months)	24	24	24	24
Probability of S&L Success (%)	80	80	80	80
Siting and Licensing Shelf Life (years)	5	5	5	5
Probability of Hold Success (%)	90	90	90	90
Construction Lead Time (months)	24	24	24	24
Construction Cash Flow (%/year)	a	a	a	a
Siting and Licensing Cost ($/kW)	a	a	a	a
Siting and Licensing Hold Cost ($/kW/year)	a	a	a	a
Construction Cost ($/kW)	a	a	a	a
Fixed Fuel Cost ($/kW/year)	a	a	a	a
Variable Fuel Cost (mills/kWh)	a	a	a	a
Fixed O,M&R Cost ($/kW/year)	a	a	a	a
Variable O&M Cost (mills/kWh)	a	a	a	a
Earliest Service	1994	1994	1995	2003
Peak Development Rate (units/year)	5	25	25	25
Operating Life (years)	20	20	20	20
Variable Energy Costs (cents/kWh)[b]				
Levelized Real	3.8	3.9	5.3	5.8
Levelized Nominal	7.5	7.6	10.3	11.3

a Siting, construction and operating costs are omitted from this table, because total energy prices from the cogeneration regional forecasting model (shown as energy costs) were used for costing this resource.

b The Cogeneration Regional Forecasting Model was operated in January 1990 dollars; it included the understanding that the price year of the draft plan would be 1990. Because of an oversight discovered only as the final draft plan was being prepared, the cogeneration costs used in the analysis of the resource portfolio are in 1990 dollars, although other resource costs are in 1988 dollars. This discrepancy will be corrected in the final plan when all resource costs are adjusted to a 1990 price year. Reference energy costs of Table 8-1 are all 1988 price year.

The base case estimate of 2,200 megawatts represents a cautious planning assumption, even though it is significantly increased from previous Council assumptions. Two pieces of information may put it into perspective. In PNUCC's *Northwest Regional Forecast*, (PNUCC, 1990a), utilities have identified 650 average megawatts of assured or planned new cogeneration. A PNUCC survey of least cost plans shows that cogeneration is an important resource in utilities' plans for the long term.[12] In response to a competitive bid solicitation, Puget Sound Power and Light received bids for 22 different cogeneration projects with a total capability of 1,112 average megawatts. Cogeneration has significant potential as an electricity resource and offers substantial benefits from an overall energy efficiency and environmental standpoint, if appropriate environmental controls are installed.

Several issues require resolution to facilitate the development of cost-effective and environmentally acceptable cogeneration. First, cogeneration, to a great extent, will be an independently developed resource. It is important that acquisition procedures for independently developed resources be developed and tested by utilities expecting to need new resources.

Opportunities for cogeneration are where you find them. Utilities having potential host facilities for cogeneration in their service territories should adopt policies and procedures for wheeling cogenerated power to utilities needing this resource. However, the prospect of a utility losing sales to a potential cogenerator who would sell to another utility (i.e., a firm that would develop cogeneration meeting its own electrical needs, and providing a surplus to sell to a utility) may be a powerful disincentive for cooperation regarding wheeling.

Experience in other regions suggests that large amounts of natural gas-fired cogeneration might become economically attractive once certain avoided cost levels are attained. This analysis suggests that this level is about 10 to 11 cents per kilowatt-hour in the Northwest. Oversizing might become very attractive at this price. To limit risk associated with future natural gas price uncertainty, and to maximize fuel-use efficiency, the Council recommends that natural gas-fired cogeneration be limited to approximately 1,700 megawatts at this time. Moreover, the Council recommends that gas-fired cogeneration plants generally be designed to thermal-electric balance. In the several years until avoided costs rise to 10 to 11 cents per kilowatt-hour in the Northwest, methods of managing resource diversity, and strategies for encouraging cogeneration thermal-electric balance, where desirable, need to be developed.

Cogeneration provides a cost-effective and highly efficient means of using biomass fuels. However, there is great uncertainty regarding the future price and availability of these fuels. Although apparently available in great quantity, certain forms of biomass, such as forest and agricultural residues, currently are not used to any extent as fuels. The price and availability of these materials should be investigated more thoroughly.

Although it is likely that federal emission control regulations gradually will be tightened for small-scale dispersed generating facilities, central-station power plant emission control requirements currently are more stringent than those for dispersed small-scale plants. State and local regulations should be reviewed and upgraded to ensure that distributed, small-scale plants are subject to levels of emission control comparable to central-station plants. Certain performance standards perhaps should be more stringent for cogeneration, because this is a distributed resource and more likely to be developed near population centers.

12./ See PNUCC, 1990b, p. 16.

Finally, in some circumstances, cogeneration may compete with more cost-effective end-use efficiency improvements. Implementation of one may render the other not cost-effective. Resource acquisition programs should ensure that opportunities for end-use efficiency improvements are explored whenever cogeneration is considered, and that the most cost-effective of the two resources is developed.

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Geothermal Power[13]

Geothermal resources are the usable heat of the earth. This heat, contained in both rocks and fluids, can be extracted for direct space, water or process heating applications, or to generate electricity.

The Pacific Northwest's first commercial use of geothermal energy commenced with construction of the Warm Springs Heating District in Boise, Idaho in the early 1890s. However, the resource there and elsewhere in the United States remained more a novelty than a significant energy resource until the 1960s when geothermal energy was first used to produce electricity at The Geysers in northern California.

Interest in geothermal energy grew through the 1970s with passage of the Geothermal Steam Act of 1970 (P.L. 91-581), the Arab oil embargo of 1972-74, the development of the Federal geothermal leasing program and passage of the Federal Geothermal Energy Research, Development and Demonstration Act of 1974 (P.L. 93-410). The U.S. Geological Survey took the lead role in resource identification and published this information in USGS Circulars 726 and 790 (Muffler, 1979). These circulars identified promising geothermal areas for the United States. By the mid-1970s, numerous state and federal programs were in place to assess geothermal resources of the United States and to aggressively encourage exploration and development. Geothermal interest remained high through the late 1970s and early 1980s due to increasing oil prices, market creation resulting from the Public Utility Regulatory Policies Act of 1978 (PURPA; P.L. 95-617), and a second major oil shortage in 1979.

By 1981, major changes began to occur. At the national level, oil prices stabilized and interest in renewable energy waned. In the West, continued development of geothermal resources in California and Nevada reflected a strong growth in California energy demand, active implementation of PURPA by state regulators, favorable state and federal tax provisions and an abundance of venture capital. But in the Northwest, projected power deficits were replaced by forecasts of prolonged surplus and low, stable rates, dashing the hopes of developers that rising regional electrical prices would create a profitable market for geothermal energy. Incentives for exploration vanished.

In its 1986 Power Plan, the Council found that generation of electric energy using the geothermal resources of the Pacific Northwest potentially could be cost-

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13./ Much of the background information and analysis in this section was taken from an issue paper prepared for the Council by John D. Geyer of John Geyer and Associates, through a contract with the Washington State Energy Office. This paper appeared as Council Staff Issue Paper 89-36, *Geothermal Resources*, October 16, 1989. The Northwest Power Planning Council appreciates the assistance that it has received from the Washington State Energy Office in support of the assessment of geothermal resources for this plan.

effective. But because the resource had not been confirmed, it was not included in the portfolio of the 1986 Power Plan.

To reduce uncertainties regarding the feasibility of using Northwest geothermal resources to generate electric power, the 1986 Action Plan called on Bonneville to complete design of the geothermal confirmation program called for in the 1983 power plan. Bonneville, in its 1990 Resource Program, proposed a geothermal confirmation program to be jointly undertaken between Bonneville and other interested utilities. Bonneville's proposed confirmation program is consistent with the recommendations of the Council's Research, Development and Demonstration Advisory Committee. The recommendations of the RD&D Advisory Committee are described in Volume II, Chapter 16.

Geothermal Technology

Four types of geothermal power conversion systems are in common use. These are dry steam, single-flash, double-flash, and binary-cycle power plants. The selection of technology for a specific application is sensitive to geothermal fluid phase (i.e., dry steam or water) and temperature.

Dry steam reservoirs occur rarely but are the simplest to exploit for electrical generation. This was first done at Lardarello, Italy, in 1904. The United States' geothermal industry began when dry steam was harnessed at The Geysers in 1955. The Geysers remains the only commercial dry steam field in this country. The basic design (see Figure 8-9) involves directing the steam from naturally flowing dry steam wells through a rock catcher,[14] then directly into a turbine. A condenser is used to create a vacuum at the turbine exhaust to increase efficiency. Mechanical-draft cooling towers normally are used for condenser cooling. Condensate is returned to the reservoir using injection wells. The thermodynamic efficiency of dry steam plants is near 50 percent.

14./ A rock catcher is a strainer designed to capture solid debris in the geothermal steam.

Dry Steam Power Plant

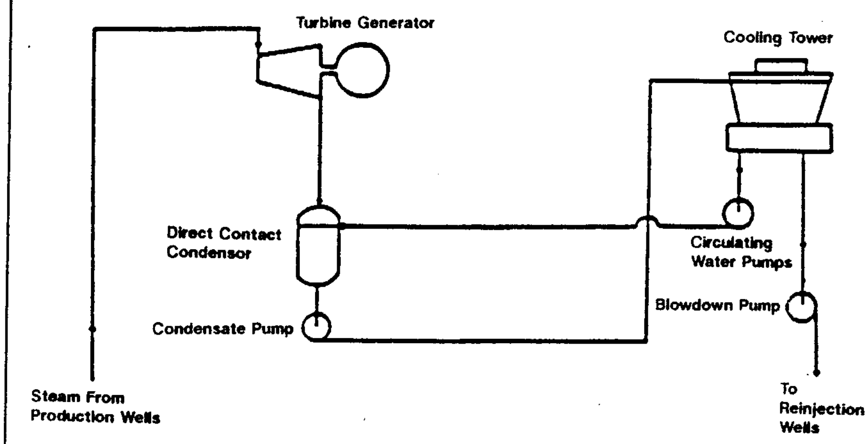


Figure 8–9
Schematic Diagram of a Dry Steam Geothermal Power Plant

Single-flash power plants (see Figure 8-10) are designed for hot water reservoirs above 220°C (425°F). High-temperature reservoir water flows to the surface via wells and is directed into steam separators. Lower pressure maintained within the separator allows a portion of the hot water to flash into steam. In most systems, this amounts to about 15 to 20 percent of the water. The flashed steam is directed through scrubbers, to the turbine and thence to a condenser. Residual liquid from the separator, together with condensate, is returned to the reservoir by injection wells. The condenser normally is cooled by cooling towers. The thermodynamic efficiency of a single-flash plant is about 35 percent.

Single–Flash Power Plant

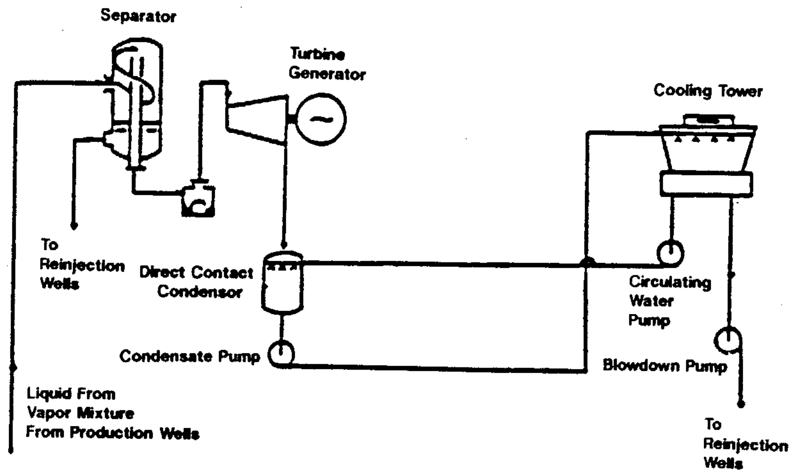
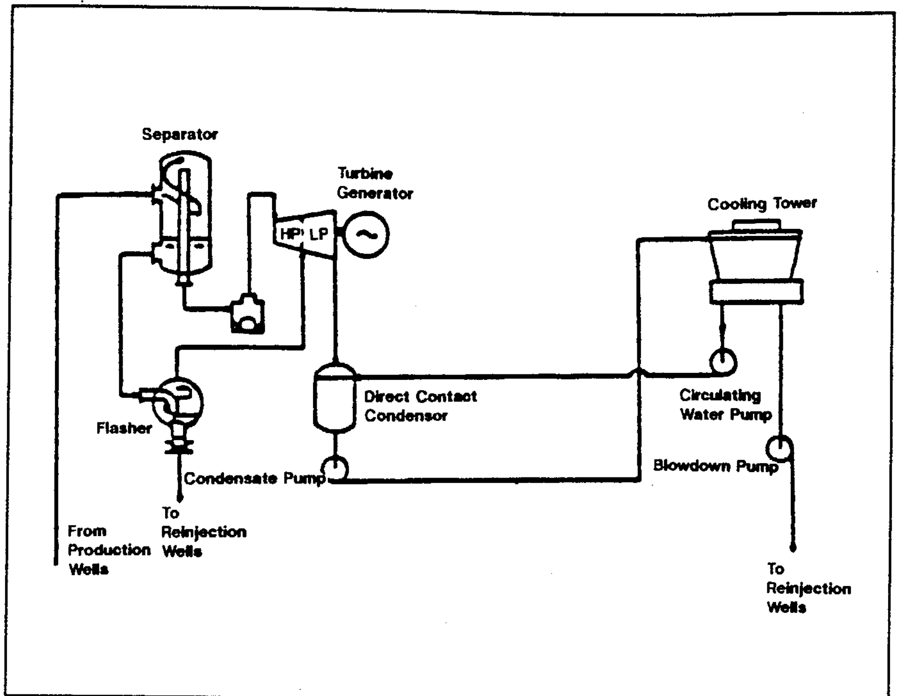


Figure 8–10
Schematic Diagram of a Single–Flash Geothermal Power Plant

Double-flash plants (see Figure 8-11) are designed for hot water reservoirs having temperatures of 150°C (300°F), and above. These plants are similar to the single-flash systems, except they incorporate a second-stage separator where the residual fluid from the first-stage separator is flashed again at a lower pressure. This second stream of lower-pressure steam is directed into either a low-pressure stage of a compound turbine or a separate low-pressure turbine. Residual liquid from the second-stage separator and the condensate are returned to the reservoir using injection wells. Double-flash plants have a thermodynamic efficiency of about 40 percent.

Double–Flash Power Plant

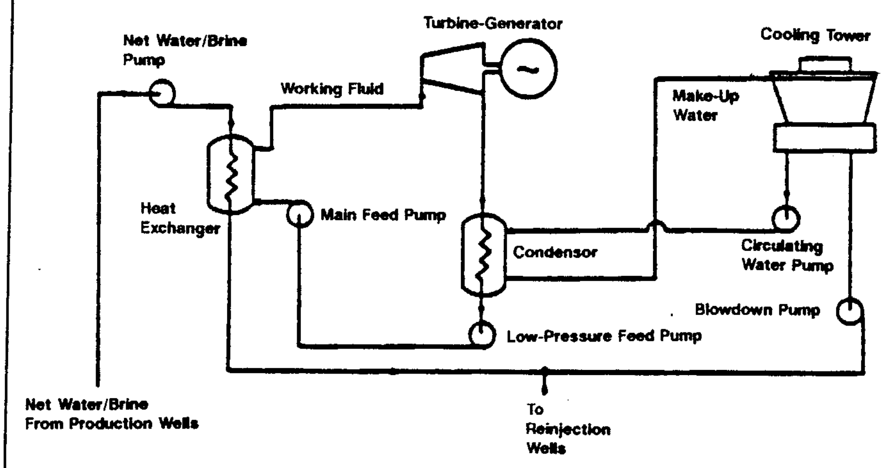
Figure 8–11
Schematic Diagram of a Double–Flash Geothermal Power Plant



Binary-cycle power plants (see Figure 8-12) are used for low-temperature geothermal fluids, generally below 193°C (380°F). These plants use separate, closed geothermal fluid and working fluid loops (hence the name "binary"). The geothermal fluid loop consists of production wells equipped with downhole pumps that circulate geothermal fluid through heat exchangers. Here heat is transferred to a working fluid having a low boiling point, such as isobutane or freon. Once the useful heat has been extracted, the geothermal fluid is returned to the reservoir using an injection well. The vaporized working fluid is used to turn the turbine, then is discharged to a condenser. A feed pump returns the condensed working fluid to the heat exchanger.

Binary Power Plant

Figure 8–12
Schematic Diagram of a Binary Geothermal Power Plant



Binary plant components often are modular in design and lend themselves to factory pre-fabrication. Thus, they usually can be installed rapidly at relatively low costs. The thermodynamic efficiency of binary plants is lower than for other designs, partly because the internal load for pumps and auxiliary equipment is higher. For certain geothermal resources, however, binary plants may provide the most efficient use of the resource in terms of net power per unit mass of fluid. Small binary units are suited to wellhead tests, to low and moderate temperature geothermal resources, or to resources or locations where environmental factors preclude the use of other technologies.

Geothermal Development Issues

The principal issues associated with the development of geothermal resources in the Pacific Northwest include resource confirmation costs and risks, environmental impacts and land-use conflicts.

Resource Confirmation Costs and Risks

More than for most other resources, confirming the quantity and quality of a geothermal resource is a difficult, expensive and risky business. The resource is hidden and must be accessed and measured through expensive geologic exploration techniques, including costly thermal-gradient wells and production wells. Extensive exploration simply may confirm that a potential resource is not developable. Furthermore, the characteristics of geothermal fluids at a new area cannot be inferred easily from experience at apparently similar resource areas. Although the general potential for producing useful energy at a new location can be inferred from experience at areas of similar geology, extensive exploration within the new area is required to confirm its potential for geothermal development.

Environmental Effects

The key environmental concerns resulting from geothermal development are the release of hydrogen sulfide, disposal of geothermal fluid, noise, and impacts on fish and wildlife habitat.

Hydrogen sulfide is a non-condensable gas apparently present to some degree in all geothermal fluids. The major concern regarding hydrogen sulfide is its effect on human health. At low concentrations, hydrogen sulfide has an offensive rotten eggs odor. At high concentrations, hydrogen sulfide has virtually no odor, but it is toxic and can cause death quickly by respiratory paralysis. If present, some releases may occur during well development and testing. Hydrogen sulfide releases are controlled during power plant operation by collection and reinjection of non-condensable gasses.

Geothermal fluids may be contaminated naturally with toxic materials. Contamination of fresh water aquifers and surface water by geothermal effluent must be avoided. Disposal must be tailored to the specific geothermal site. The preferred option for disposal is reinjection of geothermal fluids to the reservoir. Reinjection of geothermal fluids is practiced at contemporary U.S. geothermal developments. Reinjection presents the added advantage of maintaining reservoir fluid levels.

Geothermal drilling can cause noise pollution in the immediate vicinity of the wells. There is also a great deal of noise when wells are vented to the atmosphere during development and testing, and when a plant is shut down. Control of noise has not received much attention to date, and significant improvements probably could be made at low cost.

Most geothermal sites are in relatively isolated locations, some of which may be ecologically sensitive. Exploration, drilling, construction and operation may involve 1,000 to 2,000 acres for a 50-megawatt plant. Though a relatively small proportion of this area is physically disturbed for construction, wildlife habitat impacts may be more widespread because of noise and human presence.

Secondary pollution of water and land can result from deposition of some materials released by geothermal plants. Drift deposition of pollutants can cause acidification of lakes and streams and can introduce toxins such as arsenic and boron into water. Geothermal plants may be located in arid or semi-arid regions where water used on-site, such as for condenser cooling, may be a scarce and valuable resource for fish and wildlife. Water consumption may be reduced by use of dry cooling towers.

Land Use Conflicts

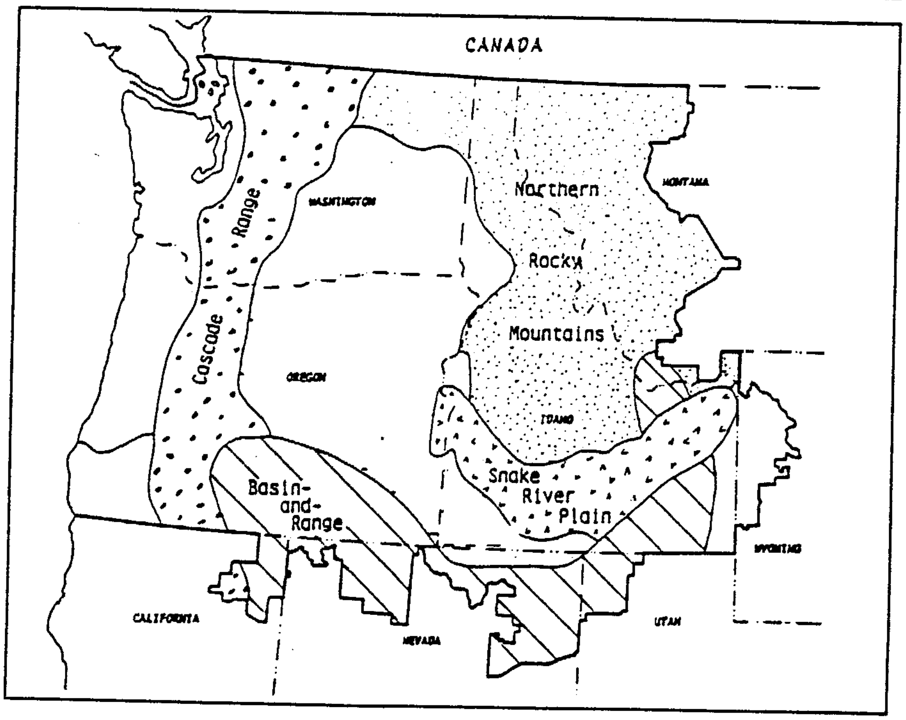
Many of the most promising Northwest geothermal resource areas are located within or near lands of great environmental or aesthetic value. For example, the geothermal resources of the Cascade Mountains are related to the presence of volcanic activity. Volcanic features, however, often are the focus of national parks, monuments, wilderness areas or recreational areas. The potential for land use conflict is obvious. Geothermal development, an industrial activity, near these sensitive areas must be controlled to avoid unacceptable land use conflicts.

Geothermal Potential in the Pacific Northwest

The Pacific Northwest has three geologic provinces with the potential to produce significant quantities of useful geothermal energy.[15] These provinces are the northern Basin-and-Range, the Cascade Mountain Range, and the Snake River Plain (see Figure 8-13). The Oregon-Washington lava plateaus, the Yellowstone region and parts of the northern Rocky Mountains also may have some geothermal potential.

Structural Provinces

Figure 8–13
Structural Provinces of the Pacific Northwest



15./ A geologic province is an extensive region of similar geologic structure and history, within which there may be one or more geothermal fields. Different geothermal fields within a single province may share similar physical and chemical characteristics. This is because the primary reason for their existence (volcanism or deep faults) is similar.

The Basin-and-Range province has a general absence of volcanic or intrusive heat sources. In this province, high-temperature geothermal systems are created by deep fluid circulation along faults in areas of high-conductive thermal gradients. Geothermal energy production has been demonstrated at Basin-and-Range sites in Nevada and Utah.

The Cascade Range has a long history of volcanism, continuing into the present. The most recent volcanic heat sources of this province exist along the eastern margin of the range and at the major volcanic peaks. Here, relatively shallow magmatic bodies are thought to provide heat sources for overlying geothermal fluids. Cold water from precipitation percolates downward and masks most surface manifestations of the Cascades resources.

By prevailing theory, no active magmatic heat source is believed to remain beneath the Snake River Plain itself; thermal features located here are believed to remain from past magmatic influence, which is now manifest to the east at Yellowstone National Park. But drilling records show that residual moderate temperature resources greater than 150°C (300°F) are widespread, though none greater than 205°C (400°F) (GeothermEx, Inc., 1987).

Promising Geothermal Resource Areas of the Northwest

The period from 1981 to present has been marked by sporadic efforts to model geology and discover reservoirs at the most promising Northwest sites. Northwest achievements during this period include issuance of leases on Federal lands, discovery of fluid temperatures of 265°C (510°F) at 940 meters (3,057 feet) at Newberry Volcano, Oregon, in a U.S. Geological Survey test hole, and discovery of fluids well in excess of 205°C (400°F) in several privately drilled holes at Medicine Lake, California. These sites are potentially attractive for power generation by flash-steam technology. There are no estimates of field reserves.

Other geothermal events of note during the 1980s, as compiled by GeothermEx, Inc. (1987) and others, include:

- Upward re-evaluation of probable reservoir temperature (at an unknown depth) at Klamath Falls, Oregon to 195°C (383°F) or higher.

- Promising temperature and fluid findings in private drillholes at the Alvord Desert, Oregon.

- Abandonment of federal R&D power generation efforts at Raft River, Idaho, in 1982 after only a few months of generation tests at about half the rated 5 megawatt capacity. Electricity production from geothermal fluids at temperatures under 150°C (300°F) was demonstrated, but commercial feasibility could not be established.

- Abandonment of efforts to generate power from geothermal resources at Lakeview, Oregon, without having demonstrated the commercial feasibility of the reservoir. This project suffered from fluid production problems, inadequate disposal mechanism and inability to negotiate a long-term power sales agreement.

- Progressively reduced levels of activity at exploration sites in Nevada, Oregon, Idaho and Montana in response to falling energy prices, shrinking markets for electricity, limited transmission line capacity, cessation of geothermal energy tax credits, and other changes in tax law.

- Major public involvement and education efforts in central Oregon. These resulted in increased awareness of the geothermal potential of central Oregon and initiatives for additional protection of Newberry Volcano and related features. The president recently signed a law designating the Caldera and nearby features including the Lava Cast Forest, the Northwest Rift Zone and Lava Butte as the Newberry National Volcanic Monument (P.L. 101-522). The Forest Service estimates that this designation will preclude about 65 percent of the estimated geothermal potential of the Newberry Caldera Known Geothermal Resource Area (KGRA) from being developed.

  Diagonal drilling will be allowed under a special area adjacent to the Monument, but no surface geothermal facilities will be allowed, and leases will not be let for any resource directly under the Monument. The surface of the special management area will be subject to the same regulations as the Monument. Earlier restrictions on geothermal development at Newberry include: 1) designation by the 1975 Oregon Legislature of the caldera and some adjacent areas as unsuitable for the siting of geothermal power plants of 25 megawatts or greater (House Joint Resolution 31, 1975 regular session); 2) declaration by the state Energy Facility Siting Council in 1975, modified in 1985, of the caldera and adjacent areas, generally consisting of the outer slopes of the caldera above 7,000 feet elevation, as "unsuitable for geothermal development"; and 3) prohibition, in the Final Land and Resource Management Plan of the Deschutes National Forest, adopted October 1990, of leasing of federal geothermal lands within the hydrologic boundary of the caldera (Collins, 1990).

- Concerns for protecting the thermal features within the national park system and opposition to drilling and development in the vicinity of Crater Lake National Park resulted in federal legislation to protect significant thermal features in National Parks and Monuments (P.L. 100-443). The passage of this legislation resulted in suspension of geothermal exploratory operations near Crater Lake National Park. The National Park Service funded scientific studies of possible thermal features at Crater Lake National Park. These raised media and public concern and new uncertainties about future geothermal development near Crater Lake and other sensitive areas.

- Three U.S. Department of Energy co-funded gradient holes at Newberry Volcano and near Mt. Jefferson, Oregon, reached below 4,000 feet, but data placed in public records failed to reveal significant temperatures or permeability. A private temperature gradient hole near Breitenbush Hot Springs, Oregon, reached 2,460 meters (8,000 feet) with a 135°C (275°F) aquifer at 760 meters (2,470 feet) and a maximum temperature of about 170°C (340°F). This hole has been plugged and abandoned.

- Discovery of 265°C (545°F) near 3,000 meters (10,000 feet) depth at Meager Creek, British Columbia, near Mt. Garibaldi, provided an important data point in the northern-most part of the Cascade Range and confirms the potential for high temperature discoveries throughout the Cascades.

Over three dozen areas have been drilled to significant temperatures or retained by industry with expressions of interest to proceed, subject to availability of a power sales market.

These activities prompt the following generalized observations on geothermal resources of the Pacific Northwest:

- Nowhere in the Pacific Northwest region has a high-temperature commercially-developable geothermal resource been confirmed to date. The only confirmed resource area (Raft River, Idaho) has perhaps 5 to 10 megawatts of proven reserves.

- Despite limited knowledge of the Cascade Range, the commercial generation potential is believed to be larger than that of the Basin-and-Range province, based on the Cascades' young volcanic history and spatial extent.

- A large geothermal resource may exist beneath the eastern end of the Snake River Plain; however, almost nothing is known about it. Development access and future exploration is barred by federal legislation due to the proximity of Yellowstone National Park.

- Exploration is much further advanced, and has been significantly more successful, in the Basin-and-Range province than elsewhere in the Pacific Northwest region. Exploration technology is less well developed for use in the other provinces.

- The best-understood geothermal field of the Cascade Range province is outside the Pacific Northwest Region, as defined by the Columbia River Basin and adjacent areas served by the Bonneville Power Administration. This is the Meager Creek area in British Columbia. A similar situation exists with respect to the Basin-and-Range province. Confirmed or currently developed Basin-and-Range sites include Medicine Lake, California, and Beowawe, Nevada, both located about 20 miles outside Bonneville's service boundaries, as well as several other sites in Nevada and in Utah.

- Nothing to date indicates that any of the Northwest resources will have unusual or troublesome geochemistry, or will present unusually difficult resource-related operating conditions. Access and climate may present challenges.

- Environmental and land use constraints on exploration and development are expected to be most severe in the Cascade Range and on parts of the eastern Snake River Plain. There are fewer constraints on development in the Basin-and-Range province. Access to geothermal areas probably will be more difficult in the Cascade region than elsewhere in the Pacific Northwest because of topography, climate, national wilderness area and national park designations, and possibly because of other land use restrictions.

- Because of better-developed exploration technology, the results of exploration to date, considerations of land use and access, and despite a probably smaller resource base, confirmation and commercial development is expected to proceed more rapidly in the Basin-and-Range province than elsewhere in the region. However, the remoteness of most of the Basin-and-Range province makes transmission access and interconnection costs critical aspects of confirmation activities.

In 1983, Bonneville contracted for a detailed regional geothermal assessment to consolidate and evaluate all geologic, environmental, and legal and institutional information and to apply a uniform methodology to the evaluation and ranking of potential geothermal sites within the Bonneville service territory. This "Four-State Study" (Bloomquist, et. al., 1985), identified a total of 1,265 potential geothermal resource sites. All sites were screened to eliminate those that had little or no chance of development because of inadequacies of resource temperature, legal prohibitions against development, or prohibitive economic conditions. Of the original 1,265 sites, 99 were selected for detailed analysis of electrical generation potential and 150 more were studied for direct use applications.

A methodology to rank the sites by energy potential, degree of developability and cost of energy was used to compare sites relative to each other and to indicate which sites possessed superior, average or inferior development potential and to identify areas requiring work. The best of these sites were used by the Northwest Power Planning Council in its 1986 Power Plan to forecast the supply of geothermal energy that could be available to the region over a 20-year planning horizon. The most promising sites have continued to receive industry attention, and their selection remains generally valid to date.

Table 8-15 describes the most promising Northwest geothermal sites and their estimated potential capacity and energy. The maximum amount of energy available from any one site is assumed to be 500 megawatts. Published estimates for some of these sites greatly exceed 500 megawatts, but, in general, more and better data yield smaller and more reliable estimates. Limiting the estimated energy available from any site to a maximum of 500 megawatts is believed to produce a more realistic estimate of regional geothermal potential.

The locations of the sites listed in Table 8-15 are shown on Figure 8-14. Note that Figure 8-14 shows all major geothermal resource areas in the Northwest. Development at several of the areas shown would be restricted or prohibited because of land-use or environmental conflicts.

In addition to the areas listed in Table 8-15, 30 additional locations were identified in the "Four-State Study" as having "good" or "average" development potential for more than 1 megawatt of capacity. The identification of these sites as promising remains valid although they lack recently expressed interest by industry. Together, these 30 additional sites are estimated to have 163 megawatts of potential capacity and 130 average megawatts of energy.

Table 8-15
Promising Northwest Geothermal Resource Areas

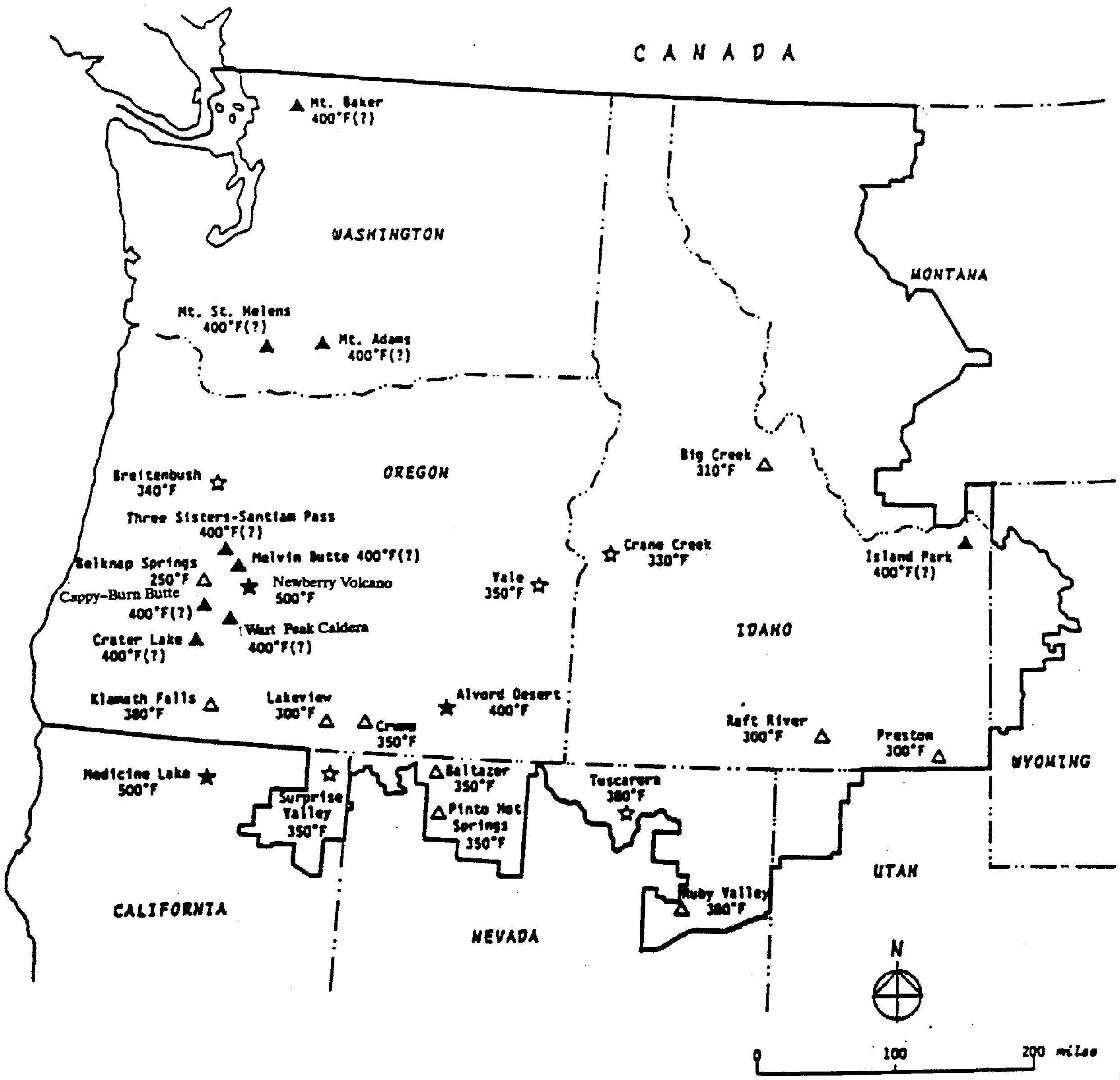
Resource/Potential Area	Geologic Province	Data Quality	Potential Capacity (MW)	Potential Energy (MWa)
High Potential for High Enthalpy Fluids				
Newberry Volcano, Oregon[a]	Cascades	High	311[b]	250+
Alvord Desert, Oregon	Basin-and-Range	Medium	118	95
Medicine Lake, California	Cascades	High	N/A	N/A
High Potential for Medium Enthalpy Fluids				
Surprise Valley, California	Basin-and-Range	High	25	20
Vale, Oregon	Basin-and-Range	Medium	163	130
Crane Creek, Idaho[a]	Basin-and-Range	Medium	224	179
Moderate Potential for High Enthalpy Fluids				
Crater Lake, Oregon	Cascades	Medium	500	400
Cappy-Burn Butte, Oregon[a]	Cascades	Low	473	378
Glass Buttes, Oregon[a]	Cascades	Low	348	278
Wart Peak Caldera, Oregon[a]	Cascades	Low	145	116
Melvin Butte, Oregon[a]	Cascades	Low	500	400
Bearwallow Butte, Oregon[a]	Cascades	Low	500	400
Mt. Baker, Washington	Cascades	Low	500	400
Mt. Adams, Washington	Cascades	Low	500	400
Moderate Potential for Medium Enthalpy Fluids				
Klamath Falls, Oregon[a]	Basin-and-Range	High	200	160
Klamath Hills Area, Oregon[a]	Basin-and-Range	Medium	300	240
Lakeview, Oregon	Basin-and-Range	Medium	10	8
Crump, Oregon	Basin-and-Range	Medium	79	63
Raft River, Idaho[a]	Basin-and-Range	High	15	12
Big Creek, Idaho[a]	Basin-and-Range	Medium	29	23

a Top sites from 1985 Four-State Study noted in 1986 Power Plan.
b Reduced 80 percent from 1986 Power Plan, due to land use restrictions.

Source: Four-State Geothermal Study and GeothermEx, Inc.

Geothermal Resources

Figure 8-14
Geothermal Resource Areas in the Pacific Northwest



High Potential for High-Enthalpy Fluids
High Potential for Medium-Enthalpy Fluids
Moderate Potential for High-Enthalpy Fluids
Moderate Potential for Medium-Enthalpy Fluids

Cite: GeoThermEx, 1987

Geothermal Power Plant Cost and Operating Characteristics

The estimated costs of electricity generation used in the Four-State Study were based on estimates by Bechtel National, Inc., using data from 32 plants designed or built prior to 1984. But major advances in plant design and costs from 1985 through 1989 have been documented in case studies by the Bonneville Power Administration, the Washington State Energy Office and the Oregon Department of Energy (Bloomquist, et. al., 1987, 1989). The findings of these more recent studies were used to update cost estimates for this plan.

The Northwest may anticipate first generation plants of 10 to 20 megawatts gross capacity currently producing 8 to 17 net megawatts of energy. These would occupy small (five-acre) sites, have minimal road access and possess high efficiency and reliability. Design standards likely would be modest as these pilot plants would be superseded by larger-scale plants if commercial development of the reservoir proved successful. Once reservoir capability and technical and economic viability are established, a quick jump likely will be made to larger plants. These can be built almost as fast, involve less capital per kilowatt, have greater reliability, and are eligible for utility acquisition. These will be commercial units of 50 +/- 20 megawatts capacity. Subject to internal and external variables, their capital costs may vary from minus-20 to plus-10 percent of pilot plant costs.

Table 8-16 portrays the low boundary and mid-range of 1989 industry capital costs. Note that Table 8-16 includes low boundary and mid-range costs for both flash and binary plant configurations. "As-built" costs cited in interviews and literature include interest during construction but seldom reflect financing fees or owner's costs other than interest. These may be $150 to $200 per kilowatt. Wellfield development costs on deep reservoirs average about 35 percent of plant costs. At $550 to $650 per kilowatt, $10 to $12 million would provide four or five production and two injection wells as well as piping and other surface equipment needed to serve a 20-megawatt plant. Total direct and indirect costs for a project (plant, financing, general and administrative, capitalized fuel supply and interconnection) could run from $2,200 to $3,000 per net kilowatt. A 20-megawatt pilot plant, therefore, represents a $38 to $50 million capital commitment.

Siting, permitting and financing will take 14 to 24 months (concurrent with early production drilling and testing), with a construction schedule of 16 to 36 months to follow. Total lead time ranges are 36 to 60 months, with 42 months a realistic goal. These and other non-cost characteristics of a typical geothermal power plant are shown in Table 8-17.

Table 8-16
Geothermal Plant Cost Components: Low and Mid-Range
(1990 Dollars)

	Low Case	Mid-Range Case
Siting and Licensing Costs ($/kW, net)		
Land Options	Federal lease	Federal lease
Easements and Right-of-Way Acquisition	Federal lease	Federal lease
Owner's Costs During Siting and Licensing	$40	$40
Geotechnical Surveys	$10	$10
Environmental Impact Statement	$15	$15
Financing Costs ($/kW, net)	$80	$100
Construction Costs ($/kW, net)[a]		
Land Acquisition	Federal lease	Federal lease
Site Utilities and Services	$25	$25
Construction:[b]		
Materials	$625	$725
Labor	$600	$700
Engineering and management	$140	$200
Pre-production (Start Up)	$25	$30
Contingency Allowance	c	c
Owner's Costs During Construction	$90	$100
Switchyard	$10	$10
Transmission Interconnect to the Grid[d]	$40	$70
Spare Parts Inventory	$20	$30
Royalties	Federal lease	Federal Lease
Fuel Costs:[a]		
• If Wellfield Capitalized:		
Wellfield Capital ($/kW, net)	$550	$640
Wellfield O&M ($/kW/year)	$19.25	$22.40
• Commodity Costs, if Bought (mills/kWh)[e]	20.0	26.0
Operating and Maintenance Costs		
Fixed O&M costs ($/kW/year)[f,a]	$45	$53
Variable O&M costs (mills/kWh)	3[g]	3[g]
Consumables ($/kW/year)[a]	$10	$10
Interim Capital Replacement[a]	h	h
Decommissioning Cost ($/kW)[h]	$80	$80

a Values shown are for flash plants; 20 percent greater for binary.
b "Overnight" construction costs, exclusive of interest.
c Contingency allowance, 6 percent of capital cost is included in capital accounts.
d Grid interconnection costs are representative, assuming $110,000 per mile for a 115-kilovolt line serving 150 megawatts of capacity.
e Low case: $1.25 per 1,000 pounds steam at 16 pounds per kilowatt-hour. Mid-range case: $1.45 per 1,000 pounds steam at 18 pounds per kilowatt-hour.
f At 3.5 percent of capital costs, per year.
g Values shown are for flash plants; add 3 mills for binary.
h Wellfield replacement costs--$2 million every 5 years.
i Costs to plug and restore.

Table 8-17
Representative Geothermal Power Plant Non-Cost Characteristics

Type of Plant	Geothermal (direct, flashed or binary)
Rated Capacity	50 megawatts
Heat Rate	9,280 Btu per kilowatt-hour
Equivalent Annual Availability	90 percent
Seasonality	Negligible
Siting and Licensing Time	14 to 24 months; average 18 months
License Shelf Life	5 years
Construction Time	36 months for 50-megawatt unit 28 months for 25-megawatt unit 16 months for 10-megawatt unit
Operating Life	30 years

Reference Energy Cost Estimates

Reference energy costs were calculated for typical Basin-and-Range and Cascades geothermal power plants. The average costs of a mid-range binary and a mid-range flash plant (see Table 8-16) were chosen as representative of Basin-and-Range development. Mid-range flash plant characteristics were considered as representative of development in the Cascades.

The reference energy costs of these two representative plants are shown in Table 8-18. These costs are calculated using the reference financial and service date assumptions described in the introduction to this chapter. The plants are assumed not to be dispatchable, hence the capacity factor is equal to the plant availability factor of 90 percent (see Table 8-17).

Table 8-18
Reference Energy Costs for Representative Geothermal Power Plants (cents/kWh) (1990 Dollars)[a]

	Real	Nominal (30 year)	Nominal (40 year)
25-Megawatt Basin-and-Range Plant	4.1	7.2	8.1
50-Megawatt Cascades Plant	3.8	6.7	7.5

a The Washington State Energy Office assessment of geothermal was prepared in January 1990 dollars, with the understanding that the price year of the draft plan would be 1990. Because of an oversight discovered only as the final draft plan was being prepared, the geothermal costs used in the analysis of the resource portfolio are in 1990 dollars, although other resource costs are in 1988 dollars. This discrepancy will be corrected in the final plan when all resource costs are adjusted to a 1990 base year. Reference energy costs of Table 8-1 are all in 1988 dollars.

Because of the strong influence of site-specific conditions on the cost of power from a geothermal resource, actual energy costs from Northwest geothermal resources likely will vary considerably from site to site. Power plant and wellfield costs will vary according to fluid temperatures (and related thermal efficiencies) fluid chemistry, reservoir depth and the conversion technology used. Shown in Table 8-19 is a possible distribution of capital costs versus resource quantity for Northwest geothermal development. These estimates can be refined only by further exploration and preliminary engineering at specific sites.

Table 8-19
Possible Cost Distribution
Northwest Plant and Wellfield Development

Plant Characteristics	Capital Cost ($/MW)	Fixed O&M Cost ($/kW/year)	Variable O&M Cost (mills/kWh)	Estimated Potential (MWa)
< 15-Megawatt Plant Shallow Wells Good Access	< $1,600	64	5	50 MW
< 15-Megawatt Plant Deep Wells Good Access	$1,600	64	5	100 MW
15 to 50-Megawatt Plant Shallow Wells Good Access	$1,800	72	5	250 MW
15 to 50-Megawatt Plant Shallow Wells Remote	$2,000	70	5	400 MW
15 to 50-Megawatt Plant Deep Wells Good Access	$2,200	77	5	800 MW
15 to 50-Megawatt Plant Deep Wells Remote	$2,400	84	5	1,000 MW
> 50-Megawatt Plant Deep Wells Good Access	$2,600	78	5	1,000+ MW
> 50-Megawatt Plant Deep Wells Remote	$2,800	84	5	1,000+ MW

Availability of Northwest Geothermal Resources for Development

Basin-and-Range Resources

In the Northwest, electric power generation from Basin-and-Range geothermal resources has been demonstrated only at the Raft River site in southern Idaho. But to the south, in Nevada, several commercial geothermal power plants are operating from Basin-and-Range geothermal resources. The combined capacity of these plants is several tens of megawatts, and additional proven resources await a market.

Several promising Basin-and-Range sites have been identified within the Northwest (see Table 8-15). One site (Alvord Desert, Oregon) shows high potential for high-temperature fluids. Three others, Surprise Valley, California (within

Bonneville's service territory), Vale, Oregon and Crane Creek, Idaho show high potential for medium-temperature fluids. Basin-and-Range resources totaling 424 megawatts of energy are identified in Table 8-15 as having high technical potential for development. Basin-and-Range sites producing an additional 506 megawatts of energy are described as having a moderate potential for development. Given the high potential for commercially-developable geothermal resources at several sites, and the successful development of similar sites in Nevada, the Council is reasonably confident that some Basin-and-Range resources can be successfully developed in the Northwest. But with the limited information currently available, only crude estimates of achievable potential can be made at this time. Combining the full amount of "high potential" Basin-and-Range resource with 50 percent of the "moderate potential" resource (to allow for its lower probability) gives a possible Basin-and-Range technical potential of 677 megawatts. But, land use conflicts and environmental concerns will limit the extent to which this resource can be developed. Assuming that development of about half the Basin-and-Range technical potential is precluded because of land use and environmental concerns, the achievable Basin-and-Range potential is about 350 megawatts.

Cascades Resources

The Cascades geologic province extends from Northern California to southern British Columbia. Magma bodies of volcanic origin located along the eastern margin of the range and underlying the major volcanic peaks are believed to offer potentially developable geothermal resources. Unlike the Basin-and-Range province, electricity generation using a Cascades geothermal resource has not been demonstrated. Medium and high temperatures have been measured at feasible depths at several sites, and at least one flow test has been completed. But without temperature and flow tests of production-scale wells, and demonstrated generation of electric power, it is difficult to argue that the reliability and availability of electricity from Cascades geothermal sources is equivalent to the reliability and availability of power from other resources included in the portfolio. The Council is excluding Cascades geothermal resource from its resource portfolio until the feasibility of generating electric power from Cascades geothermal resources is confirmed.

Geothermal Planning Assumptions

The 350 megawatts of geothermal resources further considered for the portfolio of the plan subsequently were modeled as a single resource block. Characteristics of this block are summarized in Table 8-20. Also shown in Table 8-20 are the planning assumptions for additional commercially-developed Cascades geothermal resource that might be proven through development of the demonstration projects. This "Cascades Commercial" resource block was used in portfolio sensitivity analyses.

The capital and operating costs shown in Table 8-20 for the Basin-and-Range block were arrived at by averaging the characteristics of mid-range case binary and flash plants as shown earlier in Tables 8-16 and 8-17.

Costs used for the "Cascades Commercial" block were based on the mid-range flash plant costs of Tables 8-16 and 8-17.

Table 8-20
Geothermal Planning Assumptions
(1990 Dollars)[a]

	Basin-and-Range	Cascades Commercial
Total Capacity (MW)	390	1,111
Total Average Energy (MWa)	350	1,000
Total Firm Energy (MWa)	350	1,000
Unit (Typical plant) Capacity (MW)	25	50
Seasonality	Negligible	Negligible
Dispatchability	Must-run	Must-run
Siting and Licensing Lead Time (months)	24	24
Probability of S&L Success (%)	75%	75%
Siting and Licensing Shelf Life (years)	5	5
Probability of Hold Success (%)	90%	90%
Construction Lead Time (months)	24	36
Construction Cash Flow (%/year)	50/50	25/50/25
Siting and Licensing Cost ($/kW)	$65	$65
Siting and Licensing Hold Cost ($/kW/year)	$13	$13
Construction Cost ($/kW)[b]	$2,739	$2,490
Fixed O,M&R Cost ($/kW/year)[c]	$95	$86
Variable O&M Cost (mills/kWh)	4.5	3
Earliest Service	1994	1998
Peak Development Rate (units/year)	4	4
Service Life (years)	30	30
Real Escalation Rates (%/year)		
Capital Costs	0%	0%
Fuel Costs	0%	0%
O&M Costs	0%	0%

a The Washington State Energy Office assessment of geothermal was prepared in January 1990 dollars, with the understanding that the price year of the draft plan would be 1990. Because of an oversight discovered only as the final draft plan was being prepared, the geothermal costs used in the analysis of the resource portfolio are in 1990 dollars, although other resource costs are in 1988 dollars. This discrepancy will be corrected in the final plan when all resource costs are adjusted to a 1990 base year. Reference energy costs of Table 8-1 are all in 1988 dollars.

b Includes post-operational capital replacement and decommissioning.

c "Overnight" cost, excludes interest during construction.

Conclusions

The geothermal energy resources of the Pacific Northwest may have the potential to produce several thousand megawatts of electric energy at costs less than or competitive with electric energy from new coal-fired power plants. Although geothermal resources have not been commercially developed in the Pacific

Northwest, certain geothermal resource areas within the Basin-and-Range geological province of eastern Oregon and southern Idaho appear to be sufficiently well-understood to consider 350 megawatts of energy from Basin-and-Range resources available for development if needed, during the 20-year planning period.

But the majority of Pacific Northwest geothermal resources, comprising perhaps several thousand megawatts of electric energy potential, are thought to underlie the Cascades Range. These resources are not yet well enough understood to consider them available for the resource portfolio. This plan recommends that an effort be undertaken to confirm the feasibility of generating electricity from these resources.

With proper management of geothermal fields, geothermal resources are likely to be sustainable. Regulatory provisions for "unitized" management of geothermal resources are in place throughout the region with the exception of Washington. This plan recommends that final regulations providing for unitized management of geothermal resources be adopted in Washington.

Contemporary geothermal power plants are highly reliable and can produce baseload power at availabilities exceeding 90 percent. Electric energy from commercial-scale plants at better Northwest sites are estimated to cost about 7.5 to 8.0 cents per kilowatt-hour, well within the competitive range for new generating resources. Development can be undertaken in increments of 30 to 50 megawatts allowing supply to be well-coordinated with need. Lead times (24 months for financing, siting and licensing, 24 to 36 months for construction) are among the shortest for generating resources.

It is likely that airborne effluents, solid waste production and water-borne pollutants potentially resulting from geothermal generation can be controlled to acceptable levels. However, emission control technologies and other environmental mitigation measures need to be demonstrated for geothermal power production using regional resources. This can be achieved by the development of demonstration geothermal projects.

An additional and possibly more significant constraint in both the Cascade and Basin-and-Range provinces is the proximity of promising geothermal resource areas to pristine and sensitive lands of local, state and national significance. With certainty, there will be geothermal resources that must remain undeveloped because of this potential for conflict. To direct geothermal development to areas of lesser sensitivity and to reduce the lead time required to license geothermal projects, this plan recommends that baseline environmental data collection be undertaken at promising geothermal resource areas and that a process begin to identify and to resolve potential constraints to the development of the region's most promising geothermal resource areas.

The Council's recommendations for geothermal resource actions are further discussed in Volume II, Chapters 1 and 16.

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Municipal Solid Waste[16]

Around the world, electricity has been generated using municipal solid waste for fuel for many years. There are several well-established technologies and experienced vendors. Adoption of this technology has been more widespread in Europe than in the United States. This is at least partly due to the relative scarcity of disposal sites in Europe. This scarcity makes the reduction of waste volume that results from generation more valuable and adoption of the practice more likely.

The Pacific Northwest has three operating municipal solid waste facilities that generate electricity. The largest is in Brooks, Oregon. Design capacity of this facility is 550 tons per day of municipal solid waste, with a net electric output of 11 megawatts. This facility uses the "Martin grate system" that is in service throughout the world. It has both a dry scrubber and a baghouse for pollution control. Thermal Reduction Company in Bellingham, Washington, has a 1-megawatt capacity plant that burns 100 tons per day of solid waste in a "Consumat" shop-built incinerator. This facility has an electrostatic precipitator for pollution control and will be adding a scrubber for acid gas control. Skagit County, Washington, has a 2-megawatt capacity plant that burns 180 tons per day. This facility uses a rotating kiln furnace and has a dry scrubber and a baghouse for pollution control. The city of Spokane, Washington, plans to build an 800-ton per day facility that generates 16 megawatts of power. The construction of this facility has been delayed by permit requirements. Tacoma Light Division is repowering an existing steam electric plant to operate on a mix of wood refuse, coal and refuse-derived fuel. The 38-megawatt capacity plant is expected to produce about 35 megawatts of energy. This plant will use a circulating fluidized-bed furnace with limestone injection for sulfur dioxide control and a baghouse for particulate control.

Municipal solid waste was considered a promising technology in the Council's 1986 plan, but was not included in the resource portfolio because of uncertainties regarding air quality, traffic and other issues leading to difficulty in siting municipal solid waste generation projects.

16./ Much of the background information and analysis in this section was taken from an issue paper prepared for the Council by Dr. J.D. Kerstetter of the Washington State Energy Office. This paper (Kerstetter, 1989) appeared in Council staff issue paper 89-41, *Biomass Resources*, October 16, 1989. The Northwest Power Planning Council appreciates the assistance that it has received from the Washington State Energy Office in assessing the municipal solid waste generating potential in the Pacific Northwest.

Technology

Technologies for recovering energy from municipal solid waste can be separated into two principal categories: technologies that burn unseparated and untreated waste ("mass-burn" technologies); and technologies that burn fuel extracted from municipal solid waste ("refuse-derived fuel"). Power plants that burn landfill gas generated by landfill disposal of waste might also be considered in this category.

Mass Burn

Mass-burn plants use direct firing of unprocessed municipal solid waste in steam-electric power plants. Mass-burn facilities have been in use worldwide since the beginning of this century. Mass-burn facilities include modular units, which are shipped to the site more or less completely assembled, and site-built units, which are generally larger in capacity. Mass-burn technology has the advantage of technological maturity, compared to refuse-derived fuel technology, and it tends to be somewhat less expensive to build for comparably-sized plants. A disadvantage of mass burning is that the fuel varies widely in its heat content and other characteristics. This fuel variability complicates the operation of mass-burn facilities.

Refuse-Derived Fuel

Refuse-derived fuel technologies involve the separation of the combustible component from municipal solid waste and the processing of the combustible component into a form that is uniform and easily handled. The resulting fuel can take a variety of forms. "Fluff," which is essentially small pieces of paper and plastic, is the most commonly used, but the fuel also can be pressed into pellet or briquet form, ground into dust or processed into a sludge. This fuel is then used to fire a conventional steam-electric power plant.

The equipment necessary for separating and processing refuse-derived fuel raises the capital cost, relative to mass-burn technologies. However, the extra cost of this equipment can be offset partially by income from recovered recyclable materials (e.g., glass, metal) and by the smaller furnace size and higher combustion efficiency made possible by greater uniformity and higher heat content of the processed fuel. An additional advantage of refuse-derived fuel technology is reduced corrosion, due to prior separation of abrasive and non-combustible materials and better control of the combustion process. Disadvantages follow mainly from the technology's relative immaturity. Problems with various stages of waste processing and burning have been more common with refuse-derived fuel facilities than with mass-burn facilities.

Landfill Gas

Landfill gas, a mixture of carbon dioxide and methane, is produced by anaerobic microorganisms in sanitary landfills. The gas is collected by a system of pipes built into the landfill. (The collection of landfill gas is required, whether or not the gas is to be used as fuel, because of the combustible nature of the substance.) The gas can be processed into medium-Btu or high-Btu gas and either sold into the natural gas pipeline system or burned to generate electricity.

The collection and use of landfill gas is a well-established technology. Its performance and cost-effectiveness are site-specific, but are generally favorable. There are more than 30 landfill gas recovery facilities in the state of California alone. In contrast to the mass-burn and refuse-derived fuel technologies, the collection of landfill gas does not reduce the volume of material that must be disposed of in landfills.

Development Issues

A very significant issue affecting development of municipal solid waste energy projects is the problem of siting facilities. Proposed projects often face considerable opposition from people living nearby. Opponents of projects express concern about traffic and dirt resulting from delivery of the waste to the facility and air pollution resulting from burning the waste. Emission control technology is available to meet current air-quality standards, but there is concern about the adequacy of these standards. Council studies suggest that at forecast costs of municipal solid waste disposal, electricity can be generated from municipal solid waste at costs less than the cost of electricity from many alternative resources. But, current public perception and economics probably will make any new energy-recovery facilities difficult to build in the next decade.

Effects of Recycling

A second development issue arises from the interaction between the economics of energy generation using municipal solid waste and the fraction of municipal solid waste that is recycled. Recycling reduces the total volume of waste that can be used as fuel for generation and may reduce the heat value of the fuel. Many people think recycling should and will become more widespread, which would affect the economics of energy generation using municipal solid waste. Given this situation, the future economics of generation are uncertain.

Air-Quality Concerns

State-of-the-art municipal solid waste energy recovery facilities are able to meet all air-quality standards throughout the region. Table 8-21 shows the emissions from a unit similar to the Marion County facility.

The public is still concerned about the adequacy of existing air-quality standards, in part, because allowable levels have not been established for all pollutants from municipal solid waste plants. This concern can cause lengthy delays in siting and obtaining permits for new facilities. Recently, the proposed Spokane incinerator was required to add nitrogen oxides control measures in order to obtain an authority-to-construct permit. The final permit was issued in September 1989, about seven years after the feasibility study was completed.

Table 8-21
Measured Emissions from Stanislaus County Resource Recovery Facility

Parameter	Units	Concentration	Permit Level
Nitrogen Oxides	ppm[a]	103	200
Sulfur Oxides	ppm	4.1	30
Carbon Dioxide	ppm	43	400
Total Hydrocarbons (as CH_4)	ppm	4	70
Particulate	gr/dscf	0.011	0.0275
Hydrochloric Acid	ppm	1.28	50
Fluoride	ppm	0.16	3
Ammonia	ppm	4.4	50
Arsenic	ug/Nm3	0.77	N/A
Beryllium	ug/Nm3	<0.0005	N/A
Cadmium	ug/Nm3	2.10	N/A
Chromium	ug/Nm3	12.0	N/A
Nickel	ug/Nm3	22.2	N/A

[a] Parts per million.

Reference: Hahn, J.L., *International Conference on Municipal Waste Combustion*, Vol. 1, Hollywood, Florida, 1989.

Global Warming

The net effect of electricity generation using municipal solid waste on atmospheric concentrations of greenhouse gases is unclear. Of the combustible fraction of municipal solid waste, probably 80 to 90 percent is biomass, mostly paper products. Burning this biomass produces carbon dioxide, the major greenhouse gas. If this biomass is replaced by replanting trees or other plants, however, an equal amount of carbon dioxide will eventually be absorbed from the atmosphere by the new plant growth. Thus, in the long run, biomass combustion makes a zero net contribution to atmospheric carbon dioxide concentrations, if the biomass fuels are regrown.

Over the next several decades, there will be an increase in atmospheric carbon dioxide until the biomass is totally replanted and starts to mature. In addition, while fossil-based municipal solid waste (e.g., plastics) that is burned as fuel is usually a small percentage of total fuel, its combustion will increase atmospheric carbon dioxide in the same way as other fossil fuels.

In sum, generating electricity using municipal solid waste probably results in lower levels of carbon dioxide in the atmosphere than generating using a fossil fuel such as coal. Compared to other generating technologies such as wind, geothermal or nuclear, however, the use of municipal solid waste as fuel for electricity generation may result in higher levels of carbon dioxide. However, with landfill disposal of municipal solid waste, the biomass decays to methane that, if released, is many times worse than carbon dioxide as a greenhouse gas.

Municipal Solid Waste Generating Potential in the Pacific Northwest

The future availability of municipal solid waste for electricity generation in the Northwest was estimated by the Washington State Energy Office in a paper entitled "Assessment of Biomass Resources for Electric Generation in the Pacific Northwest" (Kerstetter, 1989). The Washington State Energy Office estimated that a maximum of 13 trillion Btu of municipal solid waste per year is available for use in new municipal solid waste plants. The average tipping fee[17] paid to the operator of the municipal solid waste facility by the municipal solid waste hauler was estimated to be $6.50 per million Btu.

The quantity of municipal solid waste generated in an area depends on the area's population and economic activity. In most cases, it is predicted that recycling programs will keep the level of solid waste requiring disposal from growing significantly over the next 20 years. Paper and wood recycling reduces the amount and energy content of material available for electricity production.

For economic reasons, it is unlikely that an energy-recovery facility with electric power production will be built with a disposal capacity of less than 100 tons per day. Estimated volumes of solid waste that would be available for energy recovery in 1990 are shown in Table 8-22. This table excludes waste required for operating facilities in Marion County, Oregon; Skagit County, Washington; Bellingham, Washington; and planned facilities in Spokane and Tacoma.

The potential impacts of generating plants using municipal solid waste, including air pollution, truck traffic, noise and odor, have contributed to public opposition in communities near proposed sites. While the economics of these plants often are sufficiently attractive to allow mitigation or compensation for negative impacts on nearby communities, the Council's judgment is that use of the entire municipal solid waste resource for electricity generation is unlikely during the planning period. Figure 8-15 shows the estimated probabilities of various levels of use of municipal solid waste for electricity generation. The Council decided to use 4 trillion Btu for planning purposes, roughly 30 percent of the maximum potential of 13 trillion Btu. This level has the highest probability of occurring; there also are roughly equal probabilities attached to exceeding or falling short of this level. Four trillion Btu of fuel will support 30 average megawatts of electricity production. As indicated, the plant operator can expect to receive $6.50 per million Btu (approximately $30 per ton) of fuel taken.

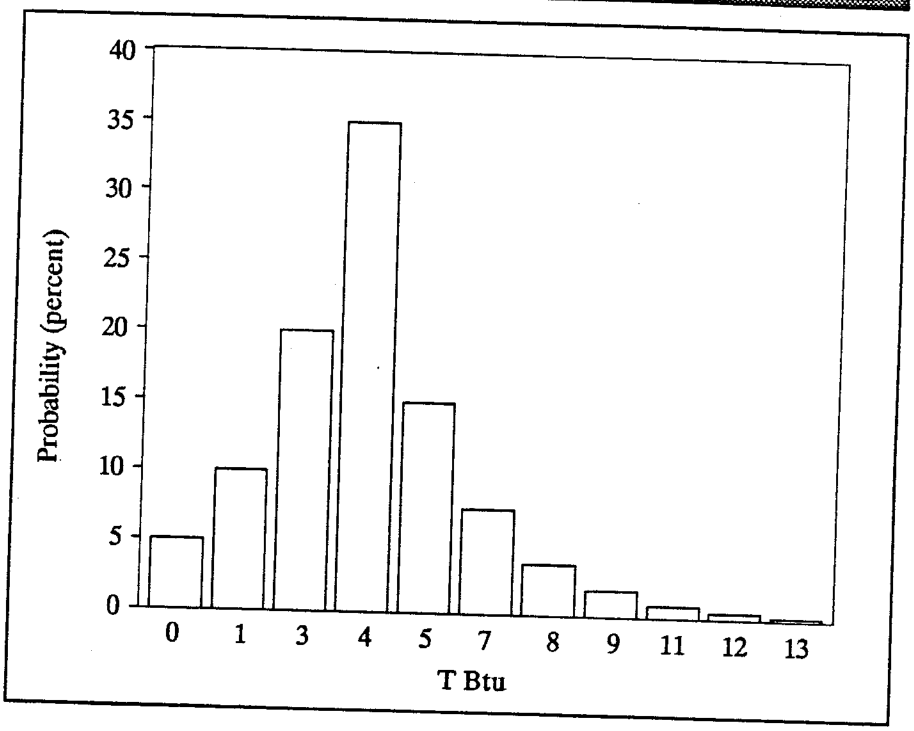
17./ A tipping fee is the cost to municipal solid waste haulers to dump their garbage at the municipal solid waste facility. This fee is determined, in part, by the costs to dump waste at landfills and other alternatives. Because haulers pay to dump the municipal solid waste, the cost of fuel to an operator of an municipal solid waste facility is negative.

Table 8-22
Municipal Solid Waste Potentially Available for Energy Recovery

State	MSW (tons/day)	MSW Energy (trillion Btu/yr.)	Potential Electric Energy (MWa)
Idaho	750	1.1	8
Montana	330	0.5	4
Oregon	3,360	5.1	40
Washington	5,450	8.3	60
Regional Total	9,890	15	112

MSW Availability

Figure 8-15
Probable Availability of Municipal Solid Waste



Representative Municipal Solid Waste Power Plant

A 10-megawatt capacity mass-burn steam-electric plant was selected as representative of the type of plant that might be developed to produce electricity consistent with meeting future refuse disposal needs in this region. Mass-burn technology is one of the leading technologies currently being used for refuse-to-energy plants. The 10-megawatt size is likely to be somewhat smaller than a typical plant built to meet the needs of a large metropolitan area, but it is larger than plants built to serve more sparsely populated areas. The heat rate of municipal solid waste plants, and the costs of construction and operation appear to be more sensitive to plant size than to technology. The performance and costs associated with a 10-megawatt unit should be generally representative.

The cost and performance characteristics of the representative plant are shown in Table 8-23. The costs were taken from an earlier Council study (Battelle, 1982a) and escalated to 1988 dollars. Plant heat rate and availability factors were taken from the same study. Because of the vintage of these performance and cost figures, they should be used with caution. In particular, contemporary and future plants may incorporate more extensive environmental control technologies than the plants upon which these costs are based. This would likely result in increased construction and operating costs. The Council intends to review its municipal solid waste plant cost and performance information in conjunction with the assessment of biomass research, development and demonstration needs called for in the Action Plan.

The siting and licensing and construction lead times of Table 8-23 are taken from a Council study of methods to shorten power plant development lead times (Battelle, 1982b). These estimates, too, are expected to be reviewed during the assessment of biomass research, development and demonstration needs.

Table 8-23
Cost and Performance Characteristics of
a Representative Municipal Solid Waste Power Plant
(1988 Dollars)

10 Megawatt Mass-burn Steam Electric Plant	
Rated Capacity (MW)	10
Peak Capacity (MW)	10
Equivalent Availability (%)	87%
Annual Energy (MWa)	8.7
Heat Rate (Btu/kWh)	20,000
Siting and Licensing Cost ($/kW)	$140
Option Hold Cost ($/kW/year)	$11
Construction Cost ($/kW)[a]	$3,450
Fixed O&M Cost ($/kW/year)	$188
Variable O&M Cost (mills/kWh)	14.3
Post-op Capital Replacement Cost ($/kW/year)	$69
Siting and Licensing Lead Time (months)	24
Construction Lead Time (months)	36
Service Life (years)	30

a "Overnight" costs (excludes interest during construction).

Table 8-24
Reference Energy Costs for a
Representative Municipal Solid Waste Power Plant
(cents per kilowatt-hour)

	Real ($1988)	Nominal (30 year)	Nominal (40 year)
10-Megawatt Municipal Solid Waste Plant	-3.6	-6.1	-6.8

Reference Energy Cost Estimates

Reference energy costs for the representative municipal solid waste power plant are shown in Table 8-24. These costs were calculated using the reference financial and service date assumptions discussed in the introduction to this chapter. The plant is assumed not to be dispatchable, hence the capacity factor is equal to the plant availability factor.

Unlike other resources in this plan, the municipal solid waste plant has a negative energy cost. This is because the fuel price is negative (-$6.60 per million Btu). That is, municipal solid waste haulers pay the plant operator for the right to dump the solid waste. Although the costs in Table 8-24 are the Council's best estimate of the cost of electricity from this resource, utilities most likely will pay a negotiated price for the electricity produced.

Attempts to site and license municipal solid waste-fueled generating plants have been more difficult than one would expect for a technology that delivers electricity at negative cost. One reasonable interpretation of this situation is that opposition is due to environmental costs, either real or perceived, that are not represented in Table 8-24. Dealing with this opposition is likely to raise the cost of the generating plant because of increased mitigation, compensation for environmental externalities and increased time and effort required to get the plant sited and licensed.

Another possibility is that a substantial increase in recycling could reduce pressure on landfills, which would tend to reduce the amount of municipal solid waste and to lower tipping fees. These effects would increase the cost of electricity generated by municipal solid waste. Increased recycling also is likely to remove some of the highest-quality fuel (paper) from the waste stream, which would tend to increase the cost of electricity from municipal solid waste.

Thus, it is likely that the cost to the region for electricity from municipal solid waste plants will be higher than the reference costs in Table 8-24.

Planning Assumptions

Because the actual cost of energy is uncertain, and the price utilities pay for this resource will be negotiated, the Council has assumed that the price charged to utilities will be just under the regional avoided cost of 8 cents per kilowatt-hour at the time these plants are expected to come online.

The use of the price charged to the utility system rather than regional cost is different than the treatment for most resources. But, the modest size of the municipal solid waste resource means that the rest of the portfolio and the conclusions of the portfolio analysis are not significantly distorted. Until the obstacles to siting and licensing municipal solid waste-fueled power plants are better understood, the current treatment of costs appears to be the most reasonable available.

Assumptions used in the resource portfolio analysis of municipal solid waste-fired power plants are shown in Table 8-25.

Conclusions

The Council considers 30 average megawatts of generating resources fired by municipal solid waste to be available to the region for planning purposes. The cost of electricity generated by these resources can vary widely, depending in part on the level of tipping fees charged to accept the waste. Table 8-24 demonstrates that at the level of tipping fee assumed by the Council, the resulting cost of electricity from municipal solid waste ("Reference Energy Cost") is negative. This very attractive cost of electricity, at least in principal, could make it possible to mitigate environmental impacts on communities near generating facilities, or to compensate the communities for impacts that are not mitigated.

However, until mitigation or compensation mechanisms are developed, opposition from communities near proposed generation sites can be expected to continue complicating development of the resource. The other principal development issue confronting waste-to-energy facilities is uncertainty regarding future levels of recycling.

The Council's Action Plan directs the Research, Development and Demonstration Advisory Committee to examine obstacles to the development of generating facilities using biomass, including municipal solid waste.

Table 8-25
Municipal Solid Waste Planning Characteristics

Total Capacity (MW)	38
Total Average Energy (MWa)	30
Total Firm Energy (MWa)	30
Unit (typical project capacity per MW)	9.4
Seasonality	None[a]
Dispatchability	Must-run
Siting and Licensing Lead Time (months)	24
Probability of S&L Success (%)	33
Siting and Licensing Shelf Life (years)	5
Probability of Hold Success (%)	75
Construction Lead Time (months)	36
Construction Cash Flow (%/year)	b
Siting and Licensing Cost ($/kW)	b
Siting and Lic. Hold Cost ($/kW/year)	b
Construction Cost ($/kW)	b
Fixed O,M&R Cost ($/kW/year)	b
Variable O&M Cost (mills/kWh)	b
Earliest Service	2000
Peak Development Rate (units/year)	One unit every 3 years
Service Life (years)	30
Real Escalation Rates (%/year)	
Capital Costs	0%
Fuel Costs	0%
O&M Costs	0%
Power Purchase Price (cents/kWh)	b
Levelized Real	4.1[c]
Levelized Nominal	8.0[c]

a The quantity of solid waste tends to peak in the summer, but the seasonal shape of output from municipal solid waste-fired generating plants is influenced by such factors as composting of yard debris, use of supplemental fuels and the scale of the generating plant relative to its service area. As a result, the output is assumed to be constant throughout the year.

b Power-purchase price is used for the resource portfolio analysis of municipal solid waste plants. For this reason, individual cost components are not used.

c These prices are assumed to be negotiated between municipal solid waste plant operators and utilities and are set here at the regional avoided cost for power.

References

Battelle, Pacific Northwest Laboratories. 1982a. *Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest: Volume V - Biomass.* Prepared for the Northwest Power Planning Council, Portland, Oregon.

Battelle, Pacific Northwest Laboratories. 1982b. *Development and Characterization of Electric Power Conservation and Supply Resource Planning Options.* Prepared for the Northwest Power Planning Council, Portland, Oregon.

Hahn, J.L. and Sofaer, D.S. *Air Emission Test Results From the Stanislaus County, California Resource Recovery Facility*, International Conference on Municipal Waste Combustion, Volume 1, Conference Proceedings, U.S. Environmental Protection Agency, Hollywood, Florida, 1989.

Kerstetter, J.D., "*Assessment of Biomass Resources for Electric Generation in the Pacific Northwest.*" Prepared for the Northwest Power Planning Council by the Washington State Energy Office, Olympia, Washington, 1989.

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New Hydroelectric Power

The streams and rivers of the Pacific Northwest have provided abundant opportunities for generation of electric power by harnessing the energy of falling water. About 29,800 megawatts of hydropower capacity has been developed in the Pacific Northwest, principally on the Columbia River system. This represents about 74 percent of the region's electrical generating capacity. This capacity, on average, provides about 16,400 megawatts of energy, 12,300 megawatts of which is considered firm energy (see Volume II, Chapter 4). On average, the region relies on hydropower for about two-thirds of its electricity.

The theoretical potential from new hydropower projects in the Pacific Northwest has been estimated to be about 39,000 megawatts of capacity and 25,000 megawatts of energy (Synergic Resources Corporation, 1981). But there are significant environmental, economic and institutional constraints to the development of most of this additional potential. As described below, the Council estimates that about 1,060 megawatts of new hydropower capacity can likely be developed at costs less than 11.8 cents per kilowatt-hour. This capacity could produce about 510 megawatts of energy on average, 410 megawatts of which would be firm. Most of this power would come from small-scale projects and incremental additions to existing large and small projects. Hydropower generating projects that likely can be developed include irrigation, flood control and other non-power water projects that could be retrofitted with generation equipment; addition of generating equipment to existing hydropower projects; plus some undeveloped sites that may be suitable for development.

Hydropower Technology

Hydropower plants extract energy from falling water. This requires vertical drop ("operating head") and water flow. Water from a higher level is delivered to a turbine, where the energy of the flowing water is converted into mechanical energy as the turbine rotates. Electricity is then generated in the ordinary way by connecting the turbine to an electrical generator. Types of hydropower projects include instream projects, diversions, and canal or conduit projects. For instream projects, operating head is created by a dam, which backs water up the stream channel. Sometimes the dam may impound sufficient water to permit daily or seasonal regulation of streamflow so power can be generated as needed, regardless of the amount of water flowing down the river. These are called storage projects. Projects without such reservoir storage ("run-of-river" projects) generate power as streamflows permit.

In a diversion project, water is diverted from the stream by a diversion structure (generally a low dam or weir) and conveyed to a downstream powerhouse by a canal or conduit. The distance between the diversion structure and the powerhouse may be very short, as in a diversion around a natural waterfall, or may be many miles. The operating head is determined by the difference in elevation between the diversion structure and the powerhouse. Sometimes the diversion structure is a high dam that may provide additional operating head or water storage.

A canal or conduit hydropower project uses operating head created by water conveyance structures installed primarily for non-power purposes, such as irrigation canals and municipal water supply conduits.

Hydropower Development Issues

Hydropower is a renewable energy resource, and its development and operation are relatively free from toxic emissions and solid waste problems. Although the capital costs of hydropower projects are often high, these costs make up the majority of hydro energy costs and so, once invested, reduce uncertainties regarding the future costs of energy from a given site. Because hydropower equipment operates under relatively benign environmental conditions, the anticipated lifetime of hydropower developments is generally longer than for other energy generating facilities.

As with any generating resource, there are potential problems associated with hydropower. As mentioned above, capital costs are often quite high. Siting, licensing and design are typically complex and frequently require a long lead time. Hydropower sites often are remote from load centers and may require long transmission lines. Transmission and road access costs easily can render small remote projects economically infeasible. Because streamflows are affected by annual weather conditions, a portion of the average output of most hydropower projects is nonfirm energy, that is, energy that cannot be counted on with certainty to meet customers' demand. But unlike such renewables as wind or solar power, hydropower is rarely intermittent on a daily basis. Some projects may generate most of their energy in the spring--a time when the value of their energy is low due to generally large flows in the Columbia River system. Conversely, winter-peaking projects may have extra value because of the increased demand for power at that time.

Environmental Issues

During the construction phase and throughout the operating life of hydroelectric projects, varying levels of environmental effects can be expected, based primarily on location of the project, type of project (i.e., new dam or reservoir versus addition to existing structure) and mode of operation. Of these three determinants of environmental impacts, the location of the project is most significant. The principal environmental concerns regarding hydroelectric development in the Pacific Northwest are:

- water quality impacts (chemical, biological and thermal);
- hydrology impacts (surface water and groundwater);
- erosion and sedimentation impacts;
- land use impacts;

- dust (during construction);
- noise (during construction); and
- fish and wildlife impacts (at the project site, upstream and downstream, and along the transmission corridor).

Although the environmental issues that may be raised for any one project are heavily dependent on the site characteristics of the project, it generally can be assumed that projects that involve an existing dam will experience incrementally less environmental impact than projects requiring new dam construction. The same is true for run-of-river projects versus storage projects.

Water Quality Impacts

Water quality impacts resulting from the construction and operation of hydroelectric projects may be chemical, biological and/or thermal in nature. These impacts may be experienced downstream of the project or in the backwater caused by the project. Water quality changes, although not always adverse, are of concern because of effects on the aquatic environment and on the beneficial uses of water.

For hydroelectric development, the primary water quality concerns are thermal changes, nitrogen supersaturation, turbidity and oxygen depletion.

Thermal Changes

Changes in the thermal characteristics of streamflow are most likely to occur as a result of the operation of large storage projects with deep, poorly mixed reservoirs. Thermal changes can have a pronounced impact on the resident fishery as well as on the anadromous fishery. Many species are intolerant to very wide fluctuations in stream temperature. Multiport intake structures, which mix the water from several different reservoir layers, can be included in the design of storage projects. In this manner, stream temperature can be better held within required tolerances for the successful maintenance of fisheries.

Nitrogen Supersaturation

Nitrogen supersaturation is a serious water quality problem below many of the dams on the Columbia and lower Snake rivers. Air entrained in spill over the dams is carried to depths in the plunge pools below the dams, where sufficient hydrostatic pressure exists to cause the nitrogen to dissolve above normal saturation levels. The increased nitrogen concentrations can cause lethal respiratory effects in fish.

Turbidity

Large quantities of suspended material can enter waterways as a result of disturbance of the natural terrain during construction. Not only are the visual effects of high turbidity displeasing, but significant turbidity also may impair development of nutrient-assimilating plant life on the bottom of streams and reservoirs.

Oxygen Depletion

Although most dissolved oxygen problems are caused by improperly or inadequately treated sewage discharged into the water course, impoundments also can have a significant impact on dissolved oxygen concentrations. Salmonid fish require dissolved oxygen concentrations in excess of five milligrams per liter for migration and higher levels for spawning and rearing. Intense algal blooms can cause extreme diurnal fluctuations in dissolved oxygen concentrations in impoundments, thus causing stress on the fishery.

Hydrology Impacts

Changes in the hydrologic regime resulting from hydroelectric development include the possibility of converting a portion of a free-flowing stream into backwater, diverting water from its natural course and altering the natural groundwater recharge pattern. The changes in hydrology are environmental impacts in themselves, but they also create additional environmental impacts that may be of greater significance. For example, a reservoir is not necessarily cause for environmental concern. However, the presence of the reservoir may cause deleterious impacts on fish and wildlife and water quality. Changes in hydrology are the causal agents for many interrelated environmental effects.

Erosion and Sedimentation

Erosion and sedimentation problems may occur during construction of hydroelectric projects and continue long after the project is retired. Naturally free-flowing water has a certain sediment-carrying capacity, which normally is in near-term dynamic equilibrium with hydrologic and geologic processes. A change in the hydrology (i.e., temporal distribution of stream flows) and/or a change in the sediment load will upset this equilibrium, resulting in increased channel scour or sediment deposition.

Hydroelectric developments, depending on design and scale, tend to impact erosion and sedimentation patterns in different ways. In general, sediment loads will settle in a reservoir because of the reduction in flow velocities in the reservoir. As a result, increased sedimentation occurs in the backwater formed by the reservoir. Mudflats and bars may develop while reservoir storage capacity is lost. Consequently, the water released from the reservoir has a reduced sediment load. In many cases, the release water has a propensity for a greater sediment load and channel scour occurs downstream of the dam. Channel scour may have a significant impact on aquatic biota and channel stability.

Land Use

The amount of land required for a hydroelectric project is highly dependent on the type and size of the development. For large storage projects, a tremendous amount of acreage may be required. For instance, the area of the reservoir established by Grand Coulee Dam exceeds 80,000 acres (125 square miles) at normal reservoir elevation. In contrast, the amount of land required for the installation of a new micro-scale, run-of-river plant may be less than an acre. The amount of acreage required for additions to existing structures is generally small, including areas for the storage of equipment and construction materials during construction.

Dust

Construction activities, particularly earth moving in the more arid regions of the Northwest, may cause significant blowing of dust in and around the immediate project area. Dust-related problems are primarily limited to the period during which construction takes place and can usually be controlled by watering exposed or disturbed areas.

Noise

Like dust problems, noise pollution will occur during construction, due to the operation of heavy construction equipment. During operation, hydroelectric plants are relatively quiet.

Fish and Wildlife Impacts

Most hydroelectric dams in the Pacific Northwest represent migration barriers to the passage of upstream (adult) and downstream (juvenile) anadromous fish. Juvenile downstream migrants are lost at each dam by passage through the turbines, by exposure to water supersaturated with air, by delay in time of migration and by increased predation. Adult migrants face migration delays, loss of energy reserves, physical injury and disease exposure at each dam when traversing fishways.

The filling of an impoundment behind a hydroelectric dam inundates large areas of land and transforms a free-flowing river into a lakelike environment. The result is a transition of habitat, a change in composition of terrestrial and aquatic biota at the site and a change in usage by man. Changes resulting from habitat transition may be beneficial or detrimental for some forms of wildlife. In the Pacific Northwest, spawning and rearing areas used by salmonid fishes (salmon, seagoing trout) in free-flowing rivers can be destroyed by water impoundment, resulting in reduction or loss of a valued resource. Such losses may require operation of salmonid hatcheries and other mitigation measures.

Operation of hydroelectric facilities to meet peak energy demands causes fluctuations of water level in both the impoundment and the stream below. Fluctuating water levels may preclude development of shoreline vegetation, reduce shoreline use by riparian species of wildlife, and lower reproductive success of fish species that spawn near the impoundment margin. Fluctuations in rivers below dams strand immature fish on shorelines or in shallows and may expose eggs of shoreline spawners and intergravel redds (nests) of salmonids. Water level changes cause losses of invertebrate populations that inhabit shoreline areas.

Dams also tend to advance the time when water temperatures are warmest (Jaske and Goebel, 1967), so that this occurs near the time of mainstream salmon spawning. Hundreds of miles of river have been lost as anadromous fish habitat after construction of high dams, e.g., Grand Coulee, Hells Canyon, Oxbow and Brownlee. Storage dams on the Columbia River system have tended to reduce the seasonal fluctuations in river flow, e.g., higher minimum and lower maximum flows. This will make the riparian zone more stable. On the other hand, power-peaking low-head dams produce a daily variable flow that tends to reduce both the size and stability of the shoreline habitat. Impounded waters have inundated islands that were important breeding areas for certain species of birds, for example, Canada geese, and gulls.

Of particular concern to the Council is the potential impact of hydropower development on fish and wildlife. The Council is responsible for protection, mitigation and enhancement of the fish and wildlife resources of the Columbia River Basin. Furthermore, the Council is charged with considering protection, mitigation and enhancement of fish and wildlife, and related spawning grounds and habitat, when assessing the cost-effectiveness of new resources.

To provide guidance for future hydropower development in the region, the Council has designated certain reaches of Northwest streams as protected areas. The Council believes that new hydropower development in such areas would pose unacceptable risk of loss to fish and wildlife species of concern (existing power or non-power water control structures generally are exempted from protected area requirements). The protected areas designations are intended to: 1) protect fish and wildlife resources; 2) send a clear signal to developers regarding the acceptability or non-acceptability of stream reaches for hydropower development; 3) provide planning guidelines for determining the availability of new hydroelectric power; and 4) create a comprehensive plan to provide guidance for licensing decisions by the Federal Energy Regulatory Commission.

Protected areas designations are based on fish and wildlife considerations only and do not reflect other river values that might affect the desirability of hydropower development.

The Council intends that future hydropower development be undertaken in an environmentally responsible manner. To achieve this objective, future hydropower development is expected to comply with the Council's protected areas policies. In addition, all hydropower development, regardless of location, should include actions to mitigate environmental impacts to the extent practicable. Unavoidable impacts should be considered when assessing project cost-effectiveness. The Council expects that future hydropower development will comply with the conditions for hydropower development set forth in Volume II, Chapter 11.

New Hydropower Potential in the Pacific Northwest

This draft plan relies on the estimate of new hydropower potential that was developed for the 1989 Supplement to the 1986 Power Plan and takes into account protected areas designations. In the 1989 supplement, the Council concluded that about 410 megawatts of firm energy is potentially available from new hydropower development at costs of 11.8 cents per kilowatt-hour or less. This estimate has not been revised for the 1991 draft plan, because information and events occurring since preparation of the 1989 supplement are judged not to have significantly affected the estimated supply of new hydropower. The process by which the Council arrived at the estimates of new hydropower appearing in the 1989 supplement is described below.

The estimate of new hydropower potential is based upon an inventory of potential projects contained in the Pacific Northwest Hydropower Site Data Base, the river resource assessment of the River Resources Data Base and the guidance to hydropower development provided by the Council's protected areas policy.

Concerns regarding the environmental impact of new hydropower, and particularly, the possibility of conflict with the Council's fish and wildlife program led the Council to seek improved information regarding new hydropower sites and potentially affected streams. Through the joint efforts of the Council, the U.S. Army Corps of Engineers and Bonneville, a Pacific Northwest Hydropower Site Data Base was developed (Corps of Engineers, 1986). This data base contains the location, cost and performance information on all hydropower projects in the Pacific Northwest that have been submitted to the Federal Energy Regulatory Commission for permitting, licensing or exemption. The data base also includes existing hydropower projects and sites identified by the Corps of Engineers' National Hydropower Survey. Associated with the site data base are computer algorithms for estimating project capacity, energy production and cost.

The need to better understand the qualities of streams affected by proposed hydroelectric development led the Council and Bonneville, with the assistance of federal agencies, the states and the Indian tribes, to undertake a comprehensive assessment and evaluation of regional river resource values. This work included surveys of anadromous fish, resident fish, wildlife, natural features, cultural features, recreation and Indian cultural sites for 134,000 stream miles, representing 39 percent of the region's total stream miles. Not included are most streams that are currently protected from hydropower development by federal legislation (for example, streams located within National Wilderness Areas), and small headwater streams. Each stream reach is classified as to the presence or absence of anadromous fish and ranked, using four levels of value, for each of the other environmental considerations noted above.

New hydropower potential was estimated using a multi-step process. First, the technical hydropower potential was estimated using records of projects proposed for permitting. Next, projects pre-empted by federal protection and the Council's protected area designations were eliminated. Developable potential was then estimated, based on project licensing status and the environmental characteristics of the river reach in which the project would be sited. Finally, the economically developable potential was assessed by estimating the cost of energy from the remaining projects.

Technical Potential

The Council's estimated technical potential for new hydropower development is based on an inventory of proposed projects located within the four-state region, west of the Continental Divide. Projects included in the inventory are those that have been active in the Federal Energy Regulatory Commission permitting and licensing process. Physically competing proposals were excluded, as were pumped storage projects, since the latter are not net-energy producers. Proposed federal projects were excluded because of incomplete information on these projects. This omission should not greatly affect the estimated availability of new hydropower, because many of the better federal sites have been filed on by non-federal developers and are therefore included.

Environmental and Institutional Constraints

Projects included in the technical potential category were screened to eliminate those prohibited by environmental and institutional constraints. Two screens were used: current federal stream protection and the Council's protected areas policy. It was assumed that no future development would occur in areas currently having federal protection. These areas include wilderness areas, national parks, and stream reaches included in the National Wild and Scenic Rivers System. Projects not complying with the Council's protected areas rule also were eliminated from further consideration. The protected areas rule permits no new hydropower development within protected stream reaches, except for projects meeting the following criteria:

- Projects located within protected reaches, but licensed or exempted prior to August 10, 1989.

- Power additions to existing power or non-power water control structures located within protected areas.

Developable Potential

About 590 projects passed the institutional screens described above. These are listed in Appendix 8-B. Even projects passing these screens could have environmental problems that may preclude development. Moreover, the technical characteristics of many of these sites have not been fully explored, leading to the possibility that development may not be feasible for engineering or economic reasons. To account for these factors, probabilities of development were estimated for each project passing the institutional screens. These probabilities of development were estimated using the Hydropower Supply Model developed for the Bonneville Power Administration by Ott Water Engineers (Ott, 1987).

Bonneville's Hydropower Supply Model calculates two probabilities of development for a project. One probability is based upon the river resource values of the affected stream reach. (This probability is shown in Appendix 8-B in the column entitled "River.") The second probability is based upon the current permitting or licensing status of the project. (This probability is shown in Appendix 8-B under the heading "Regul.") The lower of the two probabilities was selected as the governing probability of development for the project. (This probability is shown in Appendix 8-B under the heading "Final.") The final probability of development is applied to the energy potential of the project to obtain a probable energy contribution (two columns on the right of Appendix 8-B). The probable contributions of individual projects are summed to obtain the regionwide potential. This method produces a statistical estimate of the expected developable hydropower energy without the need to determine if specific individual projects should be developed--a determination that would be inappropriate given the limited information currently available on specific projects and stream reaches.

This process yielded about 1,230 megawatts of potential new hydropower capacity.

Economic Potential

The final step in estimating new hydropower potential was to calculate the economic feasibility of projects that passed the institutional screens described above. Developer-supplied project capital cost information was used where available. Where developer-supplied information was not available, the cost algorithm of the Hydropower Site Data Base was used to estimate project development costs. Neither developer-supplied nor algorithm-generated costs were available for some projects. The capital costs of these projects were assumed to be distributed in proportion to the capital costs of projects having capital cost estimates. As described earlier, certain projects even though located in protected stream reaches, can be developed, if they meet certain criteria. The estimated cost of developing these projects was increased by 10 percent, because it is expected that the costs for licensing and engineering these projects would be greater than if the projects were not located in protected areas.

Project levelized energy costs were calculated using the reference financial assumptions described in the introduction to this chapter.

The resulting supply curve of new hydropower is shown in Table 8-26. The achievable supply of new hydropower is estimated to be about 1,060 megawatts of capacity. This capacity would supply about 510 megawatts of average energy and about 410 megawatts of firm energy at nominal costs of 11.8 cents per kilowatt-hour or less.[18]

18./ These energy costs were computed on the basis of average energy. The differing values of firm and secondary energy are subsequently accounted for when new hydropower resources are evaluated in the ISAAC Decision Model.

Table 8-26
Cost and Availability of New Hydropower (Achievable)

Nominal[a]	Levelized Cost (cents/kWh)	Average Energy Incremental (MWa)	Average Energy Cumulative (MWa)	Firm Energy Incremental (MWa)	Firm Energy Cumulative (MWa)
0.0 - 2.2	0 - 1.1	9	9	7	7
2.3 - 3.2	1.2 - 1.6	33	42	26	33
3.3 - 4.3	1.6 - 2.2	14	56	11	44
4.4 - 5.3	2.3 - 2.7	58	114	46	90
5.4 - 6.5	2.7 - 3.3	74	188	59	149
6.6 - 7.5	3.4 - 3.8	55	243	44	193
7.6 - 8.7	3.9 - 4.4	86	329	69	262
8.8 - 9.7	4.4 - 4.9	72	401	58	320
9.8 - 10.8	5.0 - 5.5	88	489	70	390
10.9 - 11.8	5.6 - 6.0	23	512	18	408

[a] Hypothetical 1988 in-service.

Upper and lower bounds to new hydropower availability also were estimated. To estimate the possible upper bound of hydropower availability, each site passing the institutional screens was assumed to have a 100-percent probability of development. This assumption yields about 2,300 megawatts of new hydropower capacity, able to produce about 1,100 megawatts of average energy and about 900 megawatts of firm energy at 11.8 cents per kilowatt-hour, or less. This upper-bound supply curve is tabulated in Table 8-27.

Table 8-27
Cost and Availability of New Hydropower (Upper Bound)

Nominal[a]	Levelized Cost (cents/kWh)	Average Energy Incremental (MWa)	Average Energy Cumulative (MWa)	Firm Energy Incremental (MWa)	Firm Energy Cumulative (MWa)
0.0 - 2.2	0 - 1.1	16	16	13	13
2.3 - 3.2	1.2 - 1.6	145	161	116	129
3.3 - 4.3	1.6 - 2.2	35	196	28	157
4.4 - 5.3	2.3 - 2.7	207	403	166	323
5.4 - 6.5	2.7 - 3.3	127	530	102	425
6.6 - 7.5	3.4 - 3.8	106	636	85	510
7.6 - 8.7	3.9 - 4.4	132	768	106	616
8.8 - 9.7	4.4 - 4.9	179	947	143	759
9.8 - 10.8	5.0 - 5.5	119	1,066	95	854
10.9 - 11.8	5.6 - 6.0	70	1,135	56	910

[a] 1988 dollars.

In the lower-bound study, development was limited to sites having existing water control structures (power or non-power). The probabilities of project development estimated for the "likely developable" supply curve (i.e., those shown in Volume II, Chapter 4, Table 4-1) were applied to these sites. This yielded 484 megawatts of new hydropower capacity, capable of producing about 230 megawatts of average energy and about 185 megawatts of firm energy at 11.8 cents per kilowatt-hour, or less. This lower-bound supply curve is tabulated in Table 8-28.

Table 8-28
Cost and Availability of New Hydropower (Lower Bound)

		Average Energy		Firm Energy	
Nominal[a]	Levelized Cost (cents/kWh)	Incremental (MWa)	Cumulative (MWa)	Incremental (MWa)	Cumulative (MWa)
0.0 - 2.2	0 - 1.1	2	2	2	2
2.3 - 3.2	1.2 - 1.6	12	14	10	12
3.3 - 4.3	1.7 - 2.2	4	18	3	15
4.4 - 5.3	2.3 - 2.7	31	49	25	40
5.4 - 6.5	2.8 - 3.3	17	66	14	54
6.6 - 7.5	3.4 - 3.8	24	90	19	73
7.6 - 8.7	3.9 - 4.4	50	140	40	113
8.8 - 9.7	4.5 - 4.9	30	170	24	137
9.8 - 10.8	5.0 - 5.5	47	217	38	175
10.9 - 11.8	5.6 - 6.0	13	230	10	185

[a] 1988 in-service date.

New Hydropower Planning Assumptions

The supply of achievable new hydropower that appears in Table 8-26 is the amount of this resource that the Council will count on for the resource portfolio of the Draft 1991 Power Plan. Because of the range of estimated project costs, this supply was divided into four resource blocks for use in the Council's resource portfolio analysis. The assumptions used to characterize these blocks for planning purposes are shown in Table 8-29.

Table 8-29
New Hydropower Planning Assumptions
(1988 Dollars)

	New Hydro 1	New Hydro 2	New Hydro 3	New Hydro 4
Total Capacity (MWa)	190	290	340	240
Total Average Energy (MWa)	110	130	160	110
Total Firm Energy (MWa)	91	100	130	89
Unit Capacity (Typical Project)(MW)	10	10	10	10
Seasonality	Spring	Spring	Spring	Spring
Dispatchability	must-run	must-run	must-run	must-run
Siting and Licensing Lead Time (months)	36	36	36	36
Probability of S&L Success (%)	50	50	50	50
Siting and Licensing Shelf Life (years)	4	4	4	4
Probability of Hold Success (%)	75	75	75	75
Construction Lead Time (months)	36	36	36	36
Construction Cash Flow (%/year)	25/50/25	25/50/25	25/50/25	25/50/25
Siting and Licensing Cost ($/kW)	$74	$93	$130	$160
Siting and Licensing Hold Cost ($/kW/year)	$3	$4	$4	$5
Construction Cost ($/kW)[a]	$985	$1,240	$1,700	$2,060
Fixed Operating Cost ($/kW/year)	$21	$27	$37	$44
Variable Operating Cost (mills/kWh)	0.0	0.0	0.0	0.0
Earliest Service	1993	1993	1993	1993
Peak Development Rate (Units/year)	6	6	8	8
Service Life (years)	50	50	50	50
Real Escalation Rates (%/years)				
Capital Costs	0	0	0	0
O&M Costs	0	0	0	0

a "Overnight" construction cost (excludes interest during construction).

Through the work of resource agencies, project developers and others, additional information concerning hydropower sites and stream values becomes available on a regular basis. Bonneville, the Corps of Engineers and the Council continually update the river values data base and the Hydropower Site Data Base, so that this improved information becomes available for hydropower resource assessment. For this reason, the Council expects to periodically reassess its estimate of developable hydropower.

Conclusions

The Council considers new hydroelectric resources totaling 410 average megawatts of firm energy to be available to the region for planning purposes. These resources range in cost from less than 2.2 cents per kilowatt-hour to 11.8 cents per kilowatt-hour. Uncertainties about the availability of new hydropower for development also were assessed. This assessment indicated that the availability of achievable new hydropower might range from as little as 185 megawatts of firm energy to as much as 900 megawatts of firm energy.

The principal development issues affecting the development of new hydropower concern effects of new hydroelectric facilities on the environment, principally fish and wildlife. The 410 average megawatt amount used by the Council in its planning is the Council's estimate of the amount that could be developed at acceptable environmental cost.

In the Action Plan, the Council recommends acquiring environmentally acceptable new hydroelectric resources as they become cost-effective.

References

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Nonfirm Strategies

The Northwest hydropower system produces, on average, about 4,100 megawatts of nonfirm energy a year, mostly between January and July. That nonfirm energy serves the top, or interruptible, quartile of the Bonneville Power Administration's direct service industries and displaces the output of Northwest thermal plants or thermal plants in the Southwest, primarily in California. This section of the draft plan explores higher-valued uses for this energy than serving the California displacement market, which is the largest customer of nonfirm energy from the Northwest.

Northwest nonfirm energy, in conjunction with a back-up resource, can meet firm loads in this region more cheaply than coal and other high-cost alternative resources can. This combination resource has been characterized in the past as "firming nonfirm" or "nonfirm strategies." While there are a number of alternatives for the back-up resource, including purchased power and contracts for use of energy from California thermal plants, the Council's analysis focused on two easily characterizable technologies, simple-cycle and combined-cycle combustion turbines, sited in the Northwest and burning natural gas.

Summary of Results

The Council's study showed that with expected gas prices at least 3,000 megawatts of combined-cycle generation could be used to firm the Northwest's nonfirm energy cost-effectively, compared with coal plants. Given the capital costs in the 1989 Supplement to the 1986 Power Plan, simple-cycle combustion turbines did not appear competitive with combined-cycle plants. However, this result is sensitive to gas prices. The optimum amount of turbine generation declines as gas prices increase, dropping to about zero (compared with coal) if gas prices climb about 20 percent above the expected gas price.

Availability of gas and effects of availability on price are important issues. Based on public comment and the results of a contractor's report on gas prices and availability, the Council has limited the amount of turbines in the draft portfolio to 1,000 megawatts before the year 2000 and 1,500 additional megawatts after that.

Background: The Northwest Hydropower System

Hydropower dominates the electrical power system in the Pacific Northwest, making the region unique in the United States. The hydropower system produces approximately 65 percent of the total electricity used by the region. Even with demand growth at the Council's high level, hydropower would still produce almost half the region's electricity at the turn of the century.

There are two key characteristics to the Northwest hydropower system. First, it varies widely in annual energy capability, depending upon rainfall and the snowpack accumulated in the region each year. The average annual output of the hydropower system since recordkeeping began in 1879 (and including the effect of the Council's water budget[19]) is approximately 16,400 megawatts. This is about 4,100 megawatts, or 33-percent, greater than the critical period energy capability. During a good year, the annual capability can be as much as 50-percent greater than critical period capability. "Critical period" refers to that sequence of low water conditions during which the lowest amount of firm load can be carried. The energy that can be generated during the critical period is called "firm" energy. Energy that can only be generated when water conditions are both better than critical conditions and sufficient to refill system reservoirs is called "nonfirm" energy.

A second, equally important characteristic of the Northwest's hydropower system is that the variation of flows within the year can be even greater than the variation across water conditions from year to year.

More than half the annual firm energy from the Northwest hydropower system comes from natural streamflows; less than half comes from reservoir storage. Figure 8-16 shows the variation in natural streamflow at The Dalles, Oregon, on the lower Columbia. The relatively low amounts and low variability of natural streamflows between August or September and the onset of the spring runoff in March or April are important in considering the risks that can be taken in using the reservoir storage. (The 10, 25, 50, 75 and 90 percent lines represent percentage of time the flow is equaled or exceeded on that particular day. These lines are based on 10-day mean values.)

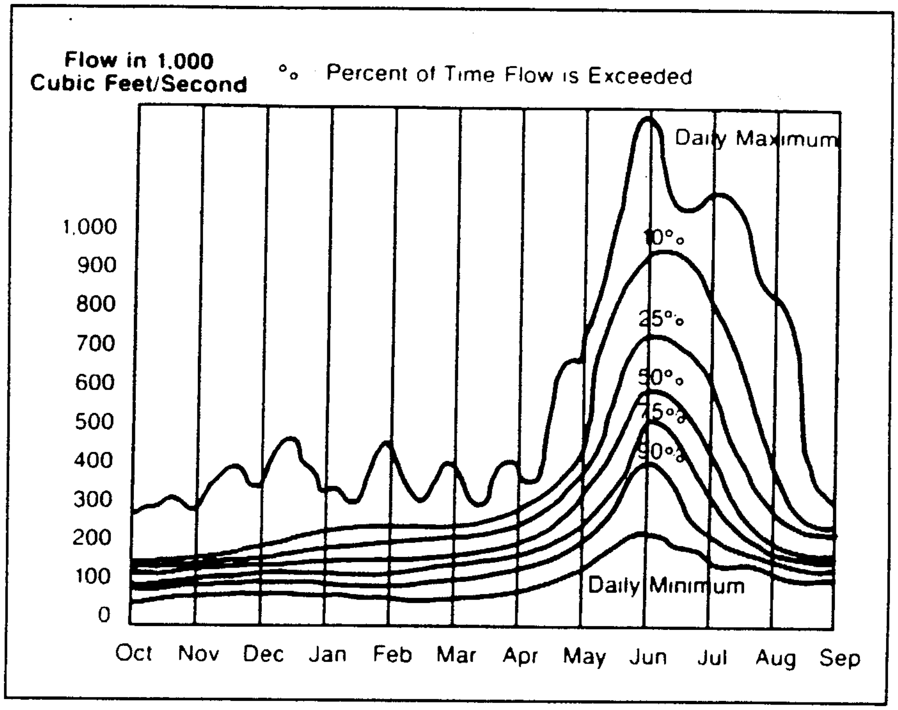
Historically, the Columbia River discharges about 73 percent of its natural runoff between April and October, and only 27 percent in the November to March winter period, when electrical loads are highest. This ratio of 73:27 has been altered by upstream storage projects so that the regulated flow matches the pattern of the region's loads. However, the river and its storage system are managed for purposes besides electricity generation. Flood control, irrigation, fish and wildlife requirements, recreation and navigation may limit the availability of upstream storage for power generation.

The reservoir storage itself is significantly limited. A large part of the hydropower system water supply comes from the snowpack in the upper Columbia and upper Snake river basins, in the mountains of British Columbia, Montana and Idaho. However, only 40 percent of even the average January to July runoff is storable in the system's reservoirs. This means large portions of the total annual water supply come during the spring runoff from April through July. Moreover, most of the water from the melting snow must pass through the generators or over the spillways if it cannot be used in the springtime because it cannot be stored for use in the following fall and winter, when demand is higher.

19./ The water budget is a volume of water released from upriver dams on the Snake and Columbia rivers to coincide with and aid the downstream migration of young salmon and steelhead each spring and early summer.

Columbia River Flow

Figure 8–16
Average Daily Columbia River Natural Flow at The Dalles, Oregon



Nonfirm Energy Availability

Figure 8–17
Probability of Nonfirm Energy Availability

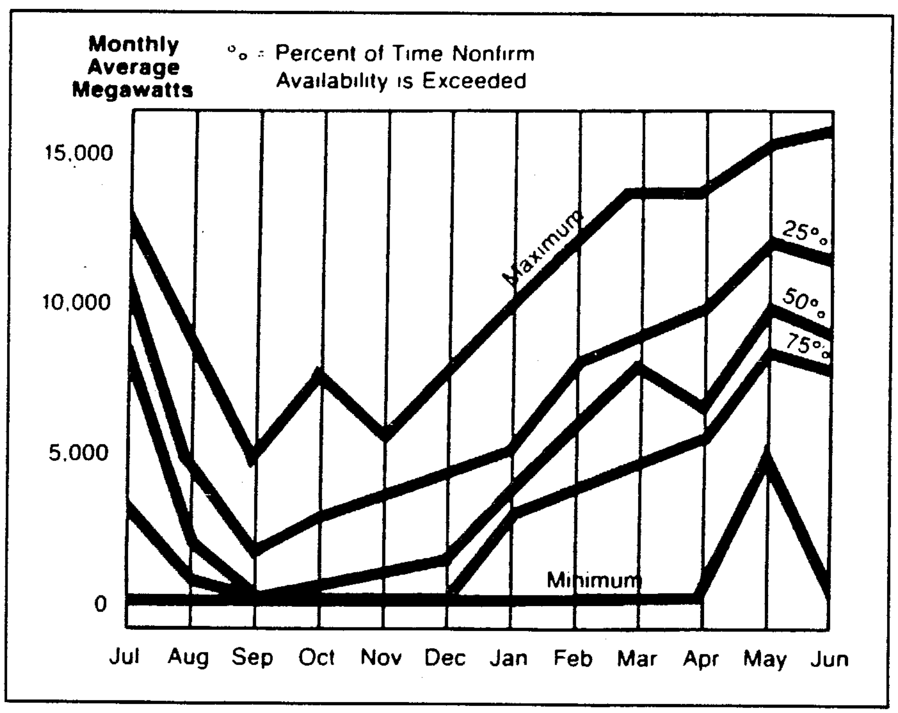


Figure 8-17 shows the amount of electrical energy available at various probability levels above the critical period quantities over the 102-year historical record. The variability of the hydropower system has major effects on the economics of other existing and new resources, because it influences the way they operate.

Nonfirm Energy Uses

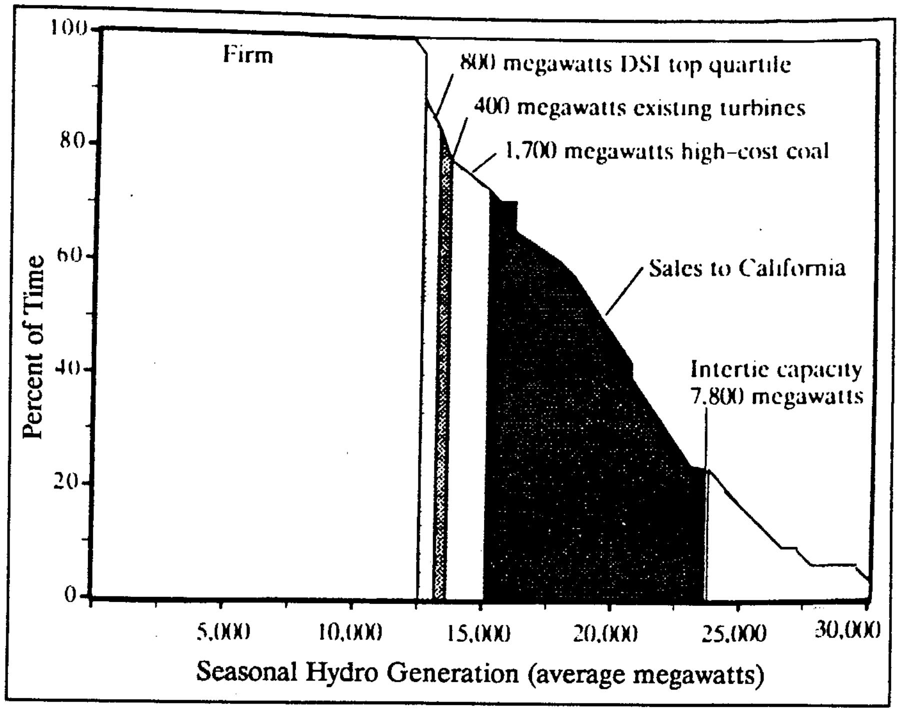


Figure 8–18
Duration Curve of Nonfirm Energy and Uses

Figure 8-18 shows the above information in a slightly different form. It shows the percent of time various amounts of nonfirm energy (averaged over seasons) are available and the uses to which they are currently put. These different uses are described in more detail below.

Background: Existing Uses of Nonfirm

Currently, there are three major uses of Northwest nonfirm energy. The first is to serve the interruptible or top quartile of Bonneville's direct service industries. The direct service industry load is divided into quartiles, and a different set of restriction rights applies to each of the quartiles. The main division, however, is between the first, or top, quartile for which firm resources are not planned, and the lower three, which are firm loads for planning. However, Bonneville operates its system to serve the top quartile as if it were a firm load, while retaining the ability to restrict service to it in order to avoid restricting service to firm loads.

This "as if firm" operation is achieved in the fall of the year by, in effect, borrowing water from future periods (following spring or following year) in the expectation that sufficient water will be available from the spring runoff to both refill the reservoirs and repay the borrowing by making up for the earlier reservoir draft.[20] After January, the direct service industries have priority access to Bonneville nonfirm to serve their top quartile loads. If there is insufficient runoff, the top quartile will be curtailed and the third quartile (by convention) will also be curtailed to repay the debt incurred by previous service to the top quartile. In this way, a higher level of service to the direct service industries is achieved while still effectively serving it only with nonfirm energy. When Bonneville has surplus firm energy available, it may use that to serve them. In this case, there is no liability for third quartile curtailment, as there is with energy borrowing techniques. When nonfirm is not available, the industries may request that Bonneville purchase industrial replacement energy for them at their direct expense.

The second use of nonfirm energy is to displace Northwest thermal plants. Existing combustion turbines on investor-owned utility systems could be shut down, using cheaper nonfirm energy, from their own hydropower systems or nonfirm purchased from Bonneville or generating public utilities. While these existing turbines generally were purchased to cover short-term energy deficits in the late 1970s rather than being part of a strategy of firming nonfirm, they could operate exactly as the turbines examined in this study, and are assumed to do so, within the operating limits currently set by their owners. Nonfirm also can be used to displace higher-cost coal plants, such as Boardman in eastern Oregon and Idaho Power's Valmy plant in northern Nevada.

Third, the remaining nonfirm is sold to Southwestern utilities, principally in California, to displace gas and oil generation. The Northwest's revenues from nonfirm sales to California can run into several hundred million dollars each year, with good water conditions. For instance, in 1985, Bonneville alone earned more than $400 million from sales outside the region, the bulk of it to the three largest California utilities, Pacific Gas and Electric, Southern California Edison and the Los Angeles Department of Water and Power. The average revenue was 2.27 cents per kilowatt-hour. In recent years, California gas prices have been lower and there has been little Northwest nonfirm available from the hydropower system due to the extended drought.

Nonfirm is sold either directly by utilities, or purchased from Bonneville by non-federal thermal generators and used to meet Northwest loads. In the latter case, the Northwest thermal generation, which would otherwise have been run to meet Northwest loads, is instead run to reduce generation at higher cost gas and oil plants in California. These latter "displacement" transactions can take place

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20./ "Borrowing" covers three specific practices with requirements that differ only slightly. Shifting firm energy load carrying capability (FELCC) borrows from the second or later years of the critical period and puts the third quartile return obligation into the spring of a later year after use by the first quartile. Advance energy (or provisional draft) has a return obligation that depends on whether return will allow reservoirs to refill or not. If return will allow refill, then return is required the first spring after use. If the runoff is so bad that it will not allow refill, then the obligation is deferred to a later spring. Flexibility energy is required to be returned the first spring in all cases.

only when the Bonneville nonfirm rate is significantly lower than the California market price.

Study Results

The general conclusions of the study can be seen in Figure 8-19. This shows curves of the benefits of simple-cycle and combined-cycle turbines compared with coal plants, as a function of total megawatts. The curves were constructed by comparing 500 megawatts of turbines with 500 megawatts of coal, then 1,000 megawatts and so forth. The benefit that is plotted is the lower total system cost that occurs by having turbines instead of coal plants in the system. Since these curves flatten out or turn over, they indicate that additional 500-megawatt units have lower value than the initial units. The point at which the curve turns over is the point at which the last megawatt of added turbine capacity has exactly the same cost as the last megawatt of added coal capacity. Each additional megawatt would then have negative value, indicated by the downward sloping portion of the curve. The fact that the combined-cycle curve has not turned over at 3,000 megawatts indicates that the optimum number is beyond that point, given the assumptions in the study.

Turbine Cost–Effectiveness

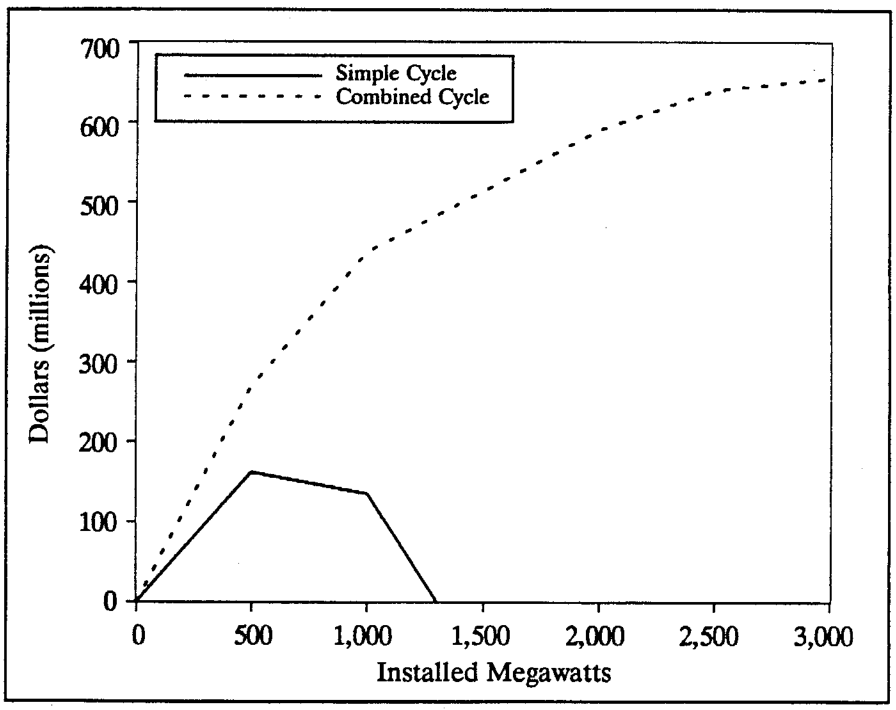


Figure 8–19
Cost–Effectiveness of Turbines Compared to Coal

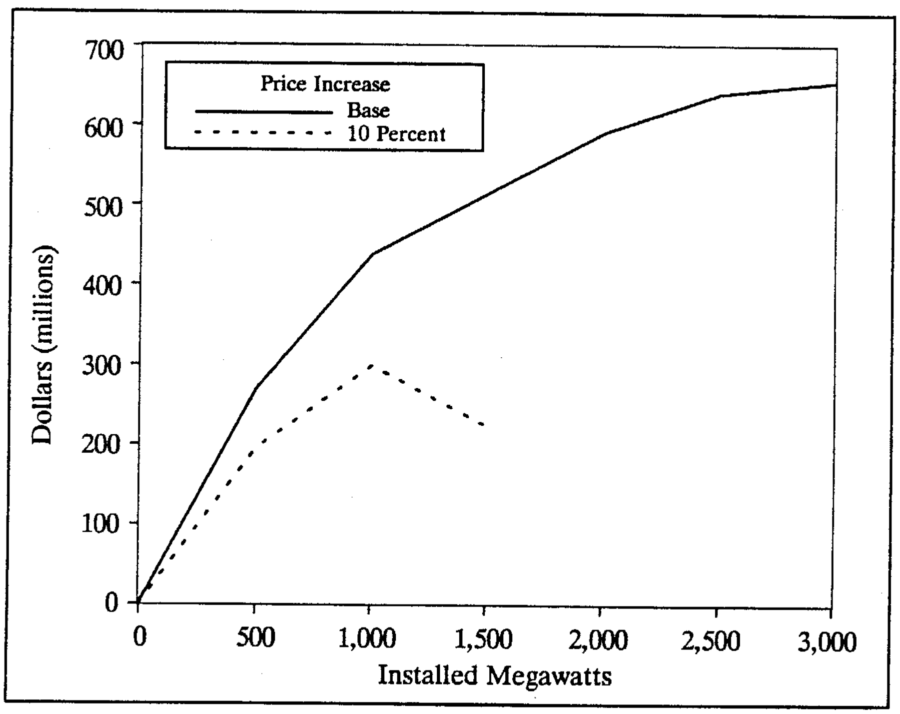
Figure 8-19 also shows that combined-cycle turbines are more cost-effective than simple-cycle turbines at all megawatt levels. This differs from what the studies for the 1989 Supplement to the 1986 Power Plan showed. Those studies concluded that, for approximately the first 1,000 megawatts of firming resources, simple-cycle turbines were better than combined-cycle turbines. The relative costs of the two technologies have been re-evaluated since then, however, and the capital costs of simple-cycle turbines have increased substantially relative to combined-cycle turbines. As data on the cost and performance of aircraft-type simple-cycle turbines are further updated, it may turn out that they are a reasonable alternative to the industrial-type turbines used in this analysis. If so, they may have cheaper capital costs, at the expense of higher operating costs and may cost-effectively replace some of the combined-cycle turbines in the portfolio.

Gas Price Sensitivity and Availability

Price and availability of gas are key to the discussion of firming nonfirm with turbines. This study used the hybrid gas price data from the 1989 supplement, calculated using 50-percent firm and 50-percent interruptible gas in the mix. Sensitivity scenarios were based on that initial set of prices, and the California market price was adjusted in a roughly comparable way. The capital cost of the turbines included a fuel inventory charge for a back-up 14-day supply of fuel oil, to cover periods when gas might be interrupted, such as the extended cold spell of February 1989.

Gas Price Effects

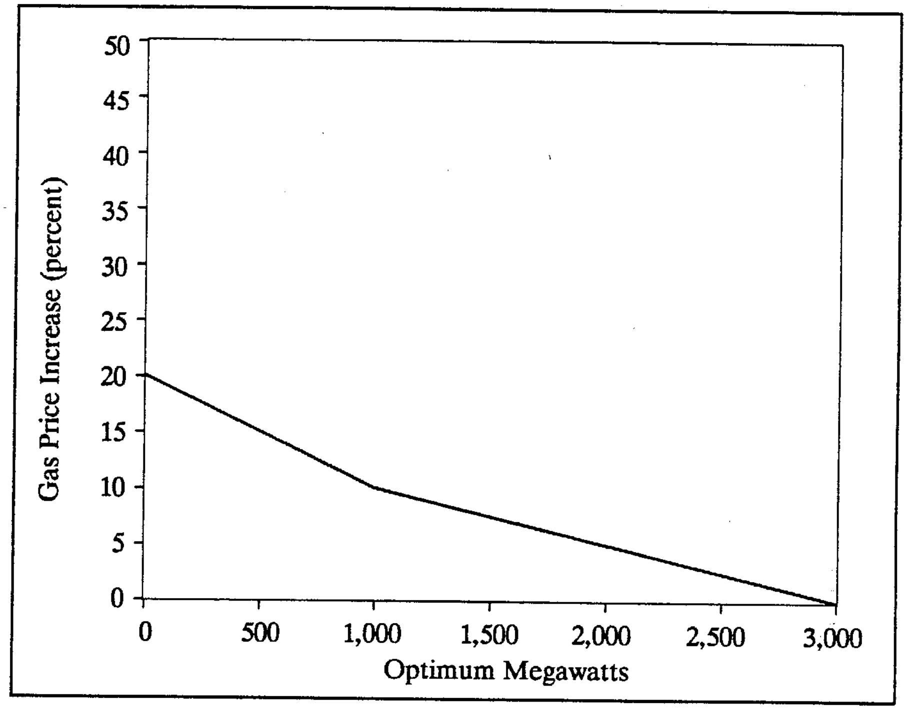
Figure 8–20
Effect of Gas Price on Turbine Cost–Effectiveness



The sensitivity to gas prices is shown in Figure 8-20. A 20-percent increase, while not shown in Figure 8-20, is the value that causes the optimum turbine capacity to drop to about zero. Based on several specific comparisons, the staff developed the graph in Figure 8-21. This graph shows the approximate optimum amount of turbine capacity (representing the top of the curves described above) as a function of gas prices. As gas prices increase, the optimum amount of turbine capacity decreases. This figure also indicates the amount of turbine capacity that is cost-effective for any level of gas price increase over the base-case values.

Gas Price Effects

Figure 8-21
Optimum Turbine Megawatts per Gas Price Increase



The studies initially assumed unlimited availability of gas at these prices to supply up to 3,000 megawatts of additional turbine energy capability, above the approximately 400 megawatts currently declared on the existing system. This cut-off point, due to availability of gas supplies, was estimated during the process of updating the 1986 Power Plan in the summer of 1988. Since the time these studies were done, the Council has had an independent contractor review the Northwest gas supply situation.[21] The results of that study will be summarized in the course of the discussion below.

The contractors concluded that there was a very large gas reserve base in western Canada at reasonable prices. The primary constraints are transmission capacity to deliver that gas to the Northwest, and the issues raised by the potential usage pattern of the gas. Use of natural gas for backing up nonfirm hydropower presents an unusual gas supply problem. Because these generating

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21./ *Future Natural Gas Cost and Availability in the Pacific Northwest*, Economic Insight, Inc. and Arlon R. Tussing Associates, Inc., January 29, 1990. It is available to interested parties as Council publication #90-4.

plants would operate only when nonfirm energy is unavailable, they would usually operate only for several fall months per year, and sometimes would not operate at all during the year. On the other hand, during dry years, they might have to run at nearly full capacity for more than a year. (Because energy, not capacity, is the reason for operating these plants, short shutdowns could be tolerated.)

Representatives of the gas industry have suggested that these plants would require the reserved pipeline delivery capacity of firm service. But it should be possible to market some of this reserved delivery capacity during those periods when plant operation is not required, thereby offsetting part of the fixed delivery costs. Moreover, because these generating plants could be shut down for short periods of time, even during poor water years, some of the peaking service costs associated with firm gas contracts could be avoided.

An alternative to this arrangement is to rely entirely on interruptible gas with back-up oil for peak-period gas interruptions. Because the time pattern of potential gas use for turbines is different from the time pattern of firm gas use, there will generally be nonfirm transmission pipeline capacity available when the turbines will have to run. The turbines are most likely to run from the late summer through December, which is when the expected availability of nonfirm hydro energy is the lowest. This can be seen by referring back to Figure 8-17, earlier in this chapter.

On the other hand, the firm gas demands on the pipelines peak with the heating season in December through March. Moreover, the gas transmission system is sized, and firm contracts are signed, on the basis of the expected maximum daily peak demand on the system. Typically, in the Northwest, these demands come during one-week to two-week cold spells, rather than lasting over periods of several months. These are the kinds of interruptions in fuel supply that could be backed up by oil in storage at the site of the turbine.

Interruptible gas transmission capacity that is currently available will be used up gradually as firm gas demands grow. However, the Northwest sits between the western Canadian gas fields and the large California gas market. This market is most likely to be the one that drives the expansion of the gas pipeline capacity, rather than demands in the Northwest. It is not reasonable to expect that existing pipeline capacity will be a permanent constraint.

Several proposals to reduce risks associated with increased use of natural gas have been advanced. These include use of combined-cycle generating plants that could be converted to coal gasification; purchase of long-term contracts with gas producers; equity participation in gas fields, and limiting new gas-fired capacity to some proportion of new resource requirements (similar to California's resource diversity policies). In addition, there are alternatives involving capacity/energy exchanges with California or Desert Southwest utilities that would make back-up energy available without the constraints that are linked to pipeline capacity in the Northwest. These are discussed again below.

It is widely agreed that there is abundant natural gas available for the long term at the producer level. However, natural gas is obtained outside the region; is subject to major price uncertainty, particularly as gas becomes a fuel of choice nationally (due to its flexibility and environmental advantages); and is subject to transportation constraints. Consequently, the Council has chosen to limit the amount of turbine energy (or its substitutes, discussed later) for backing up the region's nonfirm hydro energy before the year 2000 to 1,000 megawatts. The remaining 1,500 or so megawatts will be kept until later, under the assumption that the gas supply situation may become clearer after the turn of the century.

Capital Cost Sensitivity

The Council also examined the sensitivity of its study results to relative capital costs of turbines as well as to operating costs. Results of these so-called "sensitivity studies" are shown in Figure 8-22 and Figure 8-23 in a similar format to the gas price sensitivity graphs.

Figure 8-23 should be read with two qualifications in mind. First, the shape of the curve is only approximate, because it was based on estimates of the peaks, in Figure 8-22, as if the curves were smooth. Second, the value of zero for 3,000 megawatts is artificially low, since the actual base-case curve is still rising at 3,000 megawatts, so the peak and the zero point are actually further to the right than 3,000 megawatts.

The sensitivity of turbine net benefits to coal plant capital costs is shown in Figure 8-24 in a format similar to that of Figure 8-22.

The sensitivity of turbine net benefits to coal plant financing cost is shown in Figure 8-25. The base case shows the financing costs recently adopted by the Council. The line labeled "Old Assumptions" shows the financing costs, one percentage point higher, that were used in the 1989 supplement. Changing the financing costs by one percentage point changes the annual capital costs by approximately 13 percent.

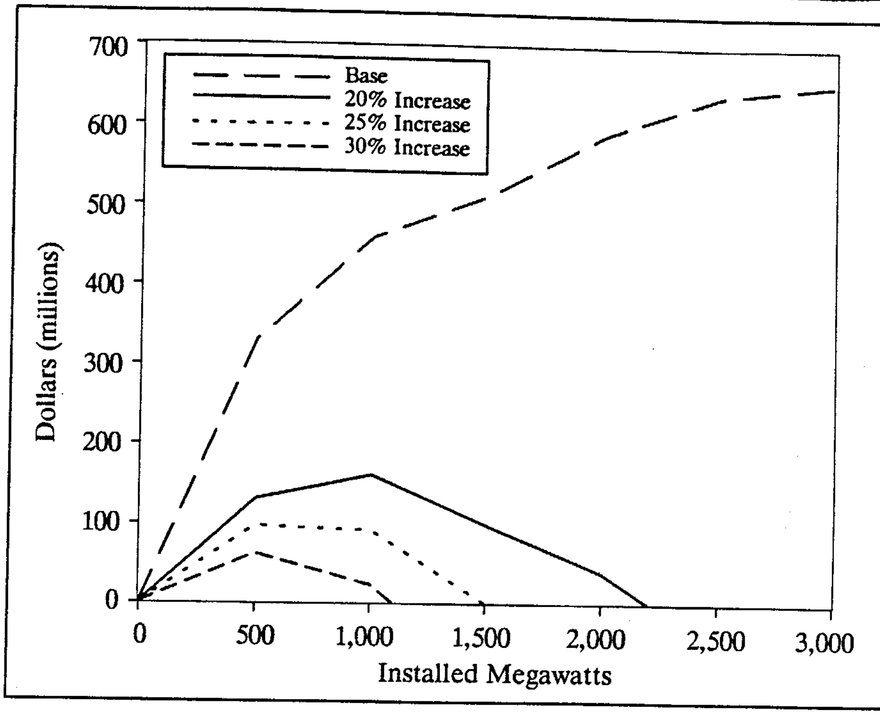
Capacity Factors

Capacity factors represent the amount of energy that a plant produces in a specific period compared with the amount it was capable of producing. It is a quick check on whether the operation, particularly of turbines, is being modeled appropriately, since the historical monthly availability of nonfirm to displace the turbines is well known. Figure 8-26 shows the incremental capacity factors, as a function of total capability, for the combined-cycle and coal plants. The capacity factors indicate that the modeling is quite conservative with respect to the benefits of turbines. The increase in capacity factor for the turbines as the total installed amount of turbines increases is a reflection of the decreasing availability of nonfirm to displace them, which causes them to run more.

Figure 8-27 shows the average monthly capacity factor for the two plant types.

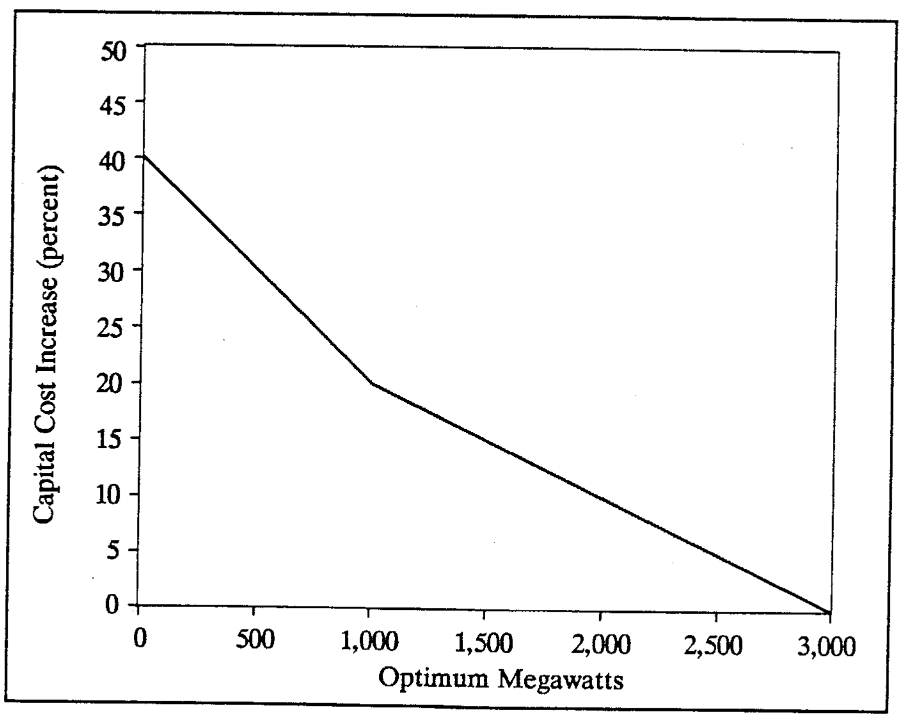
Capital Cost Effects

Figure 8–22
Effect of Turbine Capital Cost on Cost–Effectiveness



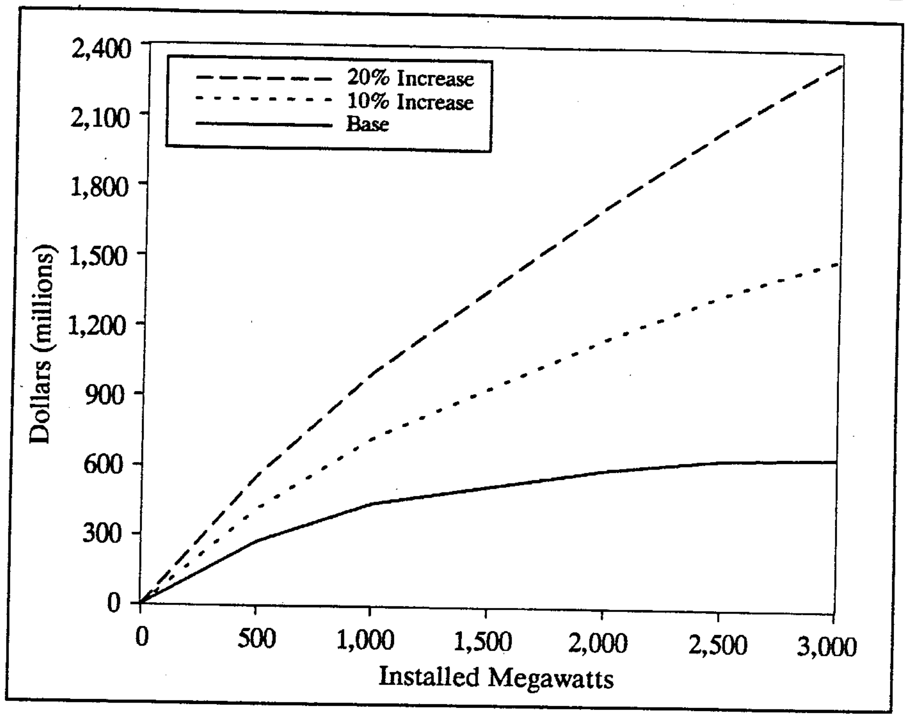
Capital Cost Effects

Figure 8–23
Optimum Turbine Megawatts per Capital Cost Increase



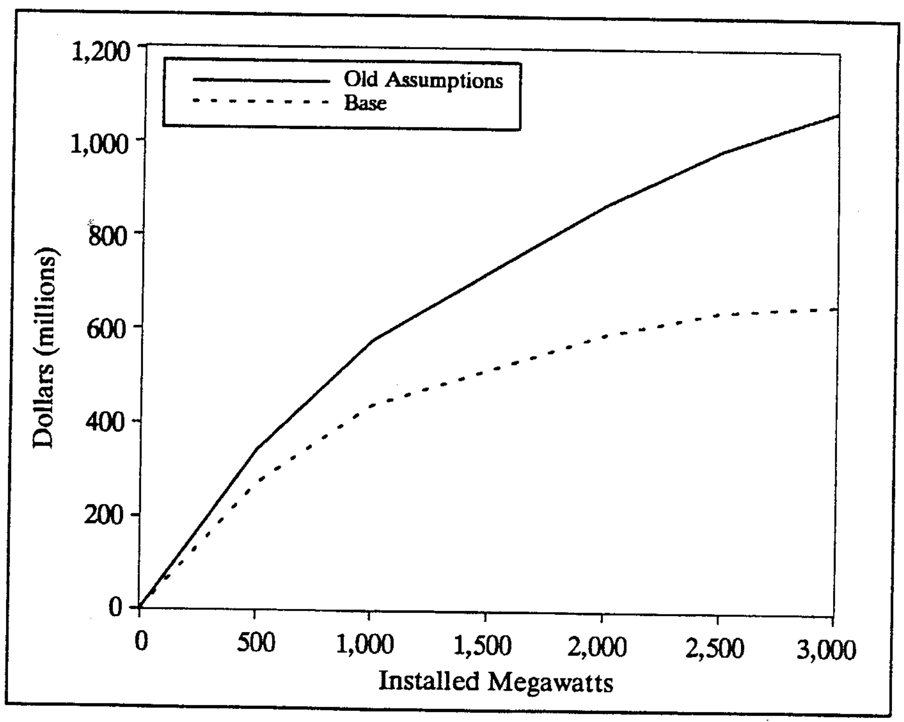
Capital Cost Effects

Figure 8–24
Effect of Coal Capital Cost on Cost–Effectiveness



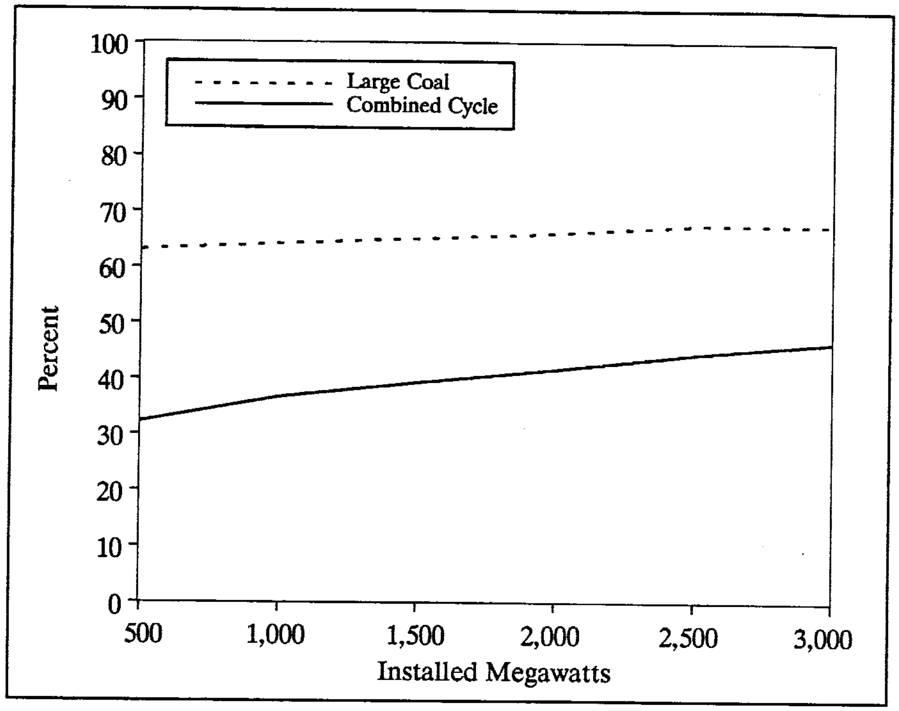
Capital Cost Effects

Figure 8–25
Effect of Coal Financing Cost on Cost–Effectiveness



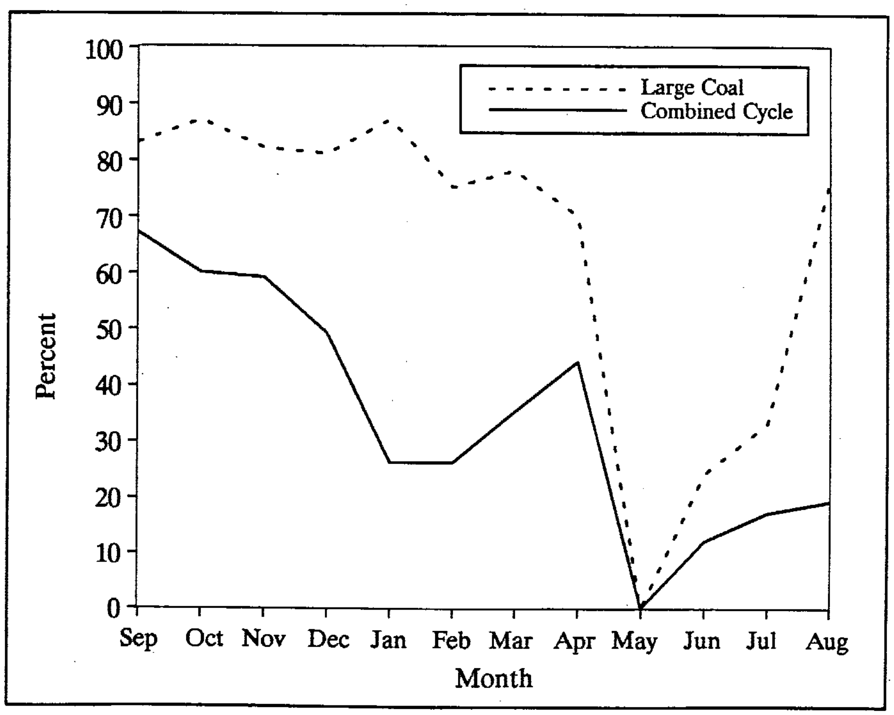
Capacity Factor

Figure 8-26
Incremental Capacity Factor per Amount of Installed Megawatts



Monthly Capacity Factor

Figure 8-27
Monthly Capacity Factor for 500 Megawatts of Installed Resource



Other Issues

British Columbia Hydro Availability and Price

The System Analysis Model contains a provision for modeling the impact of sales by BC Hydro on Northwest operations and California sales. As currently modeled, BC Hydro has very little impact on the operation of combined-cycle turbines. Nonfirm from BC Hydro does not displace Northwest combined-cycle plants, although it does displace simple-cycle turbines. Even with the effect of BC Hydro, however, the simple-cycle turbines did not appear to be cost-effective compared with combined-cycle plants, due to their relatively high capital cost and low efficiency.

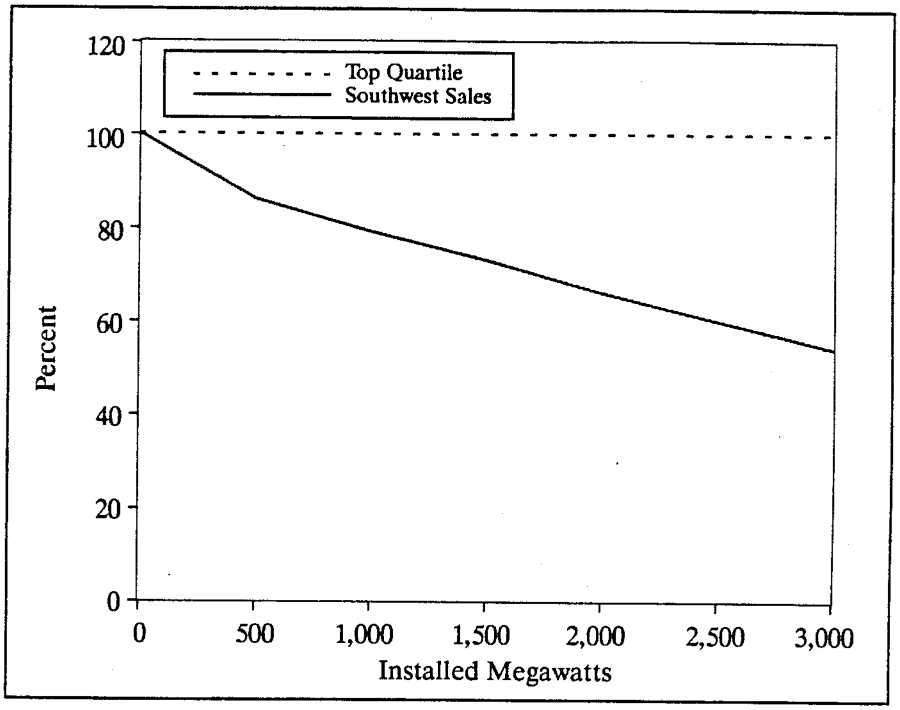
Direct Service Industry Top Quartile Service

Combustion turbines can compete with the direct service industry top quartile in two ways. First, the borrowing techniques that serve the top quartile in the fall also can be used to displace turbines if adequate backup, analogous to the third quartile curtailment right, is available. This backup could be in the form of extra turbine capacity, that could be run to bring reservoirs back up to the level they would otherwise have reached without the borrowing, in the event there is no nonfirm energy in the spring. This operation of turbines ahead of industry service is prohibited to Bonneville under its power sales contracts, but does not apply to the non-federal utilities using their own portions of the hydro system. These studies did not include this kind of operation for the turbines, since they appear to be cost-effective without it.

The second potential conflict is in priority of access to nonfirm in the period following January. There may be an argument about the interpretation of the direct service industry power sales contracts on this point, if the turbines are owned by Bonneville. On the other hand, the priority in this period is likely to make much less difference, because there generally is either enough nonfirm to meet both requirements, or not enough to meet either. The number of times in which turbines and the top quartile could compete for nonfirm is much smaller in the period after January than before it. In any case, the studies gave priority access to nonfirm to the industries in this period as well. The intention of the studies was to have no significant impact on service quality to the industries' top quartile.

Top Quartile Service and Sales

Figure 8–28
Change in Top Quartile Service and California Sales per Amount of Combined–Cycle Turbines



Impact on California Sales

When the Northwest uses nonfirm to displace turbines, it reduces sales to California. But when the nonfirm displaces Northwest coal plants, these plants are still available to generate energy for the California market, where they, in turn, displace gas generation. The nonfirm revenue that is forgone when turbines, instead of coal plants, are used in the Northwest is part of the cost of the turbines, and is accounted for in the study results. Figure 8-28 shows California sales with combined-cycle turbines compared with a base case having no new loads or resources. It also shows the effects on top quartile service, discussed above.

Increased reliance on turbines in the Northwest would shift environmental impacts between the Northwest and other areas that supply energy to California. Use of hydro energy to shut down turbines in the Northwest would reduce air quality impacts in the Northwest, compared to a coal plant scenario in which Northwest coal plants run to meet nonfirm markets in California. It would, however, tend to increase air quality impacts in California or in the Southwest, which is the primary alternative supplier of displacement energy to California.

Hydro System: Water Budget Flows and Refill

The Council also reviewed the effects of turbine operation on water budget flows and ability of the system reservoirs to refill. There was no impact on water budget flows or refill. No impacts would be expected, because the operation was modeled to stay within existing system constraints, including both refill and flow constraints.

One of the reasons that firming the Northwest's nonfirm makes economic sense compared to building coal plants is because the nonfirm revenue from California is often limited to Bonneville's standard nonfirm rate, a rate that is forecast to stay constant or decline in real terms, though the price of gas is forecast to increase in real terms. Thus, over time, more money could be saved by using nonfirm to displace gas generation serving Northwest loads than could be earned using it to displace gas generation serving California loads.

The Council recognizes that this increased value also increases the incentive of system operators to shape hydropower operation through time to maximize the displacement of the gas generation. The Council has begun a review of the water budget and will change it if it is determined to be inadequate. The Council expects the flow levels in the Columbia River Basin Fish and Wildlife Program, or any flow levels determined to be appropriate under the Endangered Species Act, to be firm constraints on hydropower system shaping.

Additional flows that are not shapeable to power operations, like the water budget, may be required to meet fishery requirements, either in the spring migration season or in other times of the year. These flow requirements, by converting firm hydro energy to nonfirm energy, increase the potential value of turbines compared to coal plants by increasing the amount of time, on average, that the turbines can be displaced. The more nonfirm that is available on the system, particularly if it is available in seasons and water conditions in which it was not previously available, the more cost-effective a given megawatt level of turbine capacity becomes and the higher that level will go.

Recent Studies by Others

Bonneville also completed a study of this issue, leading to the inclusion of up to 1,500 megawatts of firming resources in its 1990 Resource Program. That study, like this one, was done by comparing simple-cycle and combined-cycle turbines with coal plants. However, in practice, Bonneville believes that about 500 megawatts of the 1,500 could come from contracts with extra-regional utilities, while the remaining 1,000 megawatts should come from combined-cycle turbines.

Bonneville's studies looked only at the federal system, so they compared plants with federal financing, displaced only by federal nonfirm. Bonneville has about two-thirds of the region's nonfirm. Its study examined varying amounts of turbine capacity only up to 1,500 megawatts. If all else is equal, the Bonneville studies should imply approximately 50 percent more turbine capacity is cost-effective for the region as a whole than for Bonneville, based on nonfirm availability alone. Differences in financing costs also should make a difference, since this study assumed investor-owned utility financing at higher costs than the federal financing assumed by Bonneville, and capital costs affect coal plants disproportionately to turbines.

The Bonneville studies are generally consistent with this study, although this one found larger benefits for turbines at comparable megawatt levels. The two studies were done with different models and methods, and it is difficult to compare the results precisely.

Cost and Rate Variability

One issue that concerns utilities is rate variability due to operating cost swings when there is oil or gas generation on the system. While this analysis has not looked directly at rates, it has examined the question of cost variations for the two resource types, coal plants and turbines. Bonneville's analysis for the 1990 Resource Program also has looked at these issues, and its results can be compared with the Council's.

The question is raised largely because of the experience of the late 1970s, when oil prices were extremely high compared with then-current rates. Utilities are concerned about their exposure to significant variations in cost from year to year due to the variations in water conditions common in the Northwest. Their customers are concerned as well, particularly those residential, commercial and industrial customers for whom short-term budgets are constraining. Generally in economics, a wide range of uncertainty is more costly than a narrow range. The Northwest already faces water uncertainty in the swings in its nonfirm revenues.

There are several considerations here, however, and the results may not be obvious. First, cost (or rate) stability and net revenue stability are not the same things. For instance, Bonneville's concern with its financial condition and its ability to maintain its treasury repayments could drive it in the direction of focusing on net revenues rather than simply costs or rates, when it considers stability issues.

Because Bonneville's financial structure is characterized by such a high percentage of fixed debt, it has little cushion with which to absorb the results of bad years. In the past, it has deferred treasury repayments when in such circumstances, but this practice is generally considered unacceptable today outside the most dire circumstances. One of Bonneville's current financial criteria for setting rates is that it have a 95-percent probability of making annual treasury payments on schedule. That concern has led to the cost-recovery adjustment mechanism in the current rates, which is a formula to adjust rates upward to maintain net revenues, and to the goal of accumulating net revenues to create a cushion.

An investor-owned utility, on the other hand, is cushioned by its stockholders who can absorb swings in net revenues, although the utility would generally like to minimize the swings. This may apply to some generating public utilities as well, if their governing bodies and statutes allow the accumulation of net revenues as operating reserves.

The second factor to consider is the relative magnitude of fixed costs in the utility's cost structure. This has two effects. First, a utility such as Bonneville, whose thermal plants are both nuclear and thus are generally treated as must-run plants, sees different costs when making decisions about nonfirm sales than a utility with coal plants, such as the investor-owned utilities and some public generators. This will show up in different effects of water variation on the utility's costs when comparing coal plants and turbines.

Generally, the effects of water variations have opposite signs for coal plants and turbines. Good water will provide extra secondary revenues from coal plants, which will cover their operating costs and provide an additional revenue margin to reduce fixed costs on the system. In the turbine case, it will allow the saving of the entire operating cost, but will not provide any sales and thus extra margin. However, if the savings in operating cost for the turbine are greater than the margin provided to reduce fixed cost for the coal plant, the reduction in total cost is greater with the turbine than with the coal plant, when the utility experiences good water conditions.

When poor water conditions prevail, the sum of the operating and fixed costs of the turbine are greater than the sum of the operating and fixed costs of the coal plant, and thus the coal plant is least expensive.

Therefore, there will be a range of total costs for both the coal plant and the turbine that will depend on water conditions. The issue here is whether the range is bigger for one resource than for the other, and if it is bigger, is it bigger on both sides, just the negative side, or just the positive side?

Bonneville and the Council both examined the effects in a single operating year (2001 or 2006) of high and medium gas prices and good and bad water conditions on the choice of a coal strategy or a turbine strategy. The results were generally consistent, but not completely so. The differences are difficult to reconcile, since Bonneville and the Council used quite different modeling approaches. The results of the Council's studies are summarized in Figure 8-29.

Both studies found a wider range of variation in costs for turbines than for coal plants, going from good water to bad water, and the range increased for both studies when going from medium to high gas prices. Low gas prices were not examined in the Council studies, but would show a larger benefit to turbines. While the studies showed a small net cost to turbines in the worst case--high gas prices and poor water conditions--overall, they showed a benefit to turbines.

This overall benefit in the Council studies occurred, because the total costs of coal plants and turbines in the early 2000s are approximately equal. What the coal plant gains in lower fuel and operating cost, it loses in higher capital cost when, under poor water conditions, both plants are running at high capacity factors and neither is displaced by nonfirm.

Net Benefits

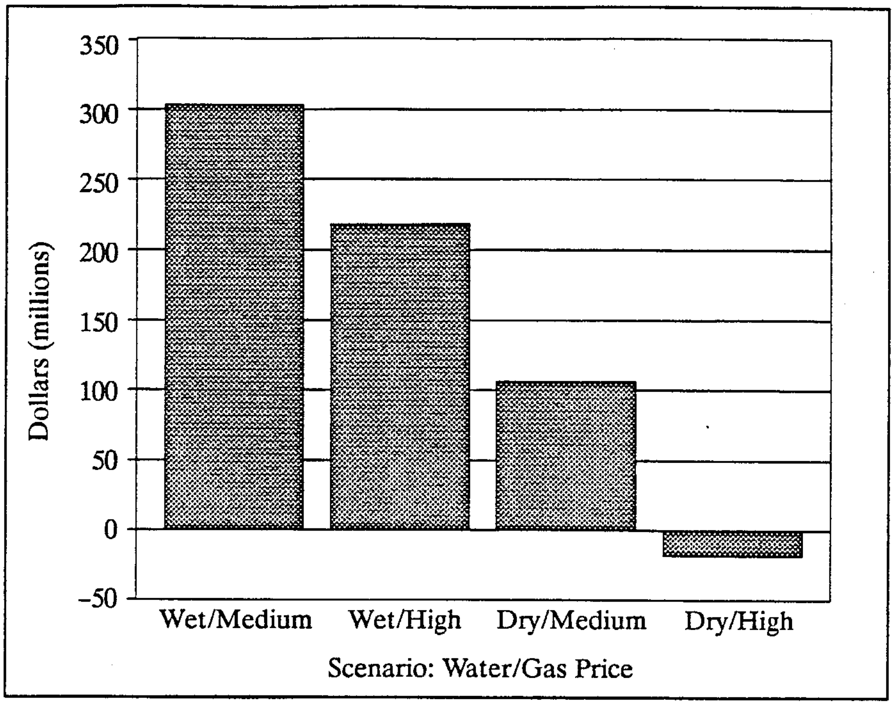


Figure 8–29
Effect of Runoff Volume and Gas Price on Turbine Cost–Effectiveness (2,000 megawatts combined cycle, year 2006, 1989 dollars)

When good water conditions are encountered, however, the additional revenue from nonfirm sales of the coal plant are not sufficient to offset the cost savings from shutting the turbine down entirely. This happens because, typically, California utilities do not pay the Northwest the entire decremental cost they save when they buy Northwest nonfirm. They generally pay some lower percentage of it, assumed to be a maximum of about 70 percent of it in these studies. In addition, during good water conditions, the price is typically lower than the maximum California would otherwise be willing to pay as well. Thus, in the Council studies, turbines look about even with coal plants in bad water conditions and substantially better in good water conditions.

It should be noted that the early years of the plants' lives provide the most favorable comparison for turbines. This occurs because the largest component of the coal plants' cost, the original capital cost, is fixed at its construction date and declines from that point until retirement of the plant. For a turbine, the largest component is fuel cost, which continues to escalate from the date of construction, and at a faster rate than does the fuel cost of the coal plant. These factors explain why this example year shows overall benefits to turbines with high gas prices while the earlier description of gas price sensitivity showed high sensitivity to gas prices on a lifetime present value basis.

Bonneville's studies found that turbines were somewhat more costly with high gas prices and dry conditions than were coal plants, although with medium gas prices the turbines were the lower cost. These studies employed different models and approaches, so they are difficult to compare.

Risk Management Strategies

Water and gas prices are not the only risk factors for the region, particularly when the focus is on net revenues. A utility such as Bonneville, which has primarily fixed costs, is more vulnerable to load and sales variability than it would be to cost variability. This became clear over the mid-1980s, when the overriding problem Bonneville faced was its ability to maintain its treasury payments when it was constrained in its ability to raise rates by elasticity considerations for direct service industry and California sales.

Low aluminum prices and, later, low California gas prices simply did not allow Bonneville to recover the costs it had intended to recover from sales to the direct service industries and to California. If more of its costs had been variable with sales, the costs would have dropped with the sales. Instead they remained constant in the face of declining sales and forced the prospect of having to raise rates as sales were declining, which led to concerns about a "death spiral" of ever-increasing rates and decreasing sales. Thus, it is clear from our recent experience that load and sales uncertainty are as important for analysis of turbines as water and gas price uncertainty.

While raising rates in the face of unexpectedly high costs from year to year is not an attractive prospect for either utilities or their customers, raising rates has a built-in feedback effect that can mitigate the problems with net revenues. As rates are increased, short-term sales will decline, and with them, the high short-term costs that are the problem.

Moreover, because utilities need to be able to meet loads at the peaks of business cycles as well as in the troughs of the cycles, weather-adjusted loads are likely to be highest at the times when the region's economy is at its healthiest. These are the times when rate increases have their smallest effect on the region's consumers. When the economy is suffering, loads also are likely to be down, and some generating plants are likely to be surplus. If high gas prices occurred at this time, the rate effects would be smaller, because the turbines would be less likely to be running to meet load.

Finally, coal gasification remains an alternative in the case of sustained high gas prices. While the incremental capital cost of adding gasification facilities is approximately the same as building a coal plant from scratch, the lead time is shorter and the resulting fuel cost is lower than would be true for a new, conventional coal plant. So, while capital can be substituted for expensive fuel in the high gas case, fuel cannot be substituted for expensive capital in the scenario in which the region sees declining gas prices and coal plants that cannot earn extra revenue in the nonfirm markets.

Northwest Institutional Issues

The institutional issues affecting these strategies to back up nonfirm in the Northwest revolve around the ownership of the nonfirm and the ownership of the turbines and other Northwest displaceable thermal plants. Approximately two-thirds of the nonfirm is generated on the Bonneville system. All the existing high-cost thermal plants are on the systems of investor-owned utilities, with one exception. The settlement agreement in the lawsuit over completion of Washington Public Power Supply System nuclear project 3 (WNP-3) provides for the operation of some of the investor-owned utility turbine capacity at Bonneville's expense, if needed to meet Bonneville's obligations under the settlement. Thus, the investor-owned utilities have an interest in Bonneville nonfirm being available at relatively low prices to displace their higher cost thermal plants. At the same time, the non-generating public utilities and direct service industries have an interest in Bonneville's nonfirm being priced relatively high, whether sold in the Northwest or in California, in order to help hold down Bonneville rates.

Further, any development of turbines by Bonneville would mean that the highest valued use of Bonneville's nonfirm would be to displace its own resource rather than any investor-owned utility resource. These considerations can make it more risky for an investor-owned utility to consider turbines as a long-term resource choice than it would be for Bonneville, even considering the nonfirm available on the investor-owned utility systems. This problem might be mitigated through investor-owned utility load placement on Bonneville associated with turbine acquisition by Bonneville, though the details would likely be subject to disagreement between public and private entities, depending on circumstances.

Other Turbine Resource Values

Combustion turbines or combined-cycle turbines have another value that is not directly related to their value in firming nonfirm energy to meet firm loads. This is their value in backing up other resources that might have uncertain output. For instance, to the extent that the Council considers a range of uncertainty in a resource's availability, use of turbines could be combined with lower estimates of availability, to guarantee the amount of firm output available using expected values for the resource. This might be particularly appropriate for resources, such as conservation, where the difference between minimum and expected estimates is due to disagreements about financial assistance, program design issues, and consumer or utility willingness to participate.

Another value was not considered previously by the Council is the value of peak, or capacity, reserves. While the Northwest is generally considered to be capacity surplus, there are areas, such as the Puget Sound region, where capacity problems are more likely than for the region as a whole, because of transmission constraints. Combustion turbines are one of the alternatives to additional transmission lines that are being considered by Bonneville for avoiding potential problems meeting load in the Puget Sound area.

Non-Treaty Storage Agreement

One issue that was raised during comment on this study has to do with the effect of the Non-Treaty Storage Agreement between Bonneville and BC Hydro on the availability of nonfirm energy and turbine displacement. The general effect of the new agreement, which would expand and extend in time an existing agreement, would be to convert approximately 300 megawatts of nonfirm energy to firm energy, with half the benefit going to each party. It was suggested that any amount of firming of Northwest nonfirm that is proposed in this plan and which is based on data and studies that do not take a new agreement into account, should be reduced by the amount of nonfirm that would be firmed as a result of the new agreement.

Although this proposal has not been analyzed using the Council's computer models, it does not appear to be correct. Implementation of the new agreement would generally only affect storage of the last increments of nonfirm, which would be otherwise spilled or sold in low-valued markets, for use in periods in which there is little to no nonfirm available. This operation is also done because storage (which changes flow patterns) of only these last increments of nonfirm would have minimal or insignificant effects on the flows for fish. Uses of nonfirm for meeting direct service industry loads and displacing turbines, on the other hand, represent the first increments of nonfirm use. It would appear that the only effect of the new agreement would be to reduce the availability of nonfirm energy to California, as it is put to higher-valued uses.

Alternatives to Combustion Turbines

Combustion turbines were studied, because they represent a conservative, well-known technology. There may be a number of alternative back-up resources that could be used in conjunction with nonfirm energy to meet additional firm loads. Bonneville has indicated in its 1990 Resource Program that it believes that 500 megawatts of backup could be available from extra-regional purchase arrangements.

Northwest utilities currently have declared approximately 400 megawatts of energy to be available from existing simple-cycle and combined-cycle turbines. However, the total capacity of these plants is almost 1,500 megawatts. Using the Council's assumptions for plant operating availability, these plants could produce more than 1,260 megawatts of energy, almost three times their declared level. The limitations are based on existing fuel contracts, site-specific limitations and utility operating desires. However, this extra in-region capability could potentially be part of the 3,000 megawatts of the new combustion turbine energy this plan describes as cost-effective. Repowering of the Hanford Generating Project with gas, which the Council and Bonneville have studied in the past, represents another possible alternative.

There are other alternatives for using the nonfirm, which would have somewhat different effects from those studied in this paper. Increasing the interruptible portion of the direct service industry load would not be a directly comparable alternative, because it would not meet the same load with the same degree of reliability. However, it does represent an alternative use of nonfirm energy that might be explored.

Additional Direct Service Industry Interruptibility

One method for making additional in-region use of nonfirm energy is by increasing the amount of nonfirm load served by the regional utilities. The Council examined this issue by looking at converting additional firm direct service industry load to nonfirm service. This allows Bonneville to reduce its firm resource acquisitions by the amount of the converted load. These savings are offset by lost nonfirm revenues from outside the region, as the nonfirm is used instead to serve the new regional nonfirm load, and by an imputed curtailment cost when that load cannot be met.

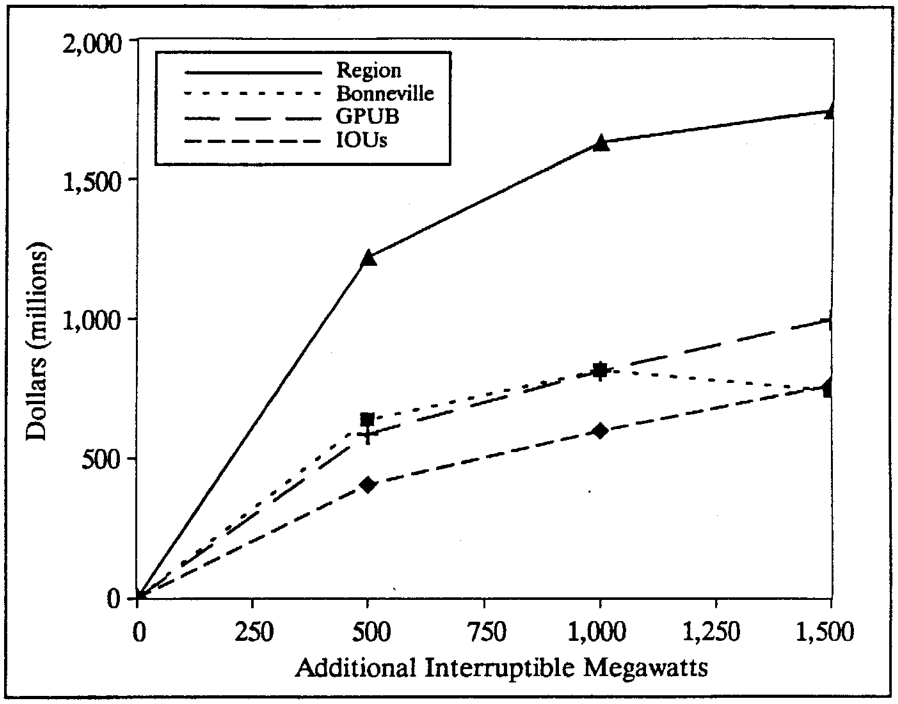
Figure 8-30 summarizes the results of the study. Conversion of additional 500-megawatt increments of firm load was examined, up to 1,500 additional megawatts. The figure shows the net reduction in system costs due to the conversions for the total region and for the three groups of utilities separately identified in the Council's decision model. These three groups are Bonneville, including the non-generating public utilities and the direct service industries, the generating public utilities and the investor-owned utilities.

The study was set up to reach the full conversion level in 2001, the date the current contracts expire, with a uniform ramp-up to that level over the preceding five years. The ramp simulates a planned conversion and eliminates most of the overbuilding of resources due to lead times longer than the duration of the ramp. However, loads were converted at the same dates in all load cases, so in the lower load cases, firm surpluses were created or extended to where they would not have been if the conversion were negotiated to be scheduled as a resource.

Because of these provisions for scheduling the conversion from firm loads to nonfirm loads, these studies are not directly comparable to the previously described Council studies examining the cost-effectiveness of gas combustion turbines and combined-cycle plants. The earlier studies compared coal plants to gas generation, when they were needed to meet load. These studies compare using available nonfirm to meet loads with scheduling whatever resource is next in the priority list to meet additional loads. In these studies, sometimes the comparison is with coal plants, sometimes with cheaper, higher-priority resources and sometimes with no acquisition alternative at all, for example, in the low load cases, where additional resources are not needed.

DSI Interruptible Loads

Figure 8-30
Value of Increased Direct Service Industries Interruptible Load



The study examines only the value to the non-direct service industry customers of the region. The costs to these customers are represented by two quantities. The first is lost extra-regional sales, as the nonfirm is diverted to interruptible load service rather than extra-regional sales. In those water conditions in which insufficient nonfirm energy is available, the interruptible load is curtailed and a cost of 2.5 cents per kilowatt-hour in real terms is imputed as a cost to the remaining customers. This can be taken as a surrogate for the lost Bonneville revenue due to curtailment of the load. No cost was directly ascribed to the direct service industry customers either for replacement power or for lost production or wages.

The study results, summarized in Figure 8-30 show that the regional benefits increase up to about 1,000 megawatts of additional nonfirm load, and then flatten out, with a relatively small increase in benefits between 1,000 and 1,500 megawatts. This occurs because the benefits to Bonneville decline above about 1,000 megawatts. Since the study was only done in 500-megawatt increments, the actual peak may be somewhat higher or lower than 1,000 megawatts. The extra 1,000 megawatts of interruptible load correspond to about 25 to 30 percent more than one additional quartile of interruptible load. While this study focused on direct service industry loads, similar results would likely be seen if other firm loads were converted to nonfirm loads under similar service provisions.

Extra-regional Exchanges

Extra-regional exchanges represent another means by which the Northwest could make better use of its nonfirm energy. The most valuable type of exchange is one that the Council has encouraged in the past--capacity-energy exchanges--in which summer capacity is sold to the Southwest or California in exchange for energy to be delivered to the Northwest in the event of low water conditions. Capacity-energy exchanges with California or Desert Southwest utilities offer the opportunity to back up Northwest nonfirm hydro energy while avoiding concerns about limited pipeline transmission capacity in the Northwest.

This is because the gas market in California is almost six times larger than that in the Northwest, and California already has a large amount of gas generation in place. Moreover, there is off-peak coal energy available from the Southwest that would be even cheaper than California gas backup. This type of exchange is particularly valuable because it brings net energy into the region; simple summer and winter capacity exchanges leave the region's energy balance the same after the transaction as before.

Additional unshapeable fishery flows might be required by the Council's fish and wildlife program or the Endangered Species Act. The Council also encourages storage or exchange transactions that would allow the Northwest to extract the highest economic value from increases in nonfirm energy availability resulting from these flow requirements. Return of storage or exchange energy should be timed so that it does not interfere with whatever flow requirements are in effect at the time by reducing the need for Northwest hydro generation.

Methodology

The cost-effectiveness of individual resources can only be determined by considering how they integrate with the entire system. Cost-effectiveness is a relative quantity--that is, a resource is cost-effective if it produces power at an "incremental system cost" less than another resource. As was done for previous power plans, the cost-effectiveness of gas-fired generation was determined by comparison to the region's assumed marginal resource, a coal plant.

The System Analysis Model (SAM), used for the analysis, simulates the operation of the region's power system to meet loads. For this analysis, a comparison was made between two systems, one that met load growth with coal plants and the other, which met load growth with combined-cycle combustion turbines. Total system costs were compared to compute net benefits. The comparison included the benefits of current uses of nonfirm power. This analysis was done for different levels of installed new resource energy in order to determine the most cost-effective amount of combustion turbine energy to include in the resource mix.

Only existing thermal resources were used, along with a set of loads that yielded about an 800-megawatt surplus in the first year, decreasing to a balanced condition by 1994 through the end of the study period. To perform the desired analysis, an arbitrary increase to the loads was made in September 1999. This incremental load increase was met by the installation of an equal amount of coal energy in one case and combustion turbine energy in a second case. Comparisons were based on the present value of net revenue requirements for both cases. This type of comparison was made for load increases up to 3,000 average megawatts in increments of 500 megawatts. Resources used to meet these load increases were constructed to exactly match the load growth.

Each case included only existing regional thermal resources. Conservation and renewable resources were assumed to increase over time to a level of about 1,900 average megawatts by the year 2009. That corresponds to the level of development for a medium growth scenario as described in the 1989 supplement. Existing resources include about 400 average megawatts of combustion turbine energy. New thermal resources were assumed to be built by investor-owned utilities. No real escalation was assumed for capital cost.

Nonfirm energy from BC Hydro was assumed to be available for displacement of Northwest resources. The model also simulates the California nonfirm market. Firm exports and imports are taken into account as are the limits of the interties between regions.

In this analysis, an obvious end-effect problem exists due to the different assumed lives of the two resources being compared. Combustion turbines retire 10 years before coal plants. The net revenue requirements for the coal studies, therefore, would contain an additional 10 years of operating costs. To compensate for the shorter combustion turbine life, it was assumed that when the turbines expire, new combustion turbines would replace them. This required that the simulation continue beyond the study horizon period, normally 20 years.

Unfortunately, SAM can only simulate to a maximum of 20 years. To perform the simulation beyond the 20-year study horizon, the AFTERSAM model was used. Unlike SAM, this model performs a deterministic simulation of the Northwest's power system. It does provide, however, a good approximation to the simulation in SAM. AFTERSAM computes capital costs, production costs and curtailment costs as well as secondary revenues for each post-study horizon year. It models the California nonfirm market, but, as yet, does not include a model of the BC Hydro nonfirm availability.

Using this end-effect model, all operating year costs were folded into one present-value net-revenue requirement that represented a study horizon of 50 years.

Fuel Cost Assumptions

Natural Gas

Natural gas may be purchased under either firm or interruptible delivery contracts, or purchased on the spot market. Delivery of firm ("contract") gas is guaranteed, but at a premium price compared to interruptible gas. The price differential is attributable to the cost of constructing, operating and maintaining the natural gas transmission and distribution system, and the cost of providing peak-period service.

Under equilibrium conditions, the price of natural gas is set through the interaction of interruptible natural gas and residual fuel oil in the industrial boiler fuel market. The two fuels are generally interchangeable, and industrial users can purchase the least costly option. Therefore, the price of residual fuel oil caps the price of interruptible natural gas. Under conditions like the current natural gas surplus, the price of interruptible gas may drop well below that of residual fuel oil. Firm gas prices are based on the same commodity charge as interruptible gas, but incorporate the additional fixed costs associated with guaranteed delivery. Firm gas prices therefore generally follow interruptible gas price movements, but at a higher level.

Natural gas prices are shown in Table 8-30 and fuel oil prices in Table 8-31. Interruptible gas prices follow residual fuel oil prices through the study period, with the exception of the early years, during which the current gas surplus is worked off. Prices begin at $2.72 per million Btu in 1988, and decline through 1990 because of the gas surplus. Escalation is rapid in the early 1990s as the surplus is exhausted. As equilibrium with oil is re-established in the mid-1990s, the rate of natural gas escalation declines to a rate close to that of fuel oil. The overall rate of escalation of natural gas over the planning period is 2.8 percent, compared to 1.8 percent in the 1986 plan.

Firm gas prices follow interruptible prices, but at a higher level, reflecting the additional costs of firm service. Prices begin at $3.61 per million Btu in 1988, with an overall rate of escalation over the 20-year planning period of 1.9 percent.

The Council has chosen the average of the firm and interruptible natural gas price forecasts to be conservative with regard to the cost of operating the turbines and because the fuel could actually be supplied under any one of several scenarios mixing firm and interruptible gas, as described earlier in this chapter. This hybrid gas price series used for plants operated to back up nonfirm hydropower begins at $3.16 in 1988 and escalates at an average rate of 2.3 percent over the 20-year planning period.

If the nationwide movement to increased use of natural gas for thermal and electrical applications continues, natural gas prices may increase more rapidly than forecast. Because coal gasification technology is now commercially available, the cost of coal-derived synthetic gas may set a ceiling on natural gas prices for utility applications.

Table 8-30
Natural Gas Prices[a]

Heat Value		1,021 Btu/SCF (HHV)	1,021 Btu/SCF (HHV)	1,021 Btu/SCF (HHV)
Source		Not Specified	Not Specified	Not Specified
Delivery		PNW Site	PNW Site	PNW Site
Transport		Pipeline	Pipeline	Pipeline
Purchase		Interruptible	Firm Contract	Hybrid Contract (50/50)
Fixed Delivery Cost (1988$/kW)		$2.70	$2.70	$2.70
Variable Cost (1988$/MMBtu)	1988	$2.72	$3.61	$3.16
	1989	$2.42	$3.27	$2.85
	1990	$2.15	$3.02	$2.58
	1991	$2.34	$3.19	$2.77
	1992	$2.56	$3.35	$2.95
	1993	$2.79	$3.53	$3.16
	1994	$3.05	$3.76	$3.40
	1995	$3.33	$3.96	$3.64
	1996	$3.45	$4.08	$3.76
	1997	$3.57	$4.22	$3.89
	1998	$3.70	$4.33	$4.02
	1999	$3.83	$4.48	$4.16
	2000	$3.98	$4.60	$4.29
	2001	$4.06	$4.69	$4.38
	2002	$4.16	$4.79	$4.48
	2003	$4.25	$4.90	$4.57
	2004	$4.35	$5.00	$4.67
	2005	$4.46	$5.08	$4.77
	2006	$4.51	$5.16	$4.84
	2007	$4.58	$5.20	$4.89
Average Escalation (1988-2007)		2.8%	1.9%	2.3%

[a] 1,021 Btu/SCF (Higher Heat Value).

Distillate Fuel Oil

Distillate (No. 2) fuel oil is used to fire boilers, simple-cycle and combined-cycle combustion turbines, and diesel generators. It may substitute for natural gas in these applications, but it generally commands a premium price relative to natural gas, under equilibrium price conditions, because it can be transported and stored more easily. For this reason, in the Pacific Northwest, distillate fuel oil use is limited to back-up fuel for combustion turbines, unless natural gas is not available at the plant site. It is expected that use of distillate as a utility fuel will continue to be limited to those uses.

If used as a back-up fuel, distillate purchases by utilities would be relatively small scale, and prices should be similar to those for other industrial sectors. Therefore, the proposed utility distillate fuel price series is based on the industrial oil price series prepared for the load growth forecasts. The distillate series is obtained by adding an estimated distillate premium to the crude price series underlying the regional average industrial oil price forecasts.

Distillate prices are forecast to begin at $3.66 per million Btu in 1988. This is much lower than the $5.70 per million Btu (1985 dollars) used in the 1986 plan, due to the drop in crude oil prices in 1986. Following a slight decline through 1990, as shown in Table 8-31, distillate prices are forecast to escalate through the balance of the planning period. The average rate of escalation over the 20-year period is 2.5 percent, compared to 1.9 percent used in the 1986 plan.

Residual Fuel Oil

Residual (No. 6) fuel oil is used to fire boilers in the utility sector. Because it can substitute for natural gas in boiler applications, it is the principal link between natural gas prices and fuel oil prices. There are few natural gas or oil-fired utility boilers in the Pacific Northwest.

Because of limited future use, utility residual fuel oil prices are likely to be similar to those for other industrial sectors. The proposed series of residual fuel prices is therefore the same as the regional average industrial residual fuel price series. Prices begin at $2.72 per million Btu, and hold relatively steady through 1990, shown in Table 8-31. Beginning in 1991, real prices begin to escalate through the end of the study period. The average rate of escalation through the 20-year study period is 2.8 percent. This escalation rate is greater than that of distillate fuel oil, because it is anticipated that improved refining technology and increasing demand for lighter petroleum products will, over time, reduce the availability of heavy products such as residual oil. Also, the near-term price of residual oil is lower than that of distillate, so an equivalent price increase results in a greater rate of escalation.

Reference Power Plants

Plant operating data and assumptions were based on the Council's reference simple-cycle and combined-cycle power plants. Table 8-32 below gives a summary of the assumptions used for this analysis; more detail regarding these power plants is provided in Appendix 8-A.

Note that the coal cost assumptions for this study are significantly lower than the costs used in other, more recent, studies for the Draft 1991 Power Plan. More recent estimates of coal capital costs, for example, range from $1,710 to $2,026 per kilowatt, compared to the $1,210 per kilowatt used in this study. Since the combustion turbine costs and performance assumptions have not changed significantly since then, the effect of updating the coal estimates would be to make a larger commitment to combustion turbines cost-effective. However, this would not change the Council's portfolio or Action Plan because the limitations on the resource size in this Draft 1991 Power Plan were set based on a policy judgment on the current uncertainty about gas availability and potential price escalation.

Hydrofirming Resource Planning Assumptions

The base-case planning assumptions used for this resource in subsequent resource portfolio analyses are summarized in Table 8-33.

Table 8-31
Fuel Oil Prices

		Residual Fuel Oil	Distillate Fuel Oil
Fuel Type		Fuel Oil No. 6	Fuel Oil No. 2
Heat Value		994 Btu/lb. (HHV)[a]	19,161 Btu/lb (HHV)[a]
Source		Not Specified	Not Specified
Delivery		PNW Site	PNW Site
Transport		Rail or Barge	Rail or Barge
Purchase		Spot	Spot
Fixed Delivery Cost (1988$/kW)		$0.00	$0.00
Variable Cost (1988$/MMBtu)	1988	$2.73	$3.66
	1989	$2.79	$3.67
	1990	$2.69	$3.68
	1991	$2.81	$3.82
	1992	$2.94	$3.97
	1993	$3.07	$4.12
	1994	$3.20	$4.27
	1995	$3.34	$4.44
	1996	$3.46	$4.58
	1997	$3.59	$4.72
	1998	$3.71	$4.87
	1999	$3.86	$5.03
	2000	$3.99	$5.18
	2001	$4.09	$5.29
	2002	$4.17	$5.40
	2003	$4.27	$5.51
	2004	$4.37	$5.63
	2005	$4.48	$5.74
	2006	$4.53	$5.82
	2007	$4.60	$5.88
Average Escalation (1988-2007)		2.8%	2.5%

[a] HHV - High Heating Value.

Table 8-32
Cost and Performance Characteristics of Study Power Plants[a] *(1988 Dollars)*

	603 MW Pulverized Coal-Fired Steam-Electric Plant	139 MW Simple-Cycle Combustion Turbine	420 MW Combined-Cycle Combustion Turbine
Plant Configuration	Two 603-MW Units	Two 139-MW Units	One 420-MW Unit[b]
Rated Capacity (MW/unit)	603	278	420
Peak Capacity (MW/unit)	633	152	452
Equivalent Annual Availability (%)	75%	85%	83%
Heat Rate (Btu/kWh)	10,856	11,480	7,620
Siting and Licensing Cost ($/kW)	$23	$5	$6
Siting and Licensing Hold Cost ($/kW/yr.)	$0.80	$0.50	$0.40
Construction Cost ($/kW)[c]	$1,245	$544	$629
Fixed O&M Cost ($/kW/yr.)[d]	$20.50	$2.00	$5.40
Variable O&M Cost (mills/kWh)	1.9	0.1	0.3
Siting and Licensing Lead Time (months)	48	24	36
Construction Lead Time (months)	72[e]	24	36
Service Life (years)	40	30	30

a See the *1989 Supplement to the 1986 Power Plan* for additional information concerning these technologies and sources of cost and performance information.
b Two 139 megawatt GE MS7001 combustion turbines, one heat recovery steam generator and one 141 megawatt steam turbine-generator.
c "Overnight" costs (excludes interest during construction).
d Includes post-operational capital replacements.
e To first unit of two-unit project.

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Table 8-33
Hydrofirming Resource Planning Assumptions (1988 Dollars)

	Combined-Cycle 1	Combined-Cycle 2
Total Capacity (MW)	1,260	1,680
Total Firm Energy (MWa)	1,050	1,400
Unit Capacity (MW)	420	420
Seasonality	Winter Peak	Winter Peak
Dispatchability	Dispatchable	Dispatchable
Siting and Licensing Lead Time (months)	24	24
Probability of S&L Success (%)	75%	75%
Siting and Licensing Shelf Life (years)	5	5
Probability of Hold Success (%)	90%	90%
Construction Lead Time (months)	36	36
Construction Cash Flow (%/year)	8/41/51	8/41/51
Siting and Licensing Cost ($/kW)	$6	$6
Siting and Licensing Hold Cost ($/kW/year)	$0.40	$0.40
Construction Cost ($/kW)	$629	$629
Fixed Fuel Cost ($/kW/year)	$0.00	$0.00
Variable Fuel Cost (mills/kWh)	24.1	24.1
Fixed OM&R Cost ($/kW/year)	$5.40	$5.40
Variable O&M Cost (mills/kWh)	0.3	0.3
Earliest Service	1995	2000
Peak Development Rate (units/year)	1	1
Operating Life (years)	30	30
Real Escalation Rates (%/year)		
Capital Costs	0%	0%
Fuel Costs	2.3% (average)	2.3% (average)
O&M Costs	0%	0%

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Nuclear

Nuclear power produces energy by the controlled fissioning (splitting) of isotopes of heavy elements such as uranium, thorium and plutonium. At its inception, commercial nuclear fission promised to be an economical, abundant and non-polluting source of electric power. But the commercial history of this technology has been troubled. Construction cost overruns, failure of many plants to perform reliably, catastrophic plant failures at Three Mile Island and Chernobyl, seemingly intractable problems with establishing high-level waste disposal capability and escalating operation and maintenance costs have diminished the promise of this technology.

These factors have led to intense controversy regarding commercial nuclear power. No new plants have been ordered in the United States since 1978, and many orders placed before then were canceled. Nonetheless, as of mid-1989, 110 operable reactors, amounting to 97,182 megawatts of capacity were licensed for commercial operation in the United States. These plants produce nearly 20 percent of the electricity consumed in the United States.

Two commercial nuclear power plants are in service in the Pacific Northwest. The Trojan Nuclear Plant, located on the Columbia River near Rainier, Oregon, is a 1,152-megawatt capacity pressurized water reactor plant that has been in service since 1976. This plant produces 726 average megawatts of energy. Portland General Electric operates Trojan and owns 67.5 percent of the plant. Eugene Water and Electric Board owns 30 percent, which is assigned to the Bonneville Power Administration, and Pacific Power and Light Company owns 2.5 percent. The output of the Eugene share is sold to Bonneville through a net-billing agreement.

The Washington Public Power Supply System's (WPPSS) nuclear project 2 (WNP-2), located on the Hanford Reservation in Eastern Washington, is a 1,095-megawatt capacity boiling water reactor plant that has been in service since 1984. This plant produces 711 average megawatts of energy. WNP-2 is owned and operated by the Supply System. The output (project capability) of WNP-2 has been assigned to 94 consumer-owned utilities, which have re-assigned their shares to Bonneville through net-billing agreements.

Eight additional commercial nuclear plants were at one time planned in the Northwest. Six were terminated when it became evident that their output would not be needed in the foreseeable future. Construction of two others, WNP-1 and WNP-3, was suspended when these plants were about 65 and 75 percent complete, respectively. These two plants have been maintained in a technical condition that would allow them to be completed if and when they are needed.

The first part of this section deals with issues related to the WNP-1 and WNP-3 plants. Status, preservation, completion and operational issues and planning assumptions for these plants are discussed. The second part of this section deals with new technology for nuclear power. The final part discusses environmental concerns, such as air and water impacts and radioactive waste.

Washington Nuclear Projects 1 and 3 (WNP-1 and WNP-3)

Status of WNP-1

WNP-1 is a 1,250-megawatt capacity commercial nuclear power plant located on the Hanford Reservation in Eastern Washington. It is anticipated that the plant will produce about 810 average megawatts of energy. The nuclear steam supply system is of Babcock and Wilcox design. This plant was a twin to the now-terminated WNP-4 plant. The plant is owned by the Washington Public Power Supply System. The project capability has been assigned to 115 consumer-owned utility customers of Bonneville, which have re-assigned their shares to Bonneville through net-billing agreements. Construction and operation, if completed will be the responsibility of the Washington Public Power Supply System.

WNP-1 was scheduled for commercial operation in June 1986. In May 1982, the Supply System and Bonneville suspended construction. This decision was based on revised load forecasts showing lower electrical load growth than previously anticipated, and upon perceived difficulties in marketing bonds for continued construction financing. The plant is estimated to be approximately 65 percent complete, based on construction man-hours required for completion.

Status of WNP-3

WNP-3 is a 1,240-megawatt capacity commercial nuclear power plant located near Satsop in Grays Harbor County, Washington. It is anticipated that this plant will produce about 870 average megawatts of energy. The nuclear steam supply system is of Combustion Engineering design. The power plant was a twin to the now-terminated WNP-5 plant. Seventy percent of the plant is owned by the Supply System. The project capability of the Supply System's ownership share has been assigned to 103 consumer-owned utilities, which have re-assigned their shares to Bonneville through net-billing agreements. The remaining 30 percent of the plant is owned by four investor-owned utilities. Under the terms of a settlement negotiated in response to a breach-of-contract suit filed by these investor-owned utilities, Bonneville may acquire, at the cost to complete construction only, the capability of the investor-owned utility share of WNP-3 in accordance with the provisions of Section 6(c) of the Northwest Power Act.

WNP-3 was scheduled for commercial operation in December 1986. Construction was slowed in February 1983. The slowdown was prompted by revised load growth forecasts showing lower load growth than previously estimated. In July 1983, because of the inability to continue marketing construction bonds, construction was suspended for three years or until financing was found to be available. Construction is estimated to be approximately 75 percent complete, based on construction man-hours required for completion.

Preservation Issues

The plants and associated engineering, quality control and licensing documents have been preserved since suspension of construction, so that either plant can be completed and operated if needed in the future. A long-term minimum-level preservation program is in effect for both plants. Current preservation program costs are about $5 million per year for WNP-1. WNP-3 preservation costs are about $5.5 million per year, exclusive of property taxes on the investor-owned utility portion of the plant.

Under the WNP-3 settlement, Bonneville is obligated to pay the property taxes that are due to Thurston County on the 30 percent share of WNP-3 held by investor-owned utilities. Beginning with the 1988 assessment, the property taxes were increased substantially, to an annual sum of about $5 million. At Bonneville's direction, the four investor-owned utilities are challenging the county's assessment, and the matter is now before the Thurston County Superior Court.

Important issues affecting the continued ability to preserve the plants for future use include the ability to preserve the plants physically, the ability to continue to fund preservation and the ability to maintain permits and licenses required for future construction and operation.

Physical Preservation

Prolonged suspension of construction could result in physical deterioration of plant structures and equipment. Such deterioration would increase construction costs to complete the plants because of the additional cost of rehabilitation or replacement. In assessing the cost-effectiveness of WNP-1 and WNP-3 in the 1986 Power Plan, the Council concluded that the plants could likely be maintained and that completion of the plants could be deferred until the end of the planning period. This conclusion was based upon the satisfactory results of the preservation programs then in place. Although those preservation programs were not intended to support long-term preservation, corrosion rates, for example, were well within acceptable limits for long-term preservation.

Subsequent monitoring of the plants' physical condition indicates little evidence of deterioration, leading the Council to conclude that the plants can apparently be physically preserved for an indefinite period. Some slow deterioration of equipment or structures will undoubtedly occur and this, combined with technical obsolescence of specific items of equipment will likely slowly increase costs-to-complete. This cost escalation appears to be adequately covered by the capital cost escalator assumed for these plants in this plan. Replacement of technically obsolete equipment, such as computer control systems, with state-of-the-art equipment should lead to improved plant performance.

Preservation Financing

Given that the ability to continue long-term physical preservation of the plants has been demonstrated, the ability to continue to preserve the plants becomes largely a financial and political question. Annual preservation costs have been reduced to $5 million to $6 million per plant. Income from the unexpended WNP-

1 construction fund covers the cost of that plant's preservation. Preservation funds for Plant 3 come from Bonneville rates. Lower preservation costs than originally expected (estimated annual preservation costs were $12 million per plant when the 1986 plan was prepared) appear to have reduced political pressure to terminate the plants and have helped Bonneville to continue to fund preservation.

Though continued preservation appears less contentious than it did in 1986, conflicting factors render difficult any assessment of the ability and desirability of preserving the plants through 2000. On one hand, the ability to preserve the plants physically has been demonstrated and regional and Bonneville surpluses have declined. Concerns regarding global warming and its effects on the future viability of fossil-generated power are growing. These factors encourage continued preservation. On the other hand, there is continued opposition to nuclear power among many members of the public, little load growth among many Bonneville customers and no interest on the part of the investor-owned utilities to consider investments in large, new generating resources. Also, the operating record of the region's completed nuclear plants is perceived by many to be mediocre. These factors weigh against continued interest in preserving WNP-1 and WNP-3.

Permits and Licenses

Completion of construction and operation of WNP-1 and WNP-3 would require maintenance of numerous permits and licenses. The principal permits and licenses include the Site Certification Agreements, National Pollutant Discharge Elimination System Permits, U.S. Army Corps of Engineers' waterways permits and the Nuclear Regulatory Commission Construction Permits and Operating Licenses. The plants also require riverbed leases issued by the Washington State Department of Natural Resources. All are in effect except for the Operating Licenses.

Numerous state and local permits and licenses are subsumed within the Site Certification Agreement, which is the certification that results from the State of Washington "one-stop" licensing process. Site certification agreements are issued by the Washington State Energy Facility Site Evaluation Council to authorize the construction and operation of large power generating facilities. The site certification agreements remain in effect for WNP-1 and WNP-3, with conditions permitting operation as originally planned.

The National Pollutant Discharge Elimination System (NPDES) permit governs the discharge of wastewaters from the plant. This permit is issued by the State of Washington, and must be renewed every five years. When the 1986 plan was being prepared, a concern was raised that the NPDES permits had characteristics of water rights and that in the case of WNP-3, competing beneficial uses of water could preempt the rights conferred by this permit. In 1986, the Supply System applied for, and was granted, normal five-year extensions to both the NPDES permits for both WNP-1 and WNP-3. It appears that the NPDES permits can continue to be renewed.

The Supply System holds riverbed leases from the Washington Department of Natural Resources for water withdrawal and discharge structures for WNP-1 and WNP-3. One lease, expiring in 2005, is held for WNP-1. Four riverbed leases are held for WNP-3. These expire in July and August 2000 and in May 2005. It appears that these leases can be renewed in accordance with the right-of-renewal provisions in the leases.

The Supply System has obtained permits from the Corps of Engineers for construction and maintenance of cooling water intake and discharge structures. These structures are complete, and it is not expected that additional permits from the Corps of Engineers will be required.

The U.S. Nuclear Regulatory Commission issues a construction permit for the construction of commercial nuclear power plants, and an operating license for their operation. The construction permit for WNP-3 was issued in April 1978. The construction permit for WNP-1 was issued in December 1975 and was extended to June 1991. More recently, the Nuclear Regulatory Commission has established a policy for extended construction delays. The current preservation programs for WNP-1 and WNP-3 comply with this policy. Because of the extended construction delay for WNP-3, the Supply System, in 1988, was granted an extension of the WNP-3 construction permit to July 1999. Based on the recent extension of the construction permit for WNP-3 to 1999, a similar extension to the construction permit for WNP-1 is expected prior to its expiration in 1991.

In July and August 1982, the operating license applications for WNP-1 and WNP-3, respectively, were accepted for docketing by the Nuclear Regulatory Commission. Operating licenses are issued prior to commercial operation, for a term of 40 years. Unlike earlier practice, when the term for the operating license ran from receipt of the construction permit, the term, which is still 40 years, now commences with commercial operation.

There is reason to believe that both WNP-1 and WNP-3 could receive their operating licenses under current licensing requirements, although this is not assured. When preparing the most recent cost-to-complete estimates in 1984, the Supply System reviewed pending Nuclear Regulatory Committee regulatory actions that might require design changes prior to issuance of the operating licenses. The costs of these design changes were incorporated into the cost estimates. More recently, an assessment of possible additional seismic requirements at WNP-3 has been completed, with the conclusion by the Supply System that the current design of WNP-3 is seismically adequate. In May 1989, the Supply System again reviewed the costs-to-complete, identifying changes in regulatory requirements (including those other than NRC regulatory actions) that might affect costs. These requirements are believed to increase cost-to-complete by about 10 percent. Because the designs of these plants are essentially the state-of-the-art for nuclear plants, even though designed in the mid-1970s, it is likely that the most significant uncertainty associated with receiving operating licenses is not whether the licenses would be granted, but rather what the cost may be for implementing currently unplanned design changes required for that license. These cost increases are captured in the capital cost escalation rate used in this plan. Capital cost escalation rates are presented later in this section.

Completion Issues

WNP-1 and WNP-3 have no value as regional power sources unless the plants can be completed and operated. Analysis of the issues related to completing the plants suggests that resumption of construction requires resolution of a number of major issues. In view of the favorable experience with improved construction management procedures implemented prior to suspension of WNP-3 construction, if resumed, construction may go smoothly.

Important legal hurdles affecting the feasibility and time required to resume and complete construction are discussed below. Following this discussion, several additional issues affecting construction are addressed.

There are two myths surrounding the possible restart of WNP-1 and WNP-3. The first is that the legal hurdles are trivial, and construction can be resumed anytime, just as soon as the contractors can be remobilized. While this might have been true for the first 12 to 15 months after construction was suspended, it is no longer true. Restart of construction on WNP-1 and WNP-3 now will require the resolution of several tough, and probably somewhat lengthy, legal issues.

The second myth is that the legal hurdles for WNP-1 and WNP-3 are much more difficult than those for other resources. This is not so. The level of legal difficulty involved in getting WNP-1 and WNP-3 up to the point that construction can resume is probably less than that required to site a new, large coal plant. While there are some unique issues, a major legal hurdle for WNP-1 and WNP-3 is one common to all large projects--an environmental impact statement.

Failure to resolve these major issues could prevent construction from resuming on WNP-1 and WNP-3. But none of the issues, viewed individually, appears to be insurmountable, although they may prove very difficult to resolve.

Environmental Impact Statement (EIS)

Whenever a federal agency is preparing to take a major action significantly affecting the environment, it is required to prepare a statement of the environmental consequences and alternatives to the proposed action. A decision to resume construction on either WNP-1 or WNP-3 after a shutdown of a number of years is likely to be viewed as a major action. A similar question was confronted by the U.S. Department of Energy (the Department) in restarting a completed Savannah River reactor after a "permanent" shutdown. The Department concluded that such a restart was a major action, and they prepared a full EIS.

Either proceeding without an EIS, or with only a short environmental assessment rather than a full EIS, is not likely to be a practical choice for Bonneville. A decision to proceed without an EIS would be immediately challenged in court, and there is a high probability that a court would ultimately require an EIS. Thus, proceeding without an EIS would guarantee several years of litigation and could delay construction even longer while the case is considered, all with little chance of avoiding the EIS requirement.

There already have been several environmental impact statements prepared for these plants. Prior to initial construction, in the early 1970s, each plant had a state EIS and a Nuclear Regulatory Commission construction EIS. In addition, the Commission issued its draft final environmental statement for WNP-3 in 1985. However, there has been no EIS prepared by Bonneville.

Probably much of the information required for a Bonneville EIS is already in the earlier environmental impact statements and Bonneville can incorporate such information in its own EIS. However, some additional analysis will doubtless be required. A very preliminary estimate is that preparing the draft EIS, taking public comment on it, and preparation of a final EIS will probably require at least 18 months and could take two years or longer.

Litigation on Adequacy of EIS

Once the environmental impact statement is completed, there is likely to be litigation about its adequacy. If the record of decision in the EIS calls for a restart of construction, a court is likely to allow construction to proceed during litigation on the EIS, since the environmental harm resulting from continued construction at an existing construction site is relatively small. Normally, litigants against construction would seek an injunction prohibiting construction from proceeding until the EIS litigation is resolved. Such injunctions are granted only in a minority of the cases.

As long as the EIS is in court, there is some additional risk to the purchasers of bonds issued to resume construction of court-ordered project delays, additional expenses or conditions that make it too expensive to complete the project. However, since the bonds are backed by Bonneville revenues, the ultimate risk to the bond buyers is small. Thus, the EIS litigation is not likely to delay financing or construction of the projects, absent an injunction.

The probable time required to resolve such litigation is around two and one-half years after the EIS is completed. This assumes a U.S. Court of Appeals for the 9th Circuit decision in about one and one-half years and that the Supreme Court declines review about a year after the 9th Circuit decision. The Supreme Court accepts only about 3 percent of the cases filed with it and rarely accepts an EIS appeal. In the event that the 9th Circuit or the Supreme Court determines that the original EIS was inadequate, correcting the EIS and resolving the follow-on litigation could add another two to three years.

Participant Opposition

The Snohomish County Public Utility District wrote to the Supply System in June 1989, expressing its opposition to continued preservation or construction of WNP-1 and WNP-3. Snohomish explained that the projects were terminated by the Supply System when construction was delayed on the projects. Snohomish has stated that it will oppose any further construction of these projects. Snohomish is a major participant in both projects, with a 13-percent share of WNP-1 and a 19-percent share of WNP-3, all of which has been assigned to Bonneville under net-billing agreements.

Subsequently, Mason County Public Utility District No. 3 and Orcas Public Utility District, minor participants in the projects, also expressed opposition to the continuation of the projects. While no other major participants have joined Snohomish, it is possible that other participants also may be reluctant to resume construction.

The net-billing agreements allow a participant to sell its project shares to others in some circumstances, but nothing in the agreements deals specifically with this situation, in which a participant refuses to proceed with the projects and is not willing to surrender its shares. However, the net-billing agreements do establish a participants' committee, which has the authority to disapprove budgets, certain contracts and certain other proposals of the Supply System if those proposals are not in accordance with prudent utility practice as defined in the agreements.

The experts disagree about how much impact the Snohomish opposition would have. Bond counsel and other lawyers involved with the recent sales of bonds to refund earlier high-interest rate WNP-1, WNP-2 and WNP-3 bonds issued opinions stating that the projects have not been terminated, and the Snohomish letter did not prevent successful sales of refunding bonds. It is not clear, however, whether these opinions will be adequate to permit new construction bonds to be sold with similar success.

Snohomish has said that it is prepared to pursue its opposition to restarting construction in court, if necessary.

Generally, courts won't allow one participant in a multiparty venture to lock up the whole venture. It is, therefore, unlikely that a small minority of participants would be able to prevent other participants from eventually proceeding with the project. However, litigation by Snohomish could delay the project, or perhaps make it difficult to obtain construction financing until the litigation is resolved.

Thus, two to three years of litigation are likely, with an outcome that the projects will be allowed to proceed. During the litigation, there is some chance that the litigation itself will keep the Supply System from obtaining financing or proceeding with construction.

Initiative 394

Initiative Measure Numbers 394 (RCW 80.52.010 et seq.), adopted by the voters of Washington in November 1981, requires joint operating agencies, including the Supply System, to prepare a cost-effectiveness study and seek voter approval before bonds can be issued to finance a major energy project.

The bond fund trustees challenged the initiative in the 9th Circuit. In early 1983, the 9th Circuit held that the voter approval provisions of the initiative could not be applied to WNP-1 and WNP-3, because they impaired the obligation of the contract between the Supply System and its bondholders. See Continental Illinois National Bank v. State of Washington, 696 F.2d 692 (1983). Rather than appeal the 9th Circuit decision to the U.S. Supreme Court, the State of Washington entered into a settlement with the Supply System.

The settlement requires the Supply System to prepare a cost-effectiveness study in the manner contemplated by Initiative 394, but does not require the Supply System to seek voter approval before selling bonds. The settlement recognized that a cost-effectiveness study had already been completed for WNP-3, and, therefore, it allows the Supply System to sell bonds to finance that project, providing the bond-financed share does not exceed $960 million. The limit for WNP-3 comes from a 1983 estimate of the cost to complete Bonneville's 70-percent share of the project. If Bonneville exercises its option to acquire the remaining 30 percent of the project output from the investor-owned utilities, and the completion of the project is financed through bonds, then a further cost-effectiveness study will be required for WNP-3 as well.

The study must be prepared by an independent consultant approved by the State Finance Committee. The consultant must look at the Supply System's estimates of the anticipated costs of construction and the types and amounts of bonds to be used to finance it, and then project the impact on rates. The standards for determining cost-effectiveness are copied almost verbatim from the Northwest Power Act and are essentially the same as those used by the Council.

Upon completion, the draft study is filed with the Washington secretary of state and made available for public comment for 30 days. Following the public comment, a final draft, which must respond to any comments submitted by the Washington State Energy Office, is to be filed with the secretary of state.

It is important to recognize that the cost-effectiveness study is a pre-condition to bond sales by the Supply System, not to construction of the projects. If the remaining construction on a project is financed by some means other than bonds, perhaps directly from Bonneville's revenues, then no cost-effectiveness study is required.

A rough estimate is that the cost-effectiveness study will take between one and 1-1/2 years to complete. Allowing for public comment and possible legislative consideration, the process will probably take about two years overall.

Amendments to State Contracting Laws

Washington law requires joint operating agencies such as the Supply System to use competitive bidding to purchase materials or obtain construction contracts. An exception allowing for negotiated contracts is provided for operating nuclear plants, but the exception does not apply to plants still under construction.

The Supply System's experience in finishing and operating WNP-2 strongly suggests that a negotiated contract will be the best and least expensive way to complete the plants. An amendment to Washington state law (RCW 43.52.565) will be required to allow the Supply System to use such a contract.

Failure to obtain such an amendment would not prevent completion of the plants. Although an amendment would streamline the contracting process, the present law has some flexibility. The Supply System may be able to work within the existing law to create an agreement with most of the advantages of a negotiated contract.

An amendment to the contracting laws requires an act of the Legislature, and therefore is likely to take one session to accomplish. The estimated time to resolve this hurdle is therefore about one year.

Supply System and Bonneville Construction Management Issues

The existing agreements for the construction of WNP-1 and WNP-3 give most of the construction management authority for the projects to the Supply System, subject to limited review by Bonneville. Several of the lawsuits related to the WNP-4 and WNP-5 projects called into question the effectiveness of the Supply System as a manager. There are indications that Bonneville is not willing to resume construction of WNP-1 and WNP-3 without greater involvement in the management of the projects.

The agreements between Bonneville and the Supply System were written in the early 1970s. Amending these agreements would probably require bondholder approval, and locating bondholders to secure approval would be very difficult. However, it may be possible to satisfy Bonneville's concerns by some means other than amending the agreements.

This issue of project control is a very sensitive one, and negotiations between Bonneville and the Supply System on this issue are likely to take a while. A reasonable guess is that it could take about one year to reach resolution on this issue.

Council's 6(c) Process for WNP-3

Section 6(c) of the Northwest Power Act provides that the Council may determine whether a proposal by the administrator to acquire a major (over 50 average megawatts) resource is consistent with the power plan. If the proposal is found inconsistent with the plan, the administrator can only acquire the resource after congressional action. The requirements of Section 6(c) do not apply to WNP-1 nor to Bonneville's original 70-percent share in WNP-3, since the decision to acquire these resources was made prior to the Act. However, if Bonneville exercises its option to acquire the 30 percent (275 average megawatts) share held by the four investor-owned utilities, this acquisition would be subject to Section 6(c).

The 6(c) process includes hearings by Bonneville on the proposed acquisition and preparation of a record of decision, before the proposal is placed before the Council. The Council then has 60 days to determine whether the proposal is consistent with the power plan. Overall, the 6(c) process is likely to take less than one year to complete if the proposed acquisition were found consistent with the power plan.

Nuclear Regulatory Commission Operating License Approval

After construction is underway, but before the plants go into operation, the Supply System must obtain an Operating License from the Nuclear Regulatory Commission. The licensing process typically takes place during the last three to four years of construction, and is timed so that the plant will be able to begin loading fuel as soon as construction is complete.

There are three important tasks for the license applicant in this process: 1) prepare and present a final environmental report; 2) prepare and present a final safety analysis report; and 3) prepare and present an emergency response plan. The Nuclear Regulatory Commission responds to these submissions with: 1) a final environmental statement; 2) a final safety evaluation report; and 3) an approved emergency response plan.

For WNP-1, a final environmental report has been submitted; the Nuclear Regulatory Commission has not yet prepared a final environmental statement. A final safety analysis report has been submitted; but the Nuclear Regulatory Commission has not yet issued a final safety evaluation report. No emergency response plan has been submitted, although the plan is likely to be essentially the same as the one for its neighboring plant, WNP-2. The WNP-2 emergency response plan has been accepted.

For WNP-3, the operating license status is the same as WNP-1, with two exceptions. First, the environmental requirement for WNP-3 is further along; the Nuclear Regulatory Commission has issued a draft final environmental statement for the plant. Second, as with WNP-1, the emergency response plan for WNP-3 has not yet been submitted.

In the past, the requirement for state participation in an emergency response plan has blocked the issuance of operating licenses for otherwise complete nuclear plants. Operating licenses for both Shoreham and Seabrook nuclear plants, in the Northeast were delayed by this requirement. The Nuclear Regulatory Commission now has authority to approve emergency response plans in the absence of state participation.

In short, the licensing process for WNP-1 and WNP-3 is well underway and does not appear likely to delay construction or operation of the plants. Although there is additional licensing work to be completed, it can, and ordinarily does, take place during the time the plants are being completed. The Council has been advised by the Supply System that the Nuclear Regulatory Commission has issued letters stating that there are no apparent regulatory obstacles to the completion of the plants during the 1990s.

Summary of Legal Hurdles to Completion

A summary of the legal hurdles to the completion of WNP-1 and WNP-3 is provided in Table 8-34. The estimated time to overcome each hurdle is indicated as well. Unless otherwise indicated, all times are concurrent; that is, actions proceeding toward resolution of each hurdle can occur at the same time.

Table 8-34
Summary of Legal Hurdles

Hurdle	Estimated Time to Resolve
Bonneville Environmental Impact Statement	1-1/2 to 2 years
Litigation about Bonneville EIS	0 to 4 years after EIS
Participant Opposition	2 years
Initiative 394 Study	1 to 1-1/2 years
Amend State Law for Construction Contract	1 year
Supply System-BPA Contract Management Issues	1 year
Council 6(c) Process for WNP 3	1 year
NRC Operating License Approval	1 to 2 years

The estimated times are far from certain. The speed with which these hurdles can be overcome depends a great deal on the sense of urgency--or lack of urgency--which the parties and the courts have about resolving them. Earlier estimates of the lead time required to prepare for resumption of construction were in the range of 15 to 24 months. In view of the complexity of the hurdles identified in this analysis, the Council has assumed that a minimum of three years would be required before arriving at a position where construction could be resumed. Other activities necessary to resume construction, in addition to resolution of the legal hurdles described above, include development of new cost estimates to complete construction, negotiation of new prime construction contracts, preparation of official statements for construction revenue bonds and development of a construction budget.

Availability and Cost of Construction Financing

One reason that the WNP-1 and WNP-3 were not included in the Council's 1986 portfolio was the potential obstacle to additional construction financing posed by WNP-4 and WNP-5 litigation. The WNP-4 and WNP-5 litigation has essentially been settled, ratings have been restored to Supply System bond issues and several sales of refinancing bonds consummated. These developments appear to remove a major barrier to construction financing.

Although financing might be readily obtained, other, more political factors might affect the cost of this financing.

Some participants in the Council's 1986 planning process argued that bonds to finance construction would be subject to a "WPPSS penalty" on interest rates that might range as high as two percent. The Supply System acknowledged the possibility of a penalty resulting from the WNP-4 and WNP-5 default, but recommended a fraction of a percent. The Council applied a 1-percent penalty. But, the secondary market rate on the refunding bonds, compared to similar issues, suggests a very modest penalty of 11 to 21 "basis points" (0.11 to 0.21 percent). It is unclear, however, if bond issues to complete construction would have greater or lesser penalties than refinancing issues. A penalty of no more than 15 basis points for a new construction bond issue seems a reasonable assumption at this time.

Costs to Complete Construction

Detailed estimates of the costs to complete construction were prepared by the Supply System and its contractors in 1984. These estimates, updated to January 1985 dollars and adjusted by "earned value" work accomplished during 1984 and 1985, were used in the assessment of WNP-1 and WNP-3 included in the 1986 Power Plan. Adjusted to 1988 dollars, the estimated costs to complete WNP-1 and WNP-3 used in the 1986 plan were $1,240 per kilowatt and $1,157 per kilowatt, respectively.

In 1986, the Supply System updated the 1984 estimates in support of the assessment of WNP-1 and WNP-3 prepared by Bonneville for its 1987 Resource Strategy. Adjusted to 1988 dollars, these estimated construction costs to complete the plants were $1,192 per kilowatt for WNP-1 and $1,043 per kilowatt for WNP-3. Effects of the preservation programs and work completed since 1984 were among the factors that led to reductions in the costs-to-complete estimate from the estimates used in the 1986 Power Plan.

More recently, in early 1989, the Supply System, in preparing the official statement for issuing refunding bonds, identified factors such as new Nuclear Regulatory Commission regulations that may have affected the costs-to-complete estimate since the 1986 update. The Supply System concluded that the net effect of all factors through a hypothetical 1991 construction restart would be to increase the costs to complete the plants by less than 10 percent (in constant dollars). Some further real escalation in construction costs might be expected after 1991. A 10-percent increase in the 1986 estimates would result in costs-to-complete of $1,311 per kilowatt for WNP-1 and $1,147 per kilowatt for WNP-3, in 1988 dollars. These values include anticipated real escalation through 1991. A real escalation rate of 1-percent per year is assumed to occur from 1992 through 1995. Beyond that time, real capital cost escalation is assumed to be zero. These are the values adopted by the Council for this plan.

Seismic Concerns

WNP-3 was designed to withstand potential seismic activity from faulting in the Puget Sound Basin. Subsequent improvements in the understanding of plate tectonics, in general, and of the relative motion of the tectonic plates that converge along the Northwest Coast, in particular, opened the possibility of subduction zone earthquakes of greater magnitude than fault-related earthquakes. This raised the issue of whether the design of WNP-3 is adequate to withstand the effects of a subduction zone earthquake. If the current design of WNP-3 is not adequate to withstand the forces from the postulated subduction zone earthquake, seismic upgrades at additional cost might be required.

However, studies performed by the Supply System between 1984 and 1988 concluded that WNP-3 is capable of withstanding the postulated subduction zone earthquake. The studies began with review, analysis and modeling of the Cascadia subduction zone and the WNP-3 site. Ground motions that would be produced by a subduction zone earthquake occurring at the closest point to the plant were compared to the seismic event originally used for the design of the plant. This analysis found that the plant is capable of withstanding the newly postulated subduction zone seismic event. These findings and conclusions have been submitted to the Nuclear Regulatory Commission. The Commission began review of this study in the summer of 1990.

If the findings and conclusions of this study are confirmed by the Nuclear Regulatory Commission, WNP-3 would not need redesign or retrofits to withstand a subduction zone seismic event.

WNP-1, located in eastern Washington, would not be affected by a subduction zone seismic event.

Availability of Nuclear Components

With the cessation in U.S. orders for nuclear power plants and the completion, suspension or abandonment of plants under construction, nuclear plant component production could dwindle to the point that the completion of WNP-1 and WNP-3 could be affected by the lack of equipment and materials. In preparing the 1986 plan, the Council received evidence that there was an acceptable probability that nuclear plant components and materials will remain available. The Council further suggested that additional insurance could be provided by procuring critical replacement equipment during the construction period.

The factors that led to this conclusion were: 1) the bulk of equipment for WNP-1 and WNP-3 has been procured; 2) the market for spares and replacements provided by operating plants will encourage the continued availability of components and materials; 3) the U.S. naval nuclear program will ensure the continuation of a nuclear component manufacturing industry; 4) the foreign nuclear industry will provide a continuing market for U.S. manufacturers, as well as a source of equipment for the domestic industry; and 5) it will always be possible to retool for production, albeit at greater cost for limited production runs.

These conclusions remain valid. In addition, the Nuclear Regulatory Commission has authorized the development of "commercial grade dedication" programs for certain components. In these programs, commercial-grade components are purchased and certified for nuclear applications. Given the diversity of activities supporting the continued availability of nuclear equipment and materials, there continues to be an acceptable probability that these components will be available for completion and operation of the WNP-1 and WNP-3 plants without a significant impact on costs to complete or operate.

Shared Assets Cost Allocation

WNP-1 and WNP-4 were constructed as twin plants, sharing common facilities where feasible. Similarly, WNP-3 and WNP-5 were constructed as twin plants, also sharing a common site and facilities. The participants agreement for WNP-4 and WNP-5 (units 4 and 5 were financed as a single project) allowed cost sharing with WNP-1 and WNP-3, respectively, for certain joint services and facilities on the basis of respective benefits to the projects. Representatives of the holders of defaulted bonds for the terminated projects 4 and 5 have filed suit claiming that the full costs of shared services and facilities should be assumed by projects 1 and 3, because the WNP-4 and WNP-5 interests are receiving no benefit. The additional costs to projects 1 and 3, if this suit were successful, were estimated in 1985 to be $131 million for WNP-1 and $269 million for WNP-3.

This litigation recently has become active, and it is not possible to forecast its outcome. However, the allocation of these costs will not affect costs to complete WNP-1 or WNP-3, since, if incurred, they will be borne by the region, regardless of whether WNP-1 or WNP-3 is completed.

Technical Continuity

Long-term suspension of construction could result in an increase in costs or time required to reestablish the documentation or other knowledge required to complete, test and operate WNP-1 and WNP-3. In its 1986 Power Plan, the Council concluded that the preservation programs, as planned at that time, incorporated licensing, engineering and maintenance activities adequate to ensure that technical continuity could be maintained.

A major goal of the WNP-1 and WNP-3 preservation programs was to ensure that engineering could quickly and efficiently resume without dependence on personnel familiar with the projects. A "design asset preservation program" was established in which engineering documents were packaged into a data base for each plant. This packaging was to allow a qualified individual with no prior involvement with the project to quickly pick up and complete the design effort without need to reconstruct or duplicate existing work or to consult the individual who had originated the design.

The effectiveness of the design asset preservation program was tested through Supply System, Nuclear Regulatory Commission and independent reviews. The adequacy of the program was subsequently demonstrated when the U.S. Department of Energy reviewed the design records for WNP-1 when assessing the potential for converting WNP-1 to a weapons materials production reactor. The Department's assessment found no weaknesses regarding either the completeness of the records, or the possibility of using those records to complete the design.

Operational Issues

The cost-effectiveness of WNP-1 and WNP-3 depends not only on the cost and feasibility of completing construction, but on successful operation as well. Important issues affecting operation include spent fuel disposal, operating costs and plant availability.

Spent Fuel Disposal for WNP-1 and WNP-3

Spent commercial nuclear power plant fuel contains highly radioactive fission products and long-lived radioactive transuranic elements. Originally, the nuclear power industry planned to develop commercial reprocessing plants for the separation of fission products and transuranic materials from spent fuel. This option was abandoned in the late 1970s, in part due to concerns over nuclear proliferation. In 1982, Congress passed the Nuclear Waste Policy Act making the federal government responsible for the ultimate disposal of high-level nuclear wastes. The federal government was to locate and operate a nuclear waste disposal site to be opened in 1998. In 1987, Congress selected the Yucca Mountain site in Nevada. Significant delays have occurred, and potential barriers to the Yucca Mountain site may have rendered it not viable. The Department of Energy has acknowledged the likelihood of significant delay in establishing a permanent waste repository and has announced a revised target date of 2010. Consequently, provisions will have to be made for interim storage of spent fuel. The most likely alternatives are extension of spent fuel storage capability at nuclear power plants or development of interim central waste storage facilities (see page 8-173).

The spent fuel storage racks of the WNP-1 spent fuel storage pool have been repositioned and will now provide space for the storage of spent fuel that would be produced over 15 years of operation. The WNP-3 storage pool also has been reracked and will accommodate spent fuel produced over 14 years of operation.

Given the eight-year minimum lead time required to bring either WNP-1 or WNP-3 online, it appears that sufficient spent fuel storage capability is in place at these plants to allow operation through the 2010 service date currently discussed for a federal spent fuel repository.

If additional on-site spent fuel storage capability is needed, the preferred option appears to be dry-cask storage. Two utilities, Duke Power and Virginia Power, have installed licensed dry-cask storage systems at their plant sites, and other utilities are pursuing this system.

Costs for the Virginia Power facility at its Surry plant site include $1,673,000 for a pad capable of holding 28 casks and $890,000 for each cask. Three casks are required for each year's fuel discharges. The Supply System estimates the total cost for additional on-site spent fuel storage to be $3.3 to $3.6 million per year, including capital, operating and maintenance costs. These expenditures would commence about a year prior to exhaustion of storage pool capacity.

It is not clear who will be paying the costs of additional interim spent fuel storage. Utilities operating nuclear plants have been assessed a spent fuel disposal fee by the federal government since 1982 for spent fuel disposal services originally scheduled to begin in 1998. If the government fails to take fuel at the date originally contracted, it is likely that utilities will seek compensation for the costs of extended fuel storage.

Operating and Maintenance Costs

The Council's 1986 analysis assumed that operating and maintenance costs of all new resources, including WNP-1 and WNP-3, would remain constant in real terms. But, rapid real escalation of nuclear operation, maintenance and post-operational capital replacement costs was experienced over the decade 1974 to 1984. A study by the Energy Information Administration (EIA, 1988) indicated that this cost increase is due to factors such as implementation by the Nuclear Regulatory Commission of more stringent operating requirements in the wake of Three Mile Island; increased investment by utilities in plant maintenance in an effort to improve plant availability; and increased investment in maintenance to counteract effects of plant aging.

However, the escalation of nuclear operation, maintenance and replacement costs has peaked and has declined in recent years. The period of rapid change in the nuclear industry that occurred from the late 1970s until the middle 1980s has apparently passed, and operation and maintenance costs are likely to stabilize at a lower level of real escalation. For this plan, the Council is assuming that the real rate of operating and maintenance cost escalation will decline from 3.5 percent annually in 1986 to zero percent (real) by 2000. The operation and maintenance cost assumptions used in this plan are based on operation and maintenance cost estimates used in the 1986 plan, escalated in accordance with this escalation series.

Operating Availability

The operating availability of a generating resource is critical in determining its relative cost-effectiveness in a power system. Availability is usually expressed as a percentage, representing that fraction of a year a resource is able to operate at full power. Because resources are sometimes available to operate at less than full power (derated operation), annual availability is expressed in equivalent full-power hours.

Availability is a function of planned and unplanned (forced) outages. Planned outages, such as refueling and other maintenance, can be accounted for fairly precisely. Forced outage rates are more difficult to assess and may depend on unit size, design and other possible factors. The availability of a resource should not be confused with its capacity factor, which represents actual energy production divided by plant generating capability. Capacity factors typically are smaller than availability factors because they take into account economic outages--those times when a plant is shut down for economic reasons, but could run if needed. Because the variable cost of operating nuclear plants is small, economic outages are few, and nuclear plant capacity factors typically are close to their availability factors.

The Council examined performance data maintained by the Nuclear Regulatory Commission and the North American Electric Reliability Council along with data provided by the Supply System and nuclear vendors. Assumptions regarding the operating availability of WNP-1 and WNP-3 were based on analysis of that information.

Table 8-35 contains the annual equivalent availability factors for all Babcock and Wilcox and Combustion Engineering nuclear plants. Although statistical analysis of this data cannot conclusively support a trend, availability factors in recent years are higher for many plants. This is not surprising, since the nuclear industry has invested a great deal of effort to improve maintenance and operating programs and to improve technology and plant design. As an example, data for the Babcock and Wilcox plants (WNP-1) was divided into three time periods: 1) the post-Three Mile Island era from 1980 to 1982; 2) the pre-Safety and Performance Improvement Program (SPIP) era from 1983 to 1986; and 3) the SPIP era from 1987 on. The average availability during these three eras is, 52.3 percent, 59.7 percent and 67.6 percent, respectively.

Table 8-35
Historical Availability Factors (Nuclear)
Annual Equivalent Availability Factors[a]

Plant	Average EAF	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Babcock and Wilcox:																	
Oconee 1	65.8		52.9	68.2	51.4	51.6	65.1	64.4	65.8	39.1	66.3	73.0	79.3	90.9	61.7	64.8	92.4
Oconee 2	66.3			64.0	54.3	49.3	61.7	77.2	52.1	72.4	44.4	67.0	93.7	65.8	74.7	80.2	71.2
Three Mile Island 1	37.8			77.2	60.4	76.2	79.2	12.4	0.0	0.0	0.0	0.0	0.0	11.3	67.2	70.2	75.6
Arkansas 1	59.5				52.1	68.5	72.3	44.6	50.7	65.8	52.4	43.3	61.7	69.7	48.2	79.0	65.5
Oconee 3	66.3				62.0	67.9	78.1	42.2	68.3	72.6	27.5	91.4	69.0	62.6	78.2	65.6	76.9
Rancho Seco	39.5				27.1	73.5	63.3	71.1	55.0	32.9	42.4	42.4	46.8	24.1	0.0	0.0	35.4
Crystal River 3	54.2						35.9	52.1	46.3	55.7	65.5	50.6	86.2	43.0	35.4	48.3	76.7
Davis Besse 1	38.8							39.4	28.7	55.0	40.6	63.8	55.8	25.0	0.0	63.8	16.3
Average[b]	54.2		52.9	69.8	51.2	64.5	65.1	50.4	45.9	49.2	42.4	53.9	61.6	49.1	45.7	59.0	63.8
Average[c]	58.9		52.9	69.8	51.2	64.5	65.1	50.4	52.4	56.2	48.4	61.6	70.4	54.4	52.2	67.4	67.8
Combustion Engineering:																	
Palisades	44.7	41.2	1.3	45.2	48.5	84.5	40.6	53.7	36.6	53.5	51.6	59.9	12.5	81.8	13.0	39.6	51.9
Maine Yankee	70.5		51.7	65.1	85.4	76.6	75.8	64.7	61.9	72.2	63.8	79.3	71.4	76.1	86.4	58.2	69.3
Fort Calhoun 1	70.3			52.0	60.1	74.2	71.3	91.6	57.4	67.7	88.4	65.7	56.1	73.2	86.1	73.1	67.9
Calvert Cliffs 1	69.3				89.2	65.1	61.1	54.4	60.0	79.3	69.6	72.5	81.8	56.7	75.6	68.3	66.8
Millstone Pt 1	65.8					59.8	62.0	58.5	63.9	80.2	65.8	32.7	86.5	46.6	67.8	90.7	75.1
St. Lucie 1	71.3						71.3	69.6	73.9	70.3	91.6	14.8	57.1	79.3	95.2	77.2	84.2
Calvert Cliffs 2	75.2						67.8	71.2	90.3	72.3	64.9	79.3	69.1	72.8	90.9	62.9	85.4
Arkansas 2	63.4									54.1	49.2	55.4	77.4	60.2	66.5	82.7	62.0
San Onofre 2	67.9												56.2	54.3	68.9	66.5	93.8
St. Lucie 2	77.7												78.8	83.6	83.0	78.9	64.4
San Onofre 3	76.2													51.9	72.7	80.3	99.7
Waterford 3	73.5														75.8	76.9	67.9
Palo Verde 1	53.8															47.7	59.8
Palo Verde 2	67.1															73.6	60.5
Average[b]	66.6	41.2	26.5	54.1	70.8	72.0	64.3	66.2	63.4	68.7	68.1	57.5	64.7	67.0	73.5	69.8	72.1

a Source: Nuclear Unit Operating Experience: 1985-1986 Update, EPRI #NP-5544 with updated information through 1988.
b Average is calculated using each year's equivalent availability.
c Average is calculated as in footnote 2 but excluding the years 1980-85 for TMI #1 and excluding the years 1986-88 for Rancho Seco. The argument for exclusion of this data is that these events are not vendor-related and by excluding them focus can be placed on vendor-dependent operating availability. Obviously, some risk exists that a lengthy shutdown for safety or for reasons of public opposition could occur. These risks are better treated in the overall power plan strategy, rather than attempting to quantify them into equivalent availability factors.

D:JK/90DRAFT.A11 Table 8-35

The challenge facing the Council is to predict the operating availability for WNP-1 and WNP-3 based on the data presented in Table 8-35. If the argument that the nuclear industry has improved its operating and maintenance programs is true, then using all the data, dating back to the early 1970s, would underestimate the availability factors. On the other hand, using only the data compiled after the establishment of the Safety and Performance Improvement Program yields too little information to provide confidence in the results. As a compromise, data from 1983 on was used to establish operating availability factors for WNP-1 and WNP-3.

This choice is not unprecedented. State public utility commissioners have traditionally used the last four years of availability data for rate-making purposes. They have acknowledged that data from this shorter time period more accurately reflects the operating availability, because it takes into consideration the improvements made to increase plant performance.

Historical annual availability data from 1983 to 1988 were plotted separately for both Babcock and Wilcox plants and Combustion Engineering plants. These curves, shown in Figures 8-31 and 8-32, indicate the probability that for any given year the availability of a plant will equal or exceed a certain value. These curves are referred to as duration plots.[22]

Equivalent Availability Probability

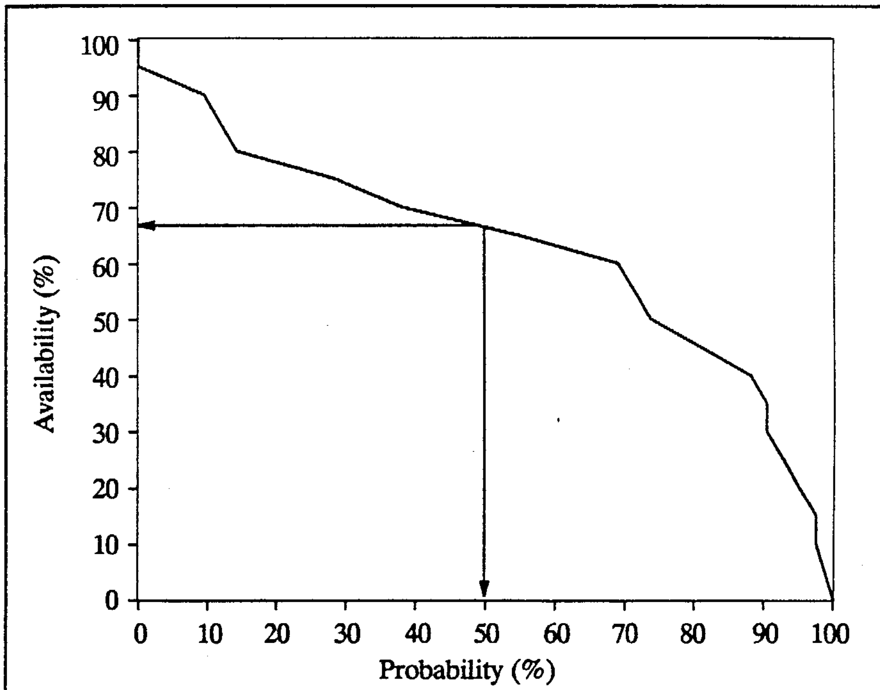

Figure 8–31
Probability of Realizing Minimum Equivalent Availability Factors for Babcock and Wilcox Plants

22./ For the Babcock and Wilcox curve, data for Three Mile Island Unit One from 1980 to 1985 were excluded as were data for Rancho Seco from 1986 on. The effects of premature plant retirements such as these, are considered in establishing service life assumptions for WNP-1 and WNP-3.

Equivalent Availability Probability

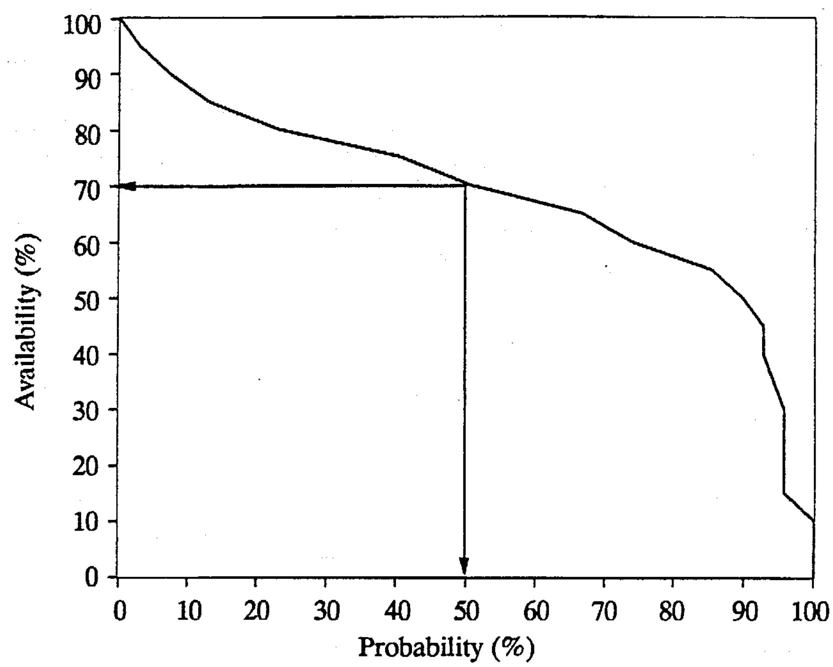

Figure 8–32
Probability of Realizing Minimum Equivalent Availability Factors for Combustion Engineering Plants

At the 50-percent probability level, the availability for WNP-1 is about 65 percent and for WNP-3 it is about 70 percent. These values are used by the Council for this plan.

Reference Energy Cost Estimates

"Reference" levelized energy costs for WNP-1 and WNP-3 are shown in Table 8-36. These costs were calculated using the reference financial and service date assumptions described in the introduction to this chapter. These include the assumption that completion of the plants would be by a developer with the financial characteristics of an investor-owned utility. This assumption, used to achieve parity of resource energy cost comparisons, is not consistent with the current ownership of WNP-1 and WNP-3 (see Table 8-38). Financing by the current plant owners would likely result in energy costs somewhat less than the costs shown in Table 8-36.

In calculating the costs of Table 8-36, the plants are assumed not to be displaceable, and costs are calculated using capacity factors equal to plant availability.

Table 8-36
Reference Energy Costs for WNP-1 and WNP-3

	Levelized Energy Costs (cents/kWh) Real ($1988)	Nominal (40 year)
WNP-1	4.1	8.0
WNP-3	3.7	7.3

Planning Assumptions for WNP-1 and WNP-3

The planning assumptions used for assessment of WNP-1 and WNP-3 in the resource portfolio are shown in Tables 8-37 and 8-38.

The financial assumptions used for assessing WNP-1 and WNP-3 are consistent with those described in Appendix 8-A for the respective classes of plant owners except for the cost of debt financing. As described above, the cost of debt financing for WNP-1 and WNP-3 is assumed to be 0.15 percent greater than the Council's general assumptions because of possible market reservations concerning nuclear issues in general and WNP-1 and WNP-3 in particular.

The sources of the planning assumptions for WNP-1 and WNP-3 are tabulated in Appendix 8-A.

Prospects for Completion of WNP-1 and WNP-3

WNP-1, if completed and operated at the costs assumed in Table 8-37, could produce about 812 average megawatts of energy at costs estimated to be about 8.0[23] cents per kilowatt-hour and WNP-3 could produce about 868 average megawatts of energy at an estimated cost of 7.3[24] cents per kilowatt-hour. These costs are less than those assumed in this chapter for the cost of electricity produced by new coal-fired power plants. WNP-1 and WNP-3 present different environmental issues than the resources that would be developed in their absence. Nuclear plants produce negligible atmospheric emissions of oxides of nitrogen, particulate material, sulfur dioxide and carbon dioxide, the major contributors to global warming concerns.[25]

23./ Reference nominal levelized costs for a hypothetical 1988 in-service date.

24./ Ibid.

25./ Some emissions of these pollutants would result from fuel enrichment operations, however, since fuel enrichment plants use large quantities of electricity and are served by utility systems employing coal-fired generation.

Table 8-37
WNP-1 and WNP-3 Planning Assumptions
(1988 Dollars)

	WNP-1	WNP-3
Total Capacity (MW net)	1,259	1,240
Total Firm Energy (MWa)	818	868
Unit Capacity (MW net)	1,259	1,240
Seasonality	None	None
Dispatchability	Must-run	Must-run
Preconstruction Lead Time (months)	36	36
Probability of Success (%)	90	90
Preservation Shelf Life (years)	Indefinite	Indefinite
Probability of Hold Success (%)	90	90
Construction Lead Time (months)	60	60
Construction Cash Flow (%/yr.)	a	b
Pre-construction Cost ($/kW)	$17.70	$19.10
Preservation Hold Cost ($/kW/yr.)	$3.80	$4.20
Construction Cost ($/kW)[c]	$1,311	$1,147
Fixed Fuel Cost ($/kW/yr.)	$0.00	$0.00
Variable Fuel Cost (mills/kWh)	5.3	5.9
Fixed O,MR&D Cost[d] ($/kW/yr.)	$86.30	$87.60
Variable O&M Cost (mills/kWh)	1.0	1.0
Earliest Service	1998	1998
Peak Development Rate (units/yr.)	1	1
Operating Life (years)	40	40
Real Escalation Rates (%/yr.)		
Capital Costs	0% to 1991, 1% for 1992-95; 0% thereafter	
Fuel Costs	3% in 1988, declining to 0% by 2000	
O&M Costs	0% to 1993, 1% thereafter	

a Construction cash flow for WNP-1 is 11/23/30/24/12%.
b Construction cash flow for WNP-3 is 4/24/33/29/10%.
c Overnight construction costs (exclude interest during construction).
d Annual per-kilowatt fixed OMR&D costs are comprised of the following:

	WNP-1	WNP-3
Fixed operation and maintenance	$64.30	$65.30
Post-operational capital replacements	$19.00	$19.30
Decommissioning fund	$3.00	$3.00

Table 8-38
Ownership Assumptions for WNP-1 and WNP-3

	WNP-1	WNP-3
Consumer-owned Utilities (%)	100%	70%
Investor-owned Utilities (%)	0%	30%

On the other hand, the issue of nuclear spent fuel disposal has yet to be resolved, and public concerns remain regarding reactor safety. It is argued by many that the environmental risks associated with a nuclear accident greatly outweigh the environmental advantages of operating nuclear plants. Public comments received by the Council on this issue have been extremely polar. Any attempt to complete either of these plants would likely encounter substantial legal and political challenges.

After reviewing the information and discussion contained in this section, the Council is requesting that Bonneville and the Supply System take appropriate steps to determine whether WNP-1 and WNP-3 should continue to be preserved. As described further in Volume II, Chapter 1, the Council is calling for Bonneville and the Supply System to examine the principal legal and engineering tasks that would be required to resume construction on WNP-1 and WNP-3. The Council is asking Bonneville and the Supply System to pursue those activities that yield the greatest benefit in reducing uncertainty about whether the plants can be completed in a timely manner if needed, resolving the less expensive issues first, before committing significant effort to problems that will be more expensive to address. In most instances, resolving these issues also will shorten the lead time that would be required to place these resources on line.

New Nuclear Fission Technology

The nuclear industry and the federal government have, over the past several years, been developing advanced nuclear power plant designs intended to address some of the problems confronting the nuclear industry. Objectives of these advanced designs include improved economics, reduction in investment risk and improved safety. This is to be accomplished by reduced plant size, increased factory fabrication, increased reliance upon "passive" safety systems requiring no operator intervention, general simplification of design, increased safety margins, improved maintainability and improved operator-machine interfaces. Guiding the development of advanced designs is a philosophy of avoiding revolutionary design changes in favor of an evolutionary approach that begins with refinement of current designs.

Advanced Nuclear Plant Designs

Three generations of advanced designs are under development. "Large evolutionary" designs are based on incremental improvements to existing light water reactor designs. These plants are available for overseas order and are expected to be approved for construction in the United States in the early 1990s. "Small evolutionary advanced" designs use current light water reactor technology, but would incorporate significant downsizing and passive safety features. These designs may be available for order by the mid-1990s. Finally, "modular advanced" designs would use non-light water reactor technology and would incorporate extreme downsizing, a high degree of modularity and passive safety features. Modular advanced designs probably will not be available for order until the turn of the century.

Large Evolutionary Plants

Two U.S. vendors are actively developing large evolutionary advanced designs for the international market and for submittal to the Nuclear Regulatory Commission for certification. These are General Electric's Advanced Boiling Water Reactor (ABWR) and the System 80+ by Combustion Engineering. These designs are essentially refinements of these vendors' earlier light water reactor designs. They retain the large scale (1,200 megawatts capacity) and general engineering features of predecessor designs.

The Advanced Boiling Water Reactor is an evolutionary version of existing General Electric boiling water reactors such as WNP-2. Design of this plant has been underway since 1978, under the auspices of an international consortium of boiling water reactor vendors. The Advanced Boiling Water Reactor is intended to incorporate the best features of the earlier boiling water designs offered by participating vendors. Distinguishing features include a simplified coolant recirculation system, triple-redundant emergency core cooling, improved containment, and improved control and instrumentation systems. Two 1,365-megawatt units have been ordered by the Tokyo Electric Power Company for construction beginning in 1991 at the Kashiwazaki-Kariwa station. Commercial operation of the first unit is scheduled for 1996 and the second unit in 1998.

The Combustion Engineering System 80+ is a refinement of the Combustion Engineering System 80 designs used at Palo Verde 1-3 and at WNP-3. Operating experience at Palo Verde is being used to guide design improvements, as is the experience of Duke Power, one of the more successful U.S. nuclear utilities. The principal design changes involve improvements to the containment building, the emergency core cooling system, a safety depressurization system, increased thermal margins and improved control room design. The System 80+ is scheduled to be certified by the Nuclear Regulatory Commission in Fiscal Year 1992. No orders have been reported.

Because they have not yet been built or tested, the cost and performance characteristics of large evolutionary designs remain somewhat speculative. Performance estimates published by the Electric Power Research Institute (EPRI, 1986), adjusted to 1988 dollars are shown in Table 8-39. The range of capital costs shown in Table 8-39 are based on estimates prepared by Combustion Engineering for the System 80+ (low end) and the estimated cost of the General Electric units to be constructed by Tokyo Electric (high end). Because these plants represent refinements of current nuclear technology, actual construction costs are likely to be similar to those of the better plants recently completed.

Table 8-39
Large Evolutionary Nuclear Plants - Planned Characteristics

Primary Fuel	Enriched Uranium
Rated Capacity (Net MW)	1 unit @ 1,100
Average Heat Rate (Btu/kWh)	10,530
Availability (%)	68
Siting and Licensing Lead Time (months)	60
Construction Lead Time (months)	72
Siting and Licensing Cost ($/kW)	Not available
Construction Cost, ex. of AFUDC ($/kW)	$1,150 - $1,700
Fixed Fuel Cost ($/kW/yr.)	Comparable to current designs
Variable Fuel Cost (mills/kWh)	Comparable to current designs
Fixed O&M Cost ($/kW/yr.)	Slightly less than current designs
Variable O&M Cost (mills/kWh)	1.0
Capital Replacement ($/kW/yr.)	Slightly less than current designs
Operating Life (years)	40

Small Evolutionary Advanced Plants

The small evolutionary advanced nuclear power plants would represent a major departure from contemporary nuclear power plant design. Though using conventional light water reactor technology, these plants would be considerably smaller than current designs, would use greatly simplified mechanical and electrical systems, and would employ passive safety systems requiring no operator intervention for many hours following an abnormal occurrence. These designs are expected to have greatly improved performance and cost compared with contemporary designs. Examples of the performance objectives for small evolutionary designs, prepared by the Electric Power Research Institute, include 87-percent availability, a four-year construction period and a 60-year operating life (Stahlkopf, 1988).

Two small evolutionary advanced designs are being developed. The Westinghouse AP-600 would employ conventional pressurized light water technology in a 600-megawatt plant, featuring overall simplification, a passively actuated and operated emergency core cooling system, and advanced instrumentation and control systems. A three-year construction schedule is targeted, with a five-year overall lead time from order to commercial operation. Construction costs are estimated to be $1,270 to $1,500 per kilowatt (Electrical World, 1988; Stahlkopf, et al., 1988). The AP-600 is being developed under a program jointly funded by the Electric Power Research Institute and the U.S. Department of Energy.

The General Electric Small Boiling Water Reactor (SBWR) would be based on conventional boiling light water reactor technology. This plant also would be in the 600-megawatt size range, and also would employ passively actuated and operated emergency core cooling. This design also is being developed under the Advanced Light Water Reactor program of the Electric Power Research Institute and the U.S. Department of Energy.

Modular Advanced Plants

Modular advanced reactors would employ alternatives to the conventional light water reactor technologies used in the current generation of commercial nuclear plants to achieve the objectives of improved performance and safety, and lower construction and operating costs. Most of the proposed designs are highly modular, with unit sizes ranging down to the 100 to 200 megawatt level. These small sizes would permit greater factory fabrication, better quality control, shorter construction lead time and would allow for improved containment of radioactive materials. Several design concepts envision arrays of small reactors operated by a central control room and supplying a common turbine-generator to capture some of the economies of scale associated with larger plant sizes.

Examples of this generation of advanced designs include the Asea Brown-Bovari PIUS, the General Atomic Modular High Temperature Gas-Cooled Reactor and the General Electric PRISM. These designs are currently at the conceptual stage of development. It is not expected that they would be certified for commercial use prior to 2000.

Environmental Considerations

This section presents an overview of the principal impacts a nuclear power plant could have on the environment. A summary of the general air, water, waste and land-use impacts is provided, as well as description of mitigating measures. Many of the environmental impacts of nuclear generating plants are those common to other central-station generating facilities. This discussion is general (i.e., not plant-specific) and focuses upon unique aspects of nuclear plants.[26]

Atmospheric Impacts

The primary atmospheric impacts resulting from the construction of a nuclear power plant are localized and common to large construction projects. They include an increase in atmospheric dust due to removal of existing groundcover during construction activities and a decrease in air quality due to pollutants related to automobile exhaust.

The potential atmospheric effects of nuclear power plant operation occur as a result of heat and moisture released from the plant cooling system, cooling tower drift, transmission line corona discharge and release of airborne radioactive materials. With the exception of airborne radioactive effluents, these effects are common to all large thermal generating facilities. Oxides of sulfur, nitrogen and carbon dioxide are not released in significant quantities by an operating nuclear power plant. Fuel enrichment, an electricity-intensive process, will, however, result in some release of these materials, since U.S. fuel enrichment plants are supplied by utility systems using coal-fired generation.

26./ The material in this section is adapted from Battelle, Pacific Northwest Laboratories. *Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest, Volume XIV: Nuclear.* Prepared for the Northwest Power Planning Council in April 1983.

Airborne radioactive effluents can be divided into several groups. First are isotopes of the fission-produced noble gases, krypton, xenon and argon. These do not deposit on the ground and are not absorbed and accumulated within living organisms. Treatment of noble gas effluents generally consists of collection, hold-up to permit decay of shorter-lived isotopes, followed by release. Noble gas isotopes act primarily as a source of direct external radiation emanating from the effluent plume.

A second group of airborne radioactive effluents, the fission-produced radioiodines, as well as carbon 14 and tritium, also are gaseous, but these effluents tend to be deposited on the ground and/or inhaled into the body. Because these are active elements that may be incorporated within the body, concentrations of iodine in the thyroid and of carbon 14 in bones are of particular significance. Currently, iodine 131 is captured by filtration through charcoal beds. Carbon 14 and tritium are released.

The third group of airborne effluents consists of particulates. These include fission products, such as cesium and barium, and activated corrosion products, such as cobalt and chromium. Particulates are controlled by filtration in high-efficiency particulate filters.

Federal regulations[27] specify limits on levels of radiation and limits on concentrations of radionuclides in releases in the air and water. These regulations state that no members of the general public in unrestricted areas shall receive a radiation dose as a result of facility operation of more than 0.5 rem[28] in one calendar year or, if an individual were continuously present in an area, 2 millirem in any one hour or 100 millirem in any seven consecutive days to the total body. Experience with the design, construction and operation of nuclear reactors indicates that average annual releases of radioactive material and effluents typically will be small percentages of federal limits.

Water Impacts

Potential water-related effects of nuclear power plant operation include thermal discharges, release of waterborne chemical pollutants, water consumption and release of waterborne radioactive materials.

Because of potential thermal impacts to aquatic organisms residing in surface waters, either through raising of the temperature of the receiving waters or by thermal shock accompanying changes in plant operation, most contemporary power plants use the atmosphere as a heat sink. This is accomplished by use of closed-cycle cooling involving the use of cooling ponds, lakes or canals, or natural-draft or mechanical-draft cooling towers for heat exchange with the atmosphere.

27./ 10 Code of Federal Regulations 20 Standards for Protection Against Radiation.

28./ A rem is the dosage of any ionizing radiation that will cause the same amount of biological injury to human tissue as one roentgen of high-penetration x-rays. A millirem is one-thousandth of a rem.

Due to partial evaporation of the coolant in evaporative cooling towers, the natural concentration of contaminants, such as mineral salts, that enters the system in the make-up water continually increases. These increases are controlled through periodic blowdown of the coolant. Portions of the coolant are withdrawn and replaced with fresh coolant. Because of the concentration of impurities, the blowdown can be environmentally damaging when discharged to receiving waters. Waste water treatment techniques can be used to remove impurities prior to discharge of the withdrawn coolant. "Zero discharge" plant designs incorporating total recycle of plant water are available. Typically, a large power plant, whether nuclear or fossil, requires about 40 or 50 cubic feet per second of cooling water make-up, assuming it uses evaporative cooling towers. About two-thirds of this amount is evaporated into the atmosphere and one-third is returned to the receiving water body as withdrawn coolant. The effect of water withdrawals and discharges of this magnitude depends on the affected water body.

In addition to thermal discharges, there may be release of waterborne radioactive materials, including fission products such as nuclides of strontium and iodine, activation products such as sodium and manganese, and tritium. Standards are established to control internal doses, if any, from fish consumption, from water ingestion (as drinking water), from eating and any direct external radiation from recreational use of the water near the point of discharge. Monitoring programs are established to verify that standards are not exceeded.

Solid Radioactive Waste Disposal

Radioactive isotopes produced as a result of reactor operation include fission products, actinides and activation products. Fission products are radioisotopes formed as the products of the fissioning of uranium and plutonium during reactor operation. Actinides are the isotopes of elements, of atomic weight 89 (actinide) and greater. For commercial reactors, the actinides of greatest significance include residual amounts of unfissioned uranium fuel plus unfissioned plutonium and other actinides formed by transmutation of uranium during reactor operation. Activation products include radioisotopes formed by neutron flux during reactor operation.

The classes of radioisotopes described above appear in a variety of physical and chemical forms during the course of reactor operation. Airborne particulates and gaseous wastes were discussed earlier; the solid waste forms will be discussed here.

Techniques for treatment and disposal of radioactive waste depend upon the physical and chemical characteristics of the waste form as well as the radiological characteristics of the contained isotopes. For purposes of determining the general method of final disposal, radioactive waste is classified as high-level waste, transuranic waste or low-level waste.

High-level waste has high concentrations of beta and gamma-emitting isotopes and significant concentrations of transuranic materials (isotopes of neptunium and heavier elements including plutonium). The only reactor product within the category is spent fuel. Spent reactor fuel is held in storage at reactor sites, pending the completion of a federal repository for spent fuel.

Transuranic wastes have low levels of beta and gamma emissions but significant concentrations of transuranic isotopes. Transuranic wastes are produced during normal reactor operation, but are contained within the spent fuel elements unless the fuel cladding is breached.

Low-level wastes are characterized by relatively low levels of beta or gamma emissions and insignificant concentrations of transuranic materials. Low-level wastes produced during reactor operation include gaseous waste, compactable and combustible wastes, concentrated liquids and wet wastes, and non-combustible operating and decommissioning wastes. Disposal of low-level wastes is either by dilution to acceptable levels and release or by shallow land burial. Compactable and combustible wastes are reduced in volume by compaction and incineration, followed by packaging and deposition in shallow land burial sites. Liquids and sludges are solidified, packaged and placed in shallow land burial sites. Non-combustible operating and decommissioning wastes are packaged and placed in shallow land burial sites.

Originally, it was planned to develop commercial reprocessing plants for the separation of fission products and transuranic materials from commercial spent fuel. Elements with no commercial use would be placed in suitable permanent disposal facilities while unburned uranium and transuranics would be recycled as refabricated nuclear fuel.

In the late 1970s, the United States, because of nuclear proliferation concerns, abandoned the reprocessing option and chose to dispose of spent commercial fuel in permanent repositories. Congress, in 1982, passed the Nuclear Waste Policy Act making the federal government responsible for the ultimate disposal of high level nuclear wastes, which include spent nuclear fuel. Operators of nuclear plants were required to contract with the federal government for spent fuel disposal services as a condition for maintaining the operating license for their plants. Payment for this service was set at 1.0 mill per kilowatt-hour, with adjustments to be made as the costs of this service were better defined. This contract specified that the U.S. Department of Energy will take title to the spent fuel and begin disposal operations no later than January 31, 1998.

Significant delays occurred in the federal spent fuel disposal program due to management issues and resistance by the states being considered for the waste repositories. In 1987, Congress passed the Nuclear Waste Policy Amendments Act designating Yucca Mountain, Nevada, as the single site to be developed. The Department of Energy is to proceed with development there if site characterization proves satisfactory.

Progress on nuclear waste management continues to be disappointing. Because of contractor litigation, quality assurance program preparation delays, lack of a permanent program direction and opposition from the state of Nevada, site development has not yet begun. The Department of Energy has announced a delay in the start-up of the repository to 2010.

All commercial reactor plants are equipped with a spent fuel storage pool. The purpose of this pool is to provide interim spent fuel storage to allow highly radioactive, but relatively short-lived, radioisotopes to decay, facilitating subsequent handling of the fuel. Until the federal government develops facilities for the storage or disposal of spent fuel, spent fuel is being stored at the reactor site in the spent fuel storage pools or at on-site dry storage facilities.

In view of the anticipated delays in establishing permanent spent fuel disposal capability, utilities, the Electric Power Research Institute and the U.S. Department of Energy have been investigating options for providing additional on-site spent fuel storage. Options that have been considered include the following:

- Reracking of existing spent fuel storage pools with high-density fuel racks to permit storage of additional fuel elements. Reracking has been completed at WNP-1, WNP-2 and WNP-3.
- Fuel assembly consolidation to increase the density of spent fuel stored in existing pools.
- Additional on-site spent fuel storage pools.
- On-site dry storage vaults, silos or drywells. These would hold spent fuel that has aged to the point at which decay heat could be removed by air-cooling.
- Dry storage casks placed on on-site concrete storage pads. These would be used for storage of aged spent fuel.

In addition to the options described above, improved nuclear fuel design has reduced the amount of spent fuel produced by plant operation.

Land Use Impacts

The land uses for a nuclear power plant include the land required for the project itself, as well as transmission, railroad spur and highway access rights-of-way. Typically, the land-use requirements for a large nuclear station will be one to two square miles. The developed area for WNP-1 (including the terminated WNP-4 plant) is about 972 acres. The developed site area for WNP-3 (including the terminated WNP-5 plant) is about 270 acres. In addition, an exclusion area with a 0.8-mile radius (about two square miles) surrounds each site. Railroad, highway, transmission and water intake and outfall lines are typically less than several miles in length each.

Not all of the land that is set aside for a nuclear plant is affected by construction. Typically, about 100 to 200 acres of the land is converted from its present condition to other uses. These uses include construction of the buildings, structures and laydown areas. Much of the exclusion area remains in natural condition or in low-intensity land use.

Soil erosion can be a significant problem at a large construction site. Special soil management practices are typically required to minimize adverse land and vegetation impacts during construction. Where there are small streams, erosion of exposed soil must be controlled to control sediment load, and disturbance of vegetation along the stream's banks must be minimized.

Fish and Wildlife Impacts

The principal impacts of nuclear power plants upon fish and wildlife result from withdrawal of water for waste heat rejection and from preemption of habitat by the plant.

Nuclear power plants require more cooling water and produce more waste heat than a fossil fuel plant of comparable capacity. But with the closed-cycle cooling systems, thermal loading of aquatic ecosystems is not a crucial issue, provided the power plants do not withdraw from waters of critical environmental concern.

Cooling water withdrawal presents a potential for impingement and entrainment of fish and other aquatic organisms. Impingement and entrainment impacts are highly variable, depending on plant location and physical and biological phenomena at each site.

On-site storage, transfer and disposal of radioactive wastes are expected to result in no damage to the environment or to fish and wildlife.

Prospects for New Nuclear Plants in the Pacific Northwest

Three generations of new nuclear power plant designs are presently under development. The most advanced of these (in the sense of schedule) are the so-called Large Evolutionary Advanced Plants. These plants are basically refinements of existing models offered by U.S. vendors, and are expected to be certified for U.S. construction by the Nuclear Regulatory Commission by the early 1990s. The first are expected to see service in Japan in the late 1990s. There is little evidence of interest in these plants by any U.S. utility, because they would face many of the development issues faced by conventional light water commercial reactors. Though these plants might offer somewhat improved constructability and performance, they will retain the large size and active safety systems of current designs. Because of the investment risk presented by such large plants, lengthy construction period, and the large plant size, the Council has not included these plants in its resource portfolio.

The small evolutionary plant designs would address some of the major development issues associated with nuclear power. Cost uncertainties will likely be reduced and public acceptance might improve because of passive safety systems and improved cost and schedule certainty. Smaller plants, shortened construction time, and greater cost certainty should help alleviate investment risk. These plants might be available for commercial operation in the 2000 to 2002 period.

Finally, modular advanced designs may be certified for construction near the end of the century. These designs would further reduce investment risk by using much smaller unit sizes. Plant safety should be improved, in an absolute sense, by improved containment of radioactive materials and innovative system design. Cost reductions and greater cost certainty should be achieved by using extensive factory fabrication. Commercial units probably will not see service before 2005. There is a possibility that the Northwest might see a demonstration unit using modular advanced technology, because the U.S. Department of Energy is considering construction of a tritium production reactor with this technology at the Idaho

National Engineering Laboratory. This plant could come online around the end of the century.

None of the advanced designs address the issue of high-level waste disposal. By providing additional on-site spent fuel storage, utilities can prolong plant operation until such time as a high-level waste repository is developed. Alternatively, the federal government or utilities could develop centralized monitored retrievable storage facilities for interim storage of spent fuel.

The more advanced design concepts, the Small Evolutionary Advanced plants and the Modular Advanced plants, feature smaller unit sizes, passive safety systems and other features enhancing their attractiveness. But there is great uncertainty with respect to the time when these plants will be available for construction. Because they are at such an early stage of development, their cost and performance characteristics also are highly uncertain. Current cost and performance estimates appear attractive, but most likely are optimistic design goals and may not be realistic. Because of these uncertainties, advanced nuclear technologies do not appear, at this time, to be reliable and available within the meaning of the Northwest Power Act and therefore are not included in the portfolio. The Council will continue to monitor new nuclear technologies and reassess them as part of future power plans.

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Ocean Energy Resources

Because of their great surface area, the oceans and their overlying atmosphere absorb most of the solar energy intercepted by the Earth. The oceans also receive energy through the gravitational attraction of the moon and sun, and geothermal energy from the sea floor. These various sources of energy are manifested as wave power, marine biomass growth, oceanic winds, salinity gradients, thermal gradients, tidal power and ocean currents. Because of their larger area the oceans may offer a greater source of renewable energy than the earth's land offers.

Many concepts have been advanced for producing useful power from ocean energy sources. For several reasons, few of these proposals have achieved commercial viability. First, although the absolute amount of energy from oceanic sources is very large, ocean energy resources tend to be very dilute. The equipment required to capture this energy and to convert it to a useful form must be massive and, therefore, costly. Second, the ocean is a hostile environment. Storm surges, corrosion, moisture, motion and fouling by marine organisms place demanding requirements on the design and maintenance of marine energy conversion equipment. Finally, many sources of oceanic energy are intermittent and cyclical, lessening the value of power produced from these sources.

The following oceanic sources of power are investigated in this section:[29]

- wave power;
- marine biomass production;
- salinity gradients (salinity differences) between marine waters and fresh water discharges from streams;
- tidal power;
- ocean currents; and
- thermal gradients (temperature differences) between surface waters and waters at depth.

In this section, the technology available to exploit each of these resources will be described, along with special issues related to the resource, the potential size of the resource in the Pacific Northwest, and estimated costs of energy from the resource.

29./ In addition to the renewable resources listed, natural gas and petroleum resources are suspected to be present off the Northwest coast. The future price and availability of fossil fuels for electric power generation is examined separately by the Council.

Ocean Wave Power

The extraction of electrical power from ocean waves has been under consideration since the 19th century. Hundreds of patents were filed on wave energy conversion devices between 1900 and 1930. Bouchaux-Praceique constructed the first operating system in France in the early 20th century. Interest intensified following the increase in petroleum prices in 1973, and major research programs were established in Great Britain, Norway and Japan.

Theoretical understanding of wave energy conversion has been greatly advanced during the last two decades. Many conceptual designs have been analyzed, some theoretically capable of very high energy conversion efficiencies. Extensive laboratory analysis and field testing of scale models was conducted by the British prior to termination of the government program in 1985. The Japanese installed several full-scale pneumatic wave-energy conversion systems on the KAIMEI wave energy test barge, which supplied energy to the Japanese grid briefly in 1980. More recently, the Japanese have deployed a 30-kilowatt shoreside system using the pneumatic technology tested on KAIMEI. The Japanese also market a small (60 watt) buoy-mounted pneumatic wave energy device for powering maritime navigational aids. Norwegian work has been directed to shoreside conversion devices that use wave-focusing structures to concentrate wave energy. A 500-kilowatt pilot plant using wave-focusing structures and a pneumatic turbine was installed by Kvaerner Brug A/S at Toftovstallen, near Bergen. This plant operated commercially from November 1985 until January 1989, when it was swept off its foundation and destroyed in a severe storm. A second 350-kilowatt plant using wave-focusing structures and a hydraulic turbine, referred to as TAPCHAN, has been installed by Norwave A/S, also near Toftovstallen.

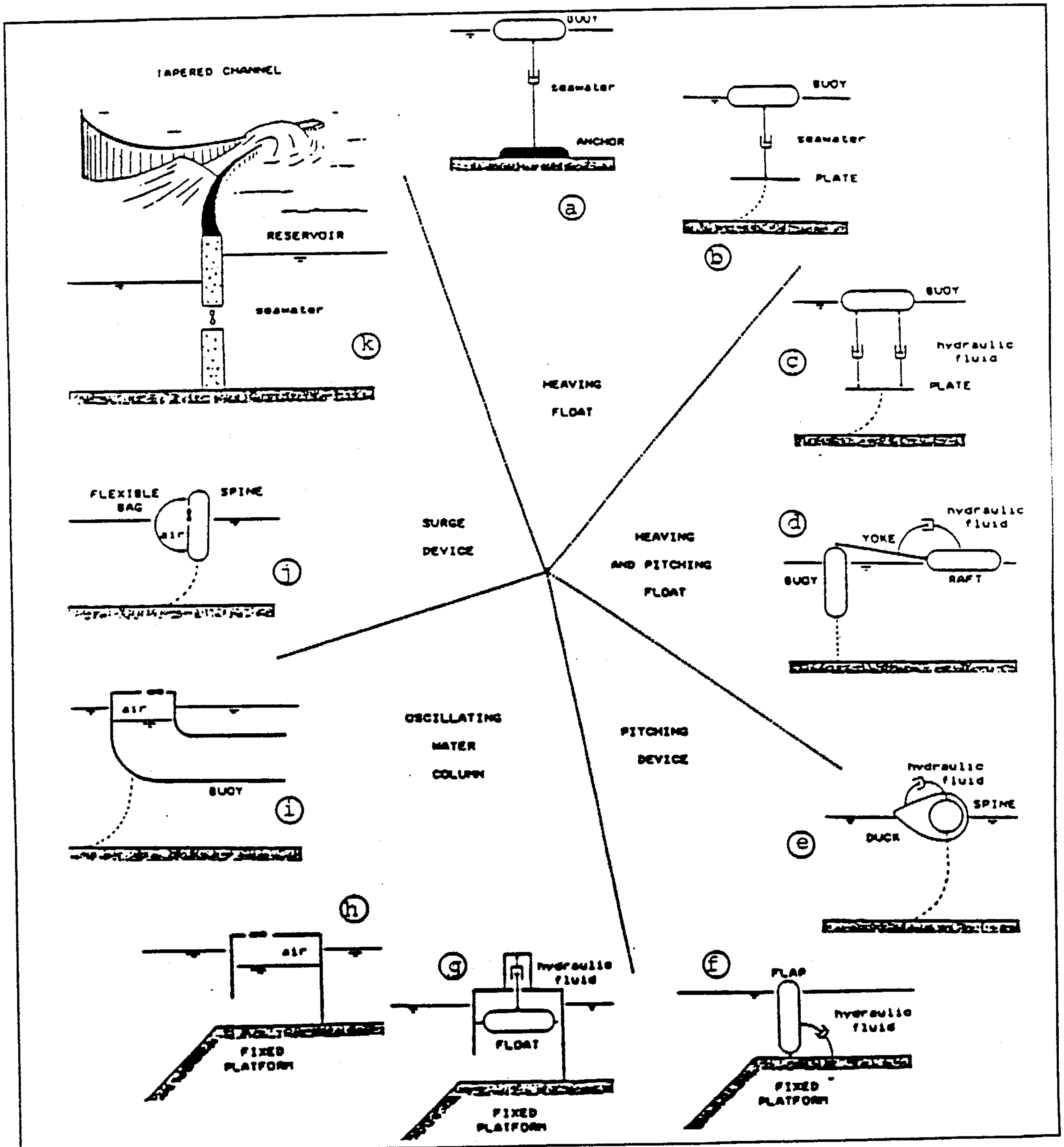
Although there is currently no U.S. government funding of wave power studies, Virginia Power, the North Carolina Alternative Energy Corporation, the state of Hawaii and Pacific Gas and Electric Company are funding wave energy resource assessments and economic feasibility studies.

Wave Power Technology

Wave energy conversion devices can be classified by the type of energy absorption mechanism, working fluid (pneumatic or hydraulic) and whether fixed or floating. Figure 8-33 illustrates the principal designs showing promise for commercial application.

Wave Power Plants

Figure 8–33
Wave Power Plant Conceptual Designs



Heaving float devices employ the vertical motion of a wave-actuated buoy to operate a pump. The pressurized working fluid operates a turbine generator to produce electricity. In one variation of the heaving buoy design, the pump is anchored to the sea floor (see Figure 8-33(a)). The Danish Rasmussen KN System is of this type. A 1-kilowatt prototype of this design has been tested at sea (Hagerman and Heller, 1988). Alternatively, the pump can be anchored to a submerged horizontal plate that acts as a sea anchor (see Figure 8-33(b)). The Swedish Gotaverken Hose Pump is of this design. A 30-kilowatt prototype of the hose pump has been tested at sea.

Devices using combined heaving and pitching floats theoretically are more efficient than devices limited to heave, because energy is absorbed from both motions. The Canadian NORDCO Wave Energy Module (see Figure 8-33(c)) uses a buoy, free to pitch and heave, with hydraulic pumps mounted around its circumference. The pumps are secured to a submerged flat plate. A 1-kilowatt prototype of this design has been tested on Lake Champlain. The Sea Energy Corporation, a U.S. firm, has developed the Contouring Raft (see Figure 8-33(d)), in which pumping motion is developed between a fixed buoy and a raft free to pitch and heave. Wave tank tests of a 1/15-scale model of this device have been conducted.

Pitching devices capture energy from wave-induced pitching motion. The British Salter Nodding Duck (see Figure 8-33(e)) uses the rotational movement of a series of cam-shaped floats mounted along a floating spine to pump hydraulic fluid through turbine-generators. A 1/10-scale model of this device has been tested on Loch Ness. The Q Corporation, a U.S. firm, has developed the Tandem Flap (see Figure 8-33(f)). The Tandem Flap uses twin flaps, hinged on a sea-floor foundation (only one flap is shown in the figure) to capture wave energy. The flaps power hydraulic pumps that drive a turbine-generator. A 20-kilowatt prototype of this design has been tested in Lake Michigan. The feasibility of this device, as with other devices mounted on the sea floor, is dependent upon depth and bottom conditions.

Oscillating water column (OWC) devices use wave motion to establish a vertically oscillating water column in an enclosed chamber. The Neptune system of the Australian firm, Wave Power International, uses a buoy floating on an oscillating water column contained within a bottom-mounted enclosure to power hydraulic pumps (see Figure 8-33(g)). The pressurized hydraulic fluid operates a turbine generator. A 1/12-scale model of this device has been tested in a wave tank. Most oscillating water column devices use the air displaced by the oscillating water column to drive an air turbine directly. An example is the Norwegian Kvaerner Brug Multi-resonant Oscillating Water Column (see Figure 8-33(h)). As mentioned earlier, a commercial-scale (500-kilowatt) unit operated at Toftovstallen, near Bergen, from November 1985 until January 1989.

Most OWC designs are shore or bottom-mounted. However, one design, the Backward Bent Duct Buoy (BBDB) of the Japanese Ryokuseisha Corporation, is a floating device (see Figure 8-33(i)). The ability to float would free OWC devices from the limitations of shore or near-shore locations. A 1/10-scale prototype BBDB has been tested at sea. A small-scale OWC generator for powering maritime navigational aids is commercially produced in Japan.

Surge devices extract energy from forward horizontal wave forces. The British Sea Energy Associates (SEA) Clam (see Figure 8-33(j)) is one such device. Each clam would consist of a ring-shaped hollow float (spine) moored offshore. Air bags attached to the exterior sides of the clam would be alternately compressed and reinflated by the incident waves. The compressed air would drive air turbines to produce electricity. A 1/10-scale model of a straight-spine clam (a less efficient earlier design) has been tested on Loch Ness. The Norwegian Norwave Tapered Channel (TAPCHAN) power plant (see Figure 8-33(k)) is another design employing wave surge energy. In this design, a tapered channel leading to the shore-mounted plant is used to focus and amplify wave crest heights. After passing through the channel, the waves spill into a reservoir. Water from the reservoir is directed back to sea through a turbine generator. A 350-kilowatt TAPCHAN is operating at Toftovstallen.

Wave Power Development Issues

Wave energy power plant designs generally are in an early stage of development, and long-term prototype testing and commercial demonstration would be required prior to large-scale deployment in the Pacific Northwest. Prototypes of numerous conceptual designs have been tested, but the only designs that have been commercially demonstrated are shore-mounted devices (the Norwegian Kvaerner oscillating water column and Norwave TAPCHAN plants). Because of land-use conflicts and aesthetic considerations, it seems unlikely that shore-mounted devices could be deployed extensively in the Northwest. Further development and full-scale demonstration of offshore technologies are required. Major technical problems remain to be resolved, including the demonstration of mooring and electric power transmission systems, and the development of power conversion equipment (pumps, turbines, etc.) reliable enough to allow unattended operation. Storm-caused wave energy surges and the corrosiveness, moisture and motion of the marine environment pose severe challenges to the reliability and longevity of wave power equipment. Mooring and submarine power cable technologies used for offshore oil exploration and production show promise for adaptation to wave energy conversion systems.

Integration into the regional power system may be difficult because of the intermittency of wave power. Even if technically proven, it is not clear that wave-generated energy can be economically competitive with alternative resources. Although preliminary estimates suggest that certain wave power systems are potentially cost-effective compared with conventional coal-fired power plants, considerable development and testing of wave power devices are required to confirm the cost and performance of these devices.

Near-shore wave energy conversion devices may create "wave shadows." The sensitivity of shore areas to these impacts may vary, allowing wave energy to be developed in certain localities and not in others. The nature and magnitude of these impacts are not well understood. Offshore devices are less likely to produce this effect, because waves passing through the power plant will lose only a portion of their energy. Furthermore, waves passing through gaps between the plants will diffract, reestablishing a wave field behind the plants. Sections of the nearshore environment may change from high to low energy. This may affect longshore sediment transport and beach stability. Ecosystem composition and productivity may change.

The aesthetic impacts of offshore wave energy power plants should be minor, but shore-mounted devices might have significant aesthetic impacts. Offshore devices would have to be sited and marked to protect navigation. Drifting units, broken from their moorings, could pose a threat to navigation and could create aesthetic impacts and property damage if washed ashore.

Restricted funding for research and development is the most significant constraint to development of wave energy systems. Concerns about the potential environmental impact of these devices on sensitive coastal areas may constrain siting and licensing of wave energy systems.

Wave Power Potential in the Pacific Northwest

Waves are produced by the action of wind blowing over water. Wave energy is roughly a fifth-power function of wind speed; therefore, small variations in windspeed may produce extreme daily and seasonal fluctuations in wave energy. Wave energy fluctuations are, however, tempered by the inertia of water and by swells originating from distant storms. Wave power in the Pacific Northwest peaks in winter. Computer simulations based on observations during 1974 and 1975 showed average monthly wave power off the Northwest coast to have a seasonal variation of a factor of 20 (Pierson and Sali, 1986). In a recently completed study for Pacific Gas and Electric Company, SEASUN Power Systems, using measured data, estimated that quarterly average incident wave power off northern California varies by a factor of 4 to 6 between winter and summer (Hagerman, 1989).

The wave energy of the mid- and North Pacific coast is the best of any coastal area in the United States. The estimated average wave power at near-shore locations ranges from 6 to 9 kilowatts per meter of wave crest. Offshore, the estimated average wave power is 37 to 38 kilowatts per meter of wave crest. The wave power potential of the roughly 350 mile coastline of Washington and Oregon is approximately 3,400-5,100 megawatts for near-shore sites or 21,000 megawatts for offshore sites. Wave power devices for offshore deployment should have energy conversion efficiencies of at least 12 percent. This suggests the technical wave energy potential for the Pacific Northwest, using current technology, might be within the range of 400 to 2,500 average megawatts. Factors such as the need to maintain clearance between units, plant unavailability, electrical losses (conversion system and transmission losses) and site limitations due to navigational, aesthetic or other environmental reasons would reduce this technical potential.

Cost and Performance of Wave Power Devices

Only preliminary cost information is available for most wave power system designs. Detailed engineering cost estimates, however, are available for the government-sponsored British devices, including the SEA Clam. The Massachusetts Institute of Technology (under contract to the Electric Power Research Institute (EPRI)) prepared cost estimates for an array of SEA Clams, scaled to wave conditions of the Pacific Coast (EPRI, 1986). The estimated cost and performance characteristics of this array are shown in the first column of Table 8-40.

Table 8-40
Cost and Performance Characteristics for Ocean Wave Power Units (1988 Dollars)

Type	Straight Spine SEA Clam	Gotaverkin Hose Pump
Location	North Pacific Coast, Offshore	North Atlantic Coast, Offshore
Number of Units	25 @ 7.9 MW each	Not available
Rated Capacity	198 MW (net)	64 MW
Capacity Factor	17%	37%
Construction Cost	$6,950/kW	$1,698/kW
Operation and Maint. Cost	$69/kW/yr.	$115/kW/yr.
Operating Life	30 years	30 years

Assuming investor-owned utility development, the straight-spine SEA Clam would produce energy at a cost of about 77 cents per kilowatt-hour in levelized nominal dollars.

Cost estimates for the circular-spine SEA Clam design were not available at the time the EPRI SEA Clam estimates were prepared. Scale model tests and subsequent cost estimates have indicated that the cost of energy from a 1- to 2-megawatt circular SEA Clam would be about half that of a straight-spine design (Hagerman and Heller, 1988). It is not known to what extent this reduction would apply to SEA Clams scaled to North Pacific Coast wave conditions.

A recent assessment of wave power potential jointly sponsored by Virginia Power and the North Carolina Alternative Energy Corporation (Hagerman and Heller, 1989) indicated that the Gotaverkin Hose Pump may be able to produce electric energy at costs considerably less than the cost of production from a circular SEA Clam. The hose pump has a further advantage for North Pacific applications in that unlike the SEA Clam, the physical size of the device, and hence the amount of materials and fabrication per unit capacity is less sensitive to the longer wave lengths of the North Pacific.

Cost estimates for the Gotaverkin Hose Pump, taken from Hagerman and Heller, were adjusted to make them more comparable with the SEA Clam costs appearing in Table 8-40.[30] The resulting costs and plant characteristics are shown in the right-hand column of Table 8-40. Assuming investor-owned utility

30./ Costs from Hagerman and Heller, 1988, Table 3 (Baltic Sea Hose Pump) were escalated to 1988 dollars using the Gross National Product deflator. To these costs were added the cost of power transmission to shore (omitted from Hagerman and Heller) using costs from EPRI, 1986, and the 10-percent additional contingency used by EPRI.

development, this plant would produce energy at a cost of about 16 cents per kilowatt-hour in levelized nominal dollars.

Conclusions: Wave Power

The most promising of the oceanic energy resources for the Pacific Northwest appears to be ocean wave energy. The Pacific Northwest wave climate is the most energetic of any of the contiguous United States and is within the range of wave power levels considered suitable for wave energy development. Estimated energy costs for offshore devices are, at the lower end of their range of uncertainty, close to the Council's current long-term marginal resource cost. Shore-mounted wave energy conversion devices are the most mature technologies available for wave energy power generation, having been demonstrated at the commercial scale. But, because of land use conflicts and aesthetic impacts, suitable sites for shore-mounted devices are likely to be few in the Pacific Northwest. Off-shore (floating) wave energy conversion systems hold more promise for widespread application in the Pacific Northwest, but this technology has not advanced beyond the scale model testing stage. Widespread commercial deployment of wave power devices in the Pacific Northwest would require these preconditions: development and testing of prototypes for operation under North Pacific conditions, demonstration of a commercial-scale project, and detailed resource and economic feasibility assessments. Prospects for rapid advancement of offshore wave energy technology are diminished by low levels of private and government research support.

Marine Biomass Fuels

Methane (the principal component of natural gas) can be produced by biogasification of carbohydrates derived from marine vegetation. Bio-derived methane could be used to power gas turbines, internal combustion engines or boiler-steam turbines for electric power generation. Cultivation of marine vegetation as an energy source may be more promising than cultivation of terrestrial vegetation for this purpose because of potentially greater yields per unit area and the availability of a currently unused environment. Some federally sponsored research on cultivation of marine vegetation for energy production was conducted through the early 1980s.

Marine Biomass Production Technology

Various species of single-cell and multicellular algae have been suggested for cultivation for their energy potential. Controlled cultivation would provide optimal growing conditions, facilitate harvest and minimize environmental impacts. Research suggests that an open-ocean site may present an optimal environment for cultivation of one promising organism, the giant brown kelp *Macrocystis pyrifera*. *Macrocystis* could be grown on moored near-surface structures. Wind- or wave-powered pumps would pump water from depths of several hundred feet to supply nutrients for maximum yield. (North, 1981; Ryther, 1979/80.) Some concepts envision coupling marine bioculture with ocean thermal energy conversion (OTEC) power plants to take advantage of the artificial upwelling of nutrients created by these plants. OTEC power plants, however, are not feasible in the Northwest. Other proposals would use sewage as a source of nutrients.

Dr. Howard Wilcox, of the San Diego Naval Undersea Center, has proposed cultivating giant brown kelp on arrays of submerged racks (Constans, 1979). The kelp would be harvested periodically, chopped and fed to anaerobic digestors. Cellulose contained in the kelp would be converted into methane at the rate of 400 cubic meters of methane per ton of organic matter.

Cultivation of marine biomass may provide a way of converting the intermittent solar resource into a firm energy supply. Seasonal fluctuations (summer peaks) might remain.

Marine Biomass Fuel Production Issues

Methane production using marine biomass may be technically feasible in the Pacific Northwest. The technology is at a conceptual stage of development, but there appear to be no insurmountable technical obstacles.

Preliminary estimates of the cost of producing methane from marine biomass suggest that this product might be competitive with natural gas if natural gas prices increase as forecast. However, cost estimates for methane production from marine biomass are very preliminary, and the applicability of these estimates to the Northwest is unknown.

Ecological and aesthetic impacts might arise from large-scale conversion of protected marine waters to biomass cultivation. However, open ocean sites appear to offer better prospects for development because of nutrient availability. Adverse water quality and ecosystem effects could result from the introduction of nutrients into marine waters. Near-shore sites could be integrated with tertiary sewage treatment, reducing nutrient load in near-shore waters.

A significant constraint to development of marine biomass-to-energy concepts is the present lack of research support.

Marine Biomass Resource Potential in the Pacific Northwest

No information was located regarding marine bioculture for energy production in the Pacific Northwest. The Northwest marine environment is cold, and winter solar radiation is limited, possibly reducing production potential. However, Northwest waters are rich in nutrients, possibly offsetting temperature and solar radiation limitations.

Cost of Marine Biomass Fuels

Dr. Wilcox estimated that his approach could produce methane at costs ranging from $0.08 to $0.25 per cubic meter. This is equivalent to $4.10 to $12.80 per million Btu[31] in 1988 dollars. For comparison, the cost of firm contract natural gas is forecast by the Council to range from $3.61 per million Btu in 1988 to $5.20 per million Btu in 2007 (in 1988 dollars).

Conclusions: Marine Biomass

Cultivation and gasification of marine biomass for production of methane may have application in the Pacific Northwest. Because only very preliminary studies of this resource have been made (none in the Pacific Northwest), the applicability and cost-effectiveness of this concept in the region are very uncertain. It is unlikely that methane from ocean biomass will be economically competitive with natural gas for many years.

Salinity Gradient Power

Energy is released when fresh and saline water are mixed. Conceptually, some of this energy could be recovered and used to generate electricity. This would be accomplished using salinity gradient energy recovery systems located near the mouths of streams discharging to the sea. Several salinity gradient energy conversion systems have been proposed, but none has advanced beyond the conceptual stage. Although the theoretical resource potential in the Pacific Northwest is substantial, much research, development and demonstration would be required to bring any one of these methods to commercial availability.

Salinity Gradient Power Technology

Concepts that have been advanced for extraction of salinity gradient energy include osmotic hydroturbines; dilytic batteries; vapor pressure turbines and polymeric salinity gradient engines.

Osmotic hydroturbines would use the pressure developed across a membrane, exposed to saline water on one side and fresh water on the other, to drive a hydropower turbine. A proposed design by Reali, illustrated in Figure 8-34, would consist of a fresh water diversion near the mouth of a stream, with a penstock leading to a submarine hydropower turbine located at a depth of about 360 feet. Fresh water would discharge through the turbine into a low-pressure receiving tank. The receiving tank would be emptied continuously by "pumping" the fresh water into the surrounding seawater by means of an osmotic pressure gradient created across semipermeable membranes separating the fresh and saline water.

31./ Btu (British Thermal Unit) is the amount of heat required to raise one pound of water one degree Fahrenheit.

Osmotic Hydropower Plant

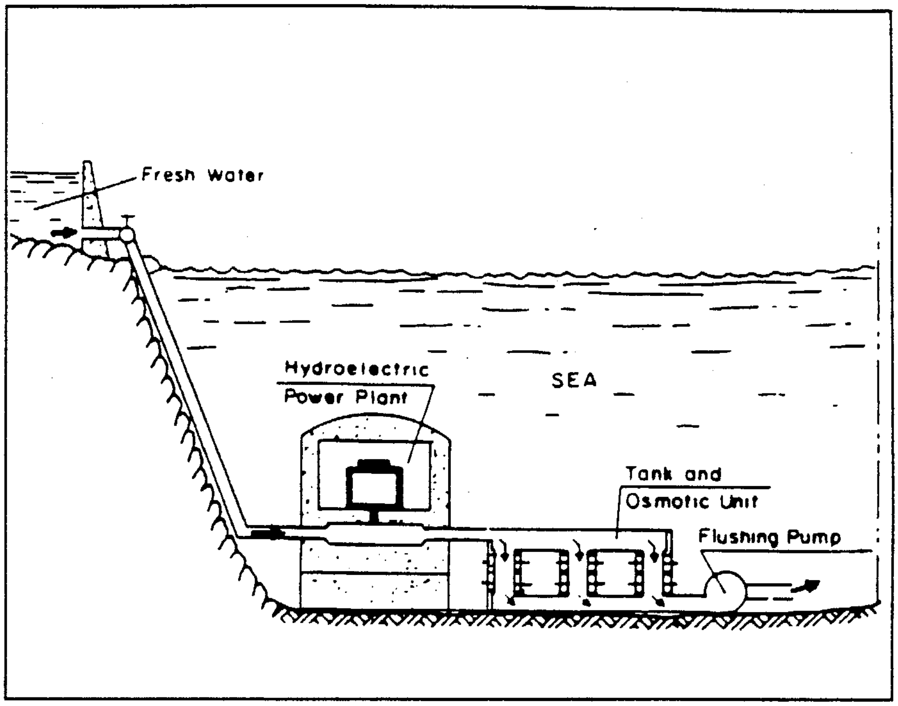


Figure 8–34
Reali Submarine Osmotic Hydropower Plant (EPRI 1986)

Dilytic batteries would use fresh and saline water as the electrochemical agents in a battery. Fresh and saline water would be separated by an ion exchange membrane. An electrical potential would be created across electrodes immersed in the two liquids.

Vapor pressure devices would use the slight difference in vapor pressure of saline and fresh water at equal temperatures to drive an ultra-low-pressure vapor turbine.

Finally, certain polymers when immersed expand and contract with changes in salinity. Materials such as these could be mechanically coupled to a generator.

The potential energy conversion efficiency of salinity gradient power plants is relatively high (an estimated 50 percent for the Reali osmotic hydropower turbine). These devices would produce firm power, seasonally variable due to river flow.

Salinity Gradient Power Development Issues

The large quantities of freshwater discharging to seawater in the Pacific Northwest may provide a significant energy resource that could be recovered using salinity gradient energy conversion equipment. But salinity gradient energy conversion technology has not progressed beyond the conceptual stage, and substantial research, development and demonstration would be required to bring any of the proposed technologies to fruition. Fundamental developments, particularly in membrane technology, would be required for several of the proposed concepts. Only then could the engineering challenges posed by these concepts be addressed.

Furthermore, it is not clear whether natural salinity gradients would be adequate to operate a salinity gradient power plant. If concentrated brines are required to operate these devices, the technology may be feasible only in regions where a sunny coastal climate permits use of evaporation ponds to produce concentrated brine from seawater.

Salinity gradient energy conversion concepts are insufficiently developed to permit assessment of environmental effects.

Salinity Gradient Power Potential in the Pacific Northwest

The theoretical salinity gradient energy resource potential in the Pacific Northwest is large. The largest discharge of fresh water to salt water in the Northwest is from the Columbia River. The Columbia River has an average discharge of 7,300 cubic meters per second. The theoretically available power from a typical freshwater/seawater salinity gradient is 2 average megawatts per cubic meter per second of fresh water flow, giving the Columbia discharge a theoretical power potential of 15,000 megawatts. At the 50-percent level of energy recovery forecast for the Reali osmotic turbine, full use of the Columbia's discharge would produce 7,500 average megawatts of electricity. Practical constraints are likely to reduce this potential.

Cost and Performance of Salinity Gradient Power Plants

Because salinity gradient generating technologies have not advanced beyond the conceptual stage, only extremely preliminary estimates are available. The cost of electricity from osmotic turbines has been estimated to be considerably greater than the cost of energy from alternative sources.

Conclusions: Salinity Gradient Power

Technologies for recovery of useful energy from salinity gradients are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between seawater and fresh water. If salinity gradient energy conversion devices could operate on naturally occurring salinity gradients, the Pacific Northwest would have a large potential resource.

Tidal Power

Tidal power plants are hydroelectric plants that use the energy of water drawn up by the tides to generate electric power. Tidal hydroelectric plants are the most mature of the ocean energy technologies discussed in this paper. Several commercial plants are in operation. The largest plant, a 240-megawatt installation at the estuary of the Rance River on the north coast of France, has operated since 1967. A second tidal hydroelectric plant, an 18-megawatt installation at Annapolis Royal, Nova Scotia, came into service in 1984. Small (submegawatt) plants operate in China and in the Soviet Union.

The Earth's tidal power potential is enormous, and tidal hydroelectric plants are a proven and potentially economical technology. But widespread application of tidal hydroelectric generation is constrained by the unusual site characteristics required. The key requirement is a large mean tidal range, preferably 20 feet or more. Tides of this magnitude occur in only a few locations worldwide where geography amplifies the tidal range. In addition, tidal electric plants require a large bay or estuary with a narrow, relatively shallow entrance suitable for construction of a dam. The best North American sites have received extensive study, and include Cook Inlet, Alaska, sites in the upper Bay of Fundy between New Brunswick and Nova Scotia, Cobscook Bay, Maine, and sites in the Gulf of California. With the exception of Annapolis Royal, none has been developed.

Tidal Power Technology

Tidal generating power plants use a variation of conventional hydropower technology. A typical plant consists of a barrage (dam), sluice gates and a powerhouse with low-head hydroturbines. The barrage is constructed across the mouth of a bay or estuary to form a controlled basin. Sluice gates admit water on the flood tide and are closed near high tide when the basin has filled. When the ebbing tide creates sufficient water head between the basin and the sea, water is released from the basin through the turbines to generate electricity.

The design described above produces electricity only on the ebb tide, slightly less than twice a day on the average. The resulting power is firm and predictable, but cyclical. The tidal cycle shifts about an hour per day so power production is only occasionally coincident with peak loads.

Design features such as multiple pools, reversible turbines and pump-storage permit more continuous production of power. These features often do not prove economical.

Tidal Power Development Issues

Development of tidal hydroelectric power in the Pacific Northwest appears to be technically and economically precluded by insufficient mean tidal ranges. Because a tidal hydroelectric power plant employs relatively mature technology, it is unlikely that technological improvements in the foreseeable future will make tidal hydroelectric technology technically feasible or cost-effective in the Pacific Northwest.

The potential environmental impacts of tidal hydroelectric development have been assessed for several sites in Cook Inlet, Alaska, an area having environmental characteristics somewhat similar to the Pacific Northwest. Construction of tidal-hydroelectric plants at the Cook Inlet sites was expected to alter circulation and flow patterns significantly within the controlled basin and in areas outside the barrage. These alterations probably would lead to water quality changes, including concentration of pollutants. Increased siltation within the basin could be expected. Plant construction would change the basin from a high-energy to a low-energy marine environment with consequent ecological and aesthetic effects. Passage of salmonids, plankton, larval shellfish and marine mammals would be restricted.

Tidal Power Potential in the Pacific Northwest

Tidal hydroelectric power plants require a mean tidal range of 20 feet or greater and a bay or estuary of large volume with a relatively narrow and shallow entrance. Mean tidal ranges in the Pacific Northwest are between 4.5 to 10.6 feet, with the greatest mean tides found in bays and inlets of South Puget Sound (see Table 8-42). The best Northwest sites have only slightly more than half the mean tidal range of potentially feasible North American sites. The power production potential of a tidal electric plant is a function of the square of the mean tidal range. Therefore, energy from the best Northwest tides (assuming geographically suitable sites were available) could be expected to cost about three times that of the Half Moon Cove, Maine, proposal (57 cents per kilowatt-hour in levelized and nominal dollars for a Northwest plant).

Cost and Performance of Tidal Power Plants

The cost of tidal electric power plants is site-specific. The cost example in Table 8-41, for a proposed plant at Half Moon Cove, is illustrative only, because no comparable sites exist in the Pacific Northwest.

Table 8-41
Cost and Performance Characteristics
for a 12-Megawatt Tidal Hydroelectric Power Plant
(EPRI, 1986, Escalated to 1988 Dollars)

Type	Tidal Hydroelectric Power Plant
Location	Half Moon Cove, Maine
Mean Tidal Range	18 feet
Rated Capacity	12 MW (net)
Capacity Factor	35.5%
Construction Cost	$3,870/kW
Operation and Maintenance Cost	$17/kW/yr.
Operating Life	30 years

Assuming investor-owned utility development, this plant would produce energy at a cost of about 19 cents per kilowatt-hour in levelized nominal dollars (11 cents per kilowatt-hour in levelized real 1988 dollars).

Conclusions: Tidal Power

Tidal hydroelectric power plants are a proven technology. Pacific Northwest tidal conditions, however, are inadequate to support cost-effective operation of currently available technology. Moreover, technological improvements that could allow use of Pacific Northwest tidal resources for electricity generation do not appear likely in the foreseeable future.

Ocean Current Power

The kinetic energy of flowing water can be extracted by water-current turbines. Water-current turbines, unlike conventional hydropower turbines, operate on principles similar to wind turbines. Water-current turbines could be used to extract energy from both ocean and stream currents, and in fact, much of the interest in water-current turbines stems from possible stream applications.

Water-current turbines were first studied in 1970 as a mechanism for extracting energy from the Florida Current (the Gulf Stream). Subsequently, water-current turbine research has received modest private and federal support. Conceptual designs for both river and marine applications have been proposed and scale models have been tested. A 2-kilowatt unit was briefly demonstrated in Florida in 1985. Proposals have been advanced for a 100-kilowatt and a one megawatt-scale demonstration unit.

Table 8-42
Mean Tidal Range at Various Oregon and Washington Bays, Inlets and Estuaries (feet)

Site	Mean Tidal Range (feet)	Source
Alsea Bay, Oregon	5.8	a
Chetco Bay, Oregon	5.1	a
Coos Bay, Oregon	5.6	b
Coquille Bay, Oregon	5.2	a
Elk River Estuary, Oregon	~ 5	a
Nehalem Bay, Oregon	5.9	a
Nestucca Bay, Oregon	5.8	a
Netarts Bay, Oregon	5.7	a
Pistol River Estuary, Oregon	~ 5	a
Rogue River Estuary, Oregon	4.9	a
Salmon Bay, Oregon	5.8	a
Sand Lake, Oregon	5.7	a
Siletz Bay, Oregon	5.0	a
Siuslaw Bay, Oregon	5.2	a
Sixes River Estuary, Oregon	~ 5	a
Tillamook Bay, Oregon	5.7	a
Umpqua Bay, Oregon	5.1	a
Winchuck River Estuary, Oregon	~ 5	a
Yaquina Bay (Newport), Oregon	6.0	b
Youngs Bay, Oregon	6.7	b
Blind Bay, Shaw Island, Washington	4.5	c
Budd Inlet (Olympia), Washington	10.5	b
Commencement Bay (Tacoma), Washington	8.1	b
Cornet Bay, Whidbey Island, Washington	6.6	c
Drayton Harbor, Washington	5.9	c
Eagle Harbor, Bainbridge Island, Washington	7.8	d
Elliot Bay (Seattle), Washington	7.7	b
Fisherman Bay, Lopez Island, Washington	4.4	c
Gig Harbor, Washington	8.2	d
Grays Harbor (Aberdeen), Washington	7.9	b
Henderson Bay, Washington	9.4	d
Liberty Bay, Washington	8.0	d
Oakland Bay (Shelton), Washington	10.6	d
Penn Cove, Whidbey Island, Washington	7.8	c
Port Gardner (Everett), Washington	7.4	b
Port Ludlow, Washington	6.4	d
Port Townsend, Washington	5.2	b
Quartermaster Harbor, Vashon Island, Washington	8.2	d
Roche Harbor, San Juan Island, Washington	4.4	c
Sinclair Inlet, Washington	8.0	d
The Great Bend (Hood Canal), Washington	8.1	d
West Sound, Orcas Island, Washington	4.5	c
Willapa Bay (South Bend), Washington	7.8	b

a From Percy, et al., 1974.
b From NOAA, 1988.
c From NOAA, 1985a.
d From NOAA, 1985b.

Ocean Current Power Technology

Conceptual water-current turbine designs for marine applications consist of one or more fan-like blade assemblies suspended across the prevailing current. The slowly rotating blades would drive a generator through a mechanical transmission, or would themselves form the rotor of an induction generator. These power plants would be tower mounted, or would be suspended from buoys and tethered to anchors. Vertical-axis (Darrius) designs also have been investigated.

Because the kinetic energy of flowing water is a diffuse energy source, current turbines must be physically large. A typical river current turbine design using 14-foot diameter rotors, would produce 20 kilowatts. One marine design, the Coriolus ducted turbine, would produce 6.6 megawatts from twin contra-rotating blades 300 feet in diameter.

Power is a function of the velocity of the current cubed. The performance of these machines is, therefore, very sensitive to average current velocity. For example, the Heronemus machine, using twin shafts, each carrying two 240-foot blades (see Figure 8-35), would produce 10 megawatts in a 3-knot (5 feet per second) current and 25 megawatts in a 4-knot (7 feet per second) current.

Ocean Current Power Development Issues

Development of ocean current energy in the Pacific Northwest appears to be precluded by the lack of ocean currents having suitable velocities and by lack of proven technology. When ocean-current turbine technology is proven and becomes commercially available, it may be worthwhile to assess the feasibility of using this technology at sites in Puget Sound that have strong tidal currents.

The conceptual ocean-current turbine designs that have been proposed would appear to have few if any significant environmental effects. One possible problem might be impingement of marine organisms on the rotating blades. This technology, however, is not sufficiently mature to permit an assessment of environmental impacts.

Ocean Current Power Potential in the Pacific Northwest

The energy potential of Pacific Northwest oceanic currents is very poor. Interest in oceanic-current turbines has focused on the east coast of Florida. In that area, there is a strong current relatively close to major load centers. The average velocity of the Florida Current at this location is 8.2 feet per second, nearly 5 knots. The oceanic currents of the North Pacific are, in contrast, weak and poorly defined. Surface and near-surface currents along the Oregon and Washington coast flow in a southerly direction in winter at a mean velocity of about 0.4 feet per second. In summer, the direction of flow reverses to a northerly flow of about 0.6 feet per second. Bottom-current velocities are about one-tenth of surface-current velocities. (Barnes, et al., 1972) The potential power production of surface and near-surface oceanic currents in the Pacific Northwest is less than 1 percent of that of the Florida Current.

Water Current Turbine

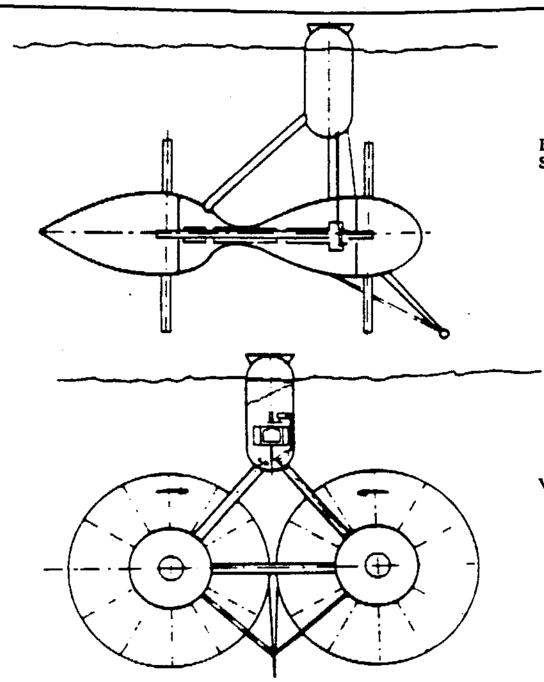


Figure 8–35
Heronemus Water Current Turbine (EPRI 1986)

Mean current velocities of the Strait of Juan de Fuca are less than those of the Oregon and Washington oceanic currents, with average velocities of about 0.1 to 0.2 feet per second. (Barnes, et al., 1972.) But, tidal currents of 3 to 8 knots (5 to 13.5 feet per second) occur locally in Puget Sound and at estuaries and bays along the Oregon and Washington coast (see Table 8-43). These currents are cyclic and attain these velocities for only an hour or two on the run of the tides.

Table 8-43
Tidal Currents at Various
Oregon and Washington Locations (knots)[a]

	Typical	Maximum
Coos Bay, Oregon	2-3	
Agate Passage, Washington		6
Deception Pass, Washington		8
Grays Harbor (Entrance), Washington	1.9-2.8	5
Hammersley Inlet, Washington		5+
Hood Canal, Washington		1.5
Port Washington Narrows, Washington		4+
Point Wilson - Point No Point, Washington	2.7	
Rich Passage, Washington	2.4-3.1	4-5
San Juan Channel, Washington	2.6	
Skagit Bay, Washington	2.0-2.3	
The Narrows, Washington		6
Willapa Bay (Entrance), Washington	2.5	4-6

[a] From NOAA, 1988.

Cost and Performance of Ocean Current Power Plants

Although references to cost estimates for conceptual designs appear in the literature, we have been unable to locate any cost estimates. Because this technology is in its infancy, cost estimates would be highly uncertain and not particularly useful in assessing the potential contribution of this technology to power generation.

Conclusions: Ocean Current Power

Scale models of water current turbines suitable for capturing the energy of oceanic currents have been tested. The oceanic currents of the Pacific Northwest, however, are weak, poorly defined and incapable of powering proposed designs. There may be limited application of water-current turbines in the Northwest for extracting energy from stream currents and from local tidal currents in Puget Sound. Because the latter are cyclical and intermittent (though predictable), the cost-effectiveness of these applications likely would be poor.

Ocean Thermal Gradients

In tropical oceans, the temperature differences between warm surface waters and deeper cold waters are sufficient to drive Rankine cycle heat engines, which can produce electric power. The concept of ocean thermal energy conversion (OTEC) was suggested in 1881 by the French physicist Jacques D'Arsonval. His student, George Claude (inventor of the neon sign), conducted OTEC experiments over a number of years and, in 1926, demonstrated a 60-kilowatt shore-based OTEC power plant at Matanzas Bay, Cuba. Though no net power was produced, the extraction of energy from ocean thermal gradients was demonstrated.

Unsuccessful sporadic attempts to develop OTEC technology were made during the ensuing 40 years. There was renewed interest in the mid-1960s, and in 1972 the U.S. government established an OTEC technology research program. In 1979, Mini-OTEC, a 10-kilowatt (net) barge-mounted unit operated briefly off the coast of Hawaii. This was the first OTEC plant to demonstrate net energy production. Testing of the first megawatt-scale unit, the U.S. Department of Energy OTEC-1, commenced in 1981. This plant operated at its expected efficiency, but experiments lasted only a brief period due to curtailment of federal funding.

Federally sponsored OTEC design work continued, and preliminary engineering of a 40-megawatt Hawaiian plant was completed in 1984, through a federal/state/industry cost-shared contract. Federal funding of all technical development was curtailed, and subsequent federal activity has been limited to basic research on alternative thermodynamic cycles, and cold water intake and heat exchanger designs.

The Japanese have constructed two small OTEC plants. A 100-kilowatt (gross) unit operated briefly on the island of Nauru in 1981. A 50-kilowatt (gross) unit operates on the island of Kyushu. European organizations have evaluated small OTEC plants for tropical locations, and India and Taiwan have investigated OTEC for their own use.

Ocean Thermal Gradient Power Plant Technology

An ocean thermal energy conversion plant extracts energy from the temperature differential between surface waters and waters at depth. Figure 8-36 shows a conceptual layout for a 10-megawatt floating OTEC power plant. While a floating plant is shown, shore-based and platform-mounted designs also might be used. Warm seawater is taken into the powerhouse from the surface layer. Cold seawater is drawn through a suspended intake pipe extending to depths of 2,000 to 3,000 feet. The assembly is tethered to anchors. Power is transmitted to shore via a submarine electrical cable.

OTEC Power Plant

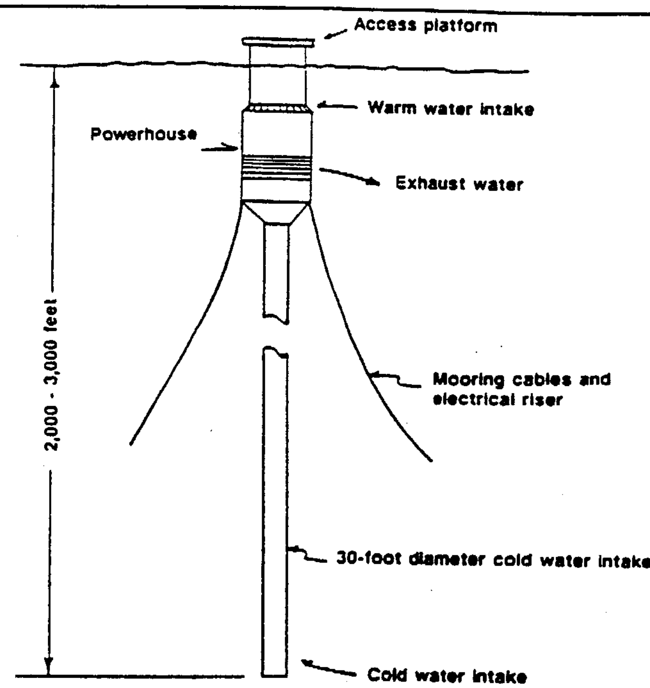


Figure 8–36
Conceptual Layout of a 10–Megawatt Floating OTEC Power Plant (Lennard 1987)

Electricity would be generated in the powerhouse through one of two processes. The open-cycle process (demonstrated by Claude) uses extremely low pressure steam from the vaporization of the warm seawater in a vacuum. This steam would drive large, ultra low-pressure turbine generators and be condensed using the cold water supply. The alternative closed-cycle process (demonstrated by Mini-OTEC) is similar to the binary cycles used to generate electricity from low-temperature geothermal resources. The warm surface water vaporizes a low-boiling-point working fluid such as ammonia or Freon. The vaporized working fluid drives a turbine generator. The working fluid is condensed by the cold seawater and recycled.

Ocean thermal energy conversion plants produce firm power with some seasonal variation. The energy conversion efficiency of these plants, even at the best sites, is very low: 2 to 3 percent. Large components are needed because large quantities of water must be moved.

Important engineering problems must be resolved before these plants achieve sufficient reliability for commercial use.

Ocean Thermal Gradient Power Development Issues

Ocean thermal energy conversion technology is, at present, not technically feasible in the Pacific Northwest because of the small temperature gradients found in North Pacific waters. Because OTEC technology for promising tropical waters is not yet fully developed or demonstrated, it is unlikely that technological improvements in the foreseeable future will allow use of the temperature gradients found off the Northwest coast.

Though the environmental impacts of OTEC power plants are thought to be generally minor, certain factors may be significant. These include the potential release of environmentally hazardous working fluids (ammonia or Freon) used in the closed-cycle system, entrainment of aquatic organisms in seawater circulating systems, displacement of nutrients and organisms via the artificial upwelling created by the plant, and release of antifouling chemicals. Open-cycle OTEC plants would release dissolved carbon dioxide. Experimental data from DOE's Seacoast Test Facility in Hawaii indicate a release rate of about 30 grams of carbon dioxide per kilowatt-hour of generated electricity in a land-based open-cycle OTEC system (Green and Guenther, 1989). However, this is less than 4 percent of the rate of carbon dioxide release from a coal-fired power plant.

Ocean Thermal Gradient Resource Potential in the Pacific Northwest

OTEC power plants require a minimum temperature differential of about 20°C (36°F) to operate. Oceanic temperature differentials of this magnitude are limited to tropical regions, extending to 25 to 30 degrees north and south latitudes. Potential OTEC sites in the United States include the Gulf Coast and Hawaii.

Pacific Northwest coastal waters are characterized by cool surface temperatures. Only limited temperature information is available, but surface highs are reported to average 17°C (63°F) and lows, 7°C (45°F). Temperatures at depth are reported to be 5 to 7°C (41 to 45°F) (Cocke, 1980). This suggests that gradients range from 0 to 12°C (0 to 20°F) with an average of roughly 6°C (11°F). Thus the average temperature gradient in Northwest waters is less than one-third the minimum required by current OTEC technology. Because the thermal efficiency of OTEC plants is a function of the temperature differential, the efficiency of plants operating in Northwest waters would be quite low.

Cost and Performance of Ocean Thermal Gradient Power Plants

Engineering cost estimates have been published for a 40-megawatt shore-based OTEC power plant using closed-cycle technology. This is the design developed in 1984 by Ocean Thermal Corporation under a cost-shared contract with the U.S. Department of Energy and the state of Hawaii. The key cost and performance parameters for this plant are shown in Table 8-44. This plant would use the warm condenser cooling water from an existing conventional power plant to increase the temperature of the warm seawater supply.

Table 8-44
Cost and Performance Characteristics for a 40-Megawatt OTEC Power Plant (EPRI, 1986, Escalated to 1988 Dollars)

Type	Closed-cycle, Shore-based OTEC
Location	Kahe Point, Hawaii
No of Units	1 @ 45.8 MW each
Rated Capacity	45.8 MW (net)
Availability	80%
Capacity Factor	68%
Construction Cost	$12,750/kW
Operation and Maintenance Cost	$195/kW/yr.
Operating Life	30 years

Assuming investor-owned utility development, this plant would produce energy at a cost of about 37 cents per kilowatt-hour in levelized nominal dollars.

Other estimates of the costs of OTEC power plants have ranged as low as $4,000 per kilowatt. At this cost, an OTEC plant could produce energy at a levelized cost of 12 cents per kilowatt-hour. Major engineering problems must be resolved to achieve a reliable commercial OTEC plant. For this reason, current cost estimates are uncertain.

Conclusion: Ocean Thermal Gradient Power

Megawatt-scale ocean thermal energy conversion (OTEC) power plants have been demonstrated, although major technical problems remain. Pacific Northwest ocean thermal gradients are not capable of operating current OTEC power plants. Technological improvements allowing use of Northwest thermal gradients are unlikely.

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Solar

This section reviews solar technologies that produce electricity. Passive and active solar applications are addressed in Volume II, Chapter 7.

The sun's energy must be gathered over a relatively large area and be concentrated if it is to be used as a source of electricity. The key consideration of any solar electric technology is how to gather the energy and convert it to a manageable power source large enough to contribute to a utility power system. This situation is analogous to what we find when considering forest wood residues as a candidate fuel for generating power. The resource exists in relatively large quantities, but it is dispersed over the forest floor, which may make the cost of gathering the wood for energy prohibitive. Once the wood residue is gathered, it is a very reliable resource. This is also true of solar energy. Conversion of the sun's energy to electricity is quite reliable. Solar-electric systems have demonstrated availability factors of over 90 percent.

In addition to the high cost of concentrating the sun's energy, solar's competitive stance in most regions suffers from other shortcomings. It is variable[32] from day-to-day and within the day, it is not available at night and it is seasonal. These characteristics require solar to have storage or a complementary resource if it is to be counted on as a firm resource. In the Northwest, the hydropower system itself could be used in parts of the year as the storage medium for solar-derived energy. In fact, the utility system can be used as both a storage medium and as the backup resource for solar.

The costs of the solar-electric technologies currently are high compared to the costs of alternatives. However, costs are coming down and can be expected to continue to decrease. The performance of photovoltaics is expected to improve also. Currently, Pacific Gas and Electric reports there are 700 separate applications of photovoltaics on their system in remote areas. These are all small applications to power remote lighting or controls. In remote applications such as "island" economies and third-world countries, photovoltaics already are being used to produce electric power. Again, even in Pacific Gas and Electric's service territory, the economics favor on-site photovoltaic power sources with a battery backup compared to extending the distribution system one-half mile or greater.

Manufacturers of photovoltaics, moreover, have developed consumer products from which they expect to profit even as they accelerate research to improve the conversion efficiency of the photovoltaic cells. Remote power needs like electric range fences represent a sizeable market for photovoltaics. Consumer products like solar calculators, watches, yard lights, and a long list of other applications also

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32./ A long record of solar insolation would be valuable, and may be necessary, to be able to predict solar's "critical sun" contribution to the region's electrical system and to plan for the appropriate kinds of resources to complement solar.

represent profitable markets. Thus, it appears that the manufacturers are here to stay and are confident that they will reach conversion efficiency targets that will make photovoltaics competitive with alternative central-station generators. A manifestation of this commitment is the more than $1 billion of private money that has been invested in research to improve solar technologies.

Solar-electric technologies are relatively environmentally benign. The environmental benefits of solar could be the factor that makes solar cost-effective for utility generation much sooner than has been imagined. A recent study of the costs of environmental damage from generating plants has estimated these costs to be as high as the cost of producing the electricity. Should the fears of scientists studying global warming be accepted by decision makers at the national and world level, it is quite likely that solar power, in particular solar photovoltaics, will emerge as one of the preferred alternatives to generate power. This is part of the motivation for the recommended activities related to solar insolation measurement and solar resources listed in Volume II, Chapter 1.

Solar-Electric Technologies

Solar-electric technologies are divided into two broad categories, solar-thermal energy systems and photovoltaics. Each of these two broad categories contains a number of different technologies, all with the same objective of converting solar energy to electricity. Solar-thermal systems are similar to typical generating plants in that heat is converted into electricity via a turbine-generator or other heat engines. Photovoltaics, by contrast, convert the sun's energy to electricity without moving parts by using the electrical properties of the semi-conductor materials used in the construction of photovoltaic cells. The various technologies are discussed in detail below.

Solar-Thermal Plants

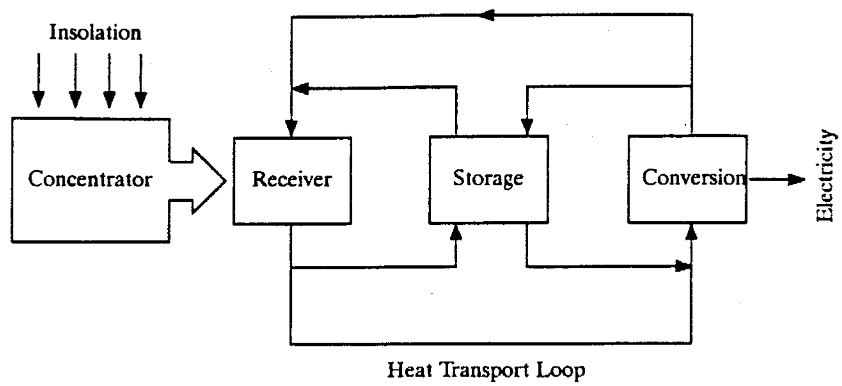
Although solar-thermal technologies are quite different in their particulars, all solar thermal technologies have similar characteristics. Each of the technologies has solar collectors, receivers, energy storage facilities and conversion units that convert the sun's energy to steam and then to electricity. This is shown in Figure 8-37.

The challenge for solar-thermal plants is to collect and concentrate the fuel. Therefore, concentrating collectors are used in solar-thermal systems. The collectors are characterized by large surface area, in order to capture an adequate amount of the total resource, and by geometric shapes that allow them to focus (concentrate) the energy to a smaller receiver. This receiver converts the solar energy to heat. The heat can be stored for later use or used immediately, as in conventional power plants, to produce electricity.

Solar Thermal System

Figure 8–37
Schematic Diagram of Typical Solar Thermal System (with Heat Storage)

Source: *National Solar Thermal Technology Program: Five-Year Research and Development Plan 1986–1990.* U.S. Department of Energy, Office of Conservation and Renewable Energy, September 1986.



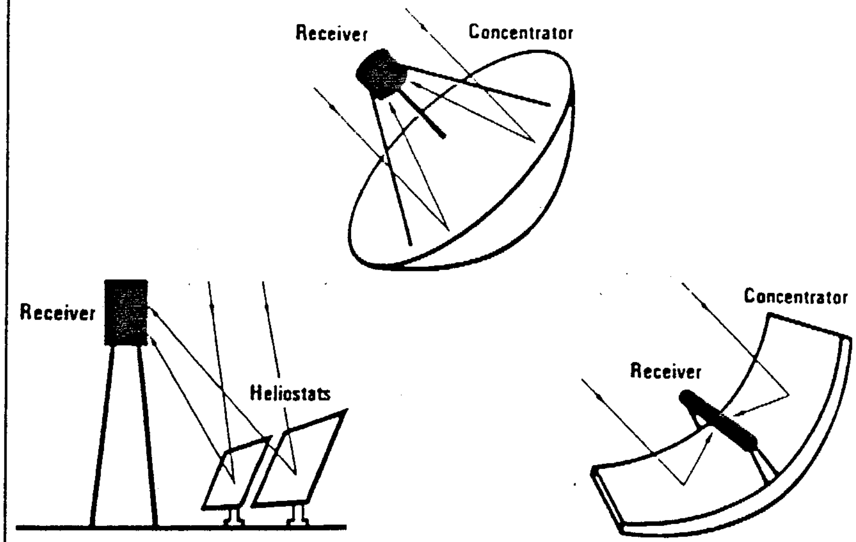
There are three major solar-thermal electric technologies. These are central-receivers, line-focus parabolic troughs and point-focus parabolic dishes. These are depicted in Figure 8-38.

Central Receivers

Central receivers are, as the name implies, technologies with a fixed central receiver. In this technology, the concentrating collector is made up of flat plate heliostats (essentially moveable mirrors), that track the sun and reflect the collected energy to a receiver mounted on a central tower.

A 10-megawatt capacity central receiver successfully operated for several years near Barstow, California. The unit had 1,818 individual tracking heliostats with 766,000 square feet of reflective area. About 30 percent of the heliostats actually face north to capture summer sun that rises and sets, respectively, to the northeast and northwest of the plant. Through August 1986, the maximum annual energy production was 8,816 megawatt-hours, about a 10 percent capacity factor. Peak instantaneous output was 11.7 megawatts.

Solar Thermal Technologies



Central Receiver | Parabolic Dish | Parabolic Trough

Figure 8-38
Solar Thermal Technologies

Source: *National Solar Thermal Technology Program: Five-Year Research and Development Plan 1986–1990.* U.S. Department of Energy, Office of Conservation and Renewable Energy, September 1986.

Parabolic Troughs

The parabolic trough solar-thermal technology is the technology seeing greatest commercial use. This technology is less efficient at higher temperatures[33] than other competing technologies, but the collectors and receivers are simple to make, giving troughs a considerable cost advantage over other solar-thermal technologies, at present. The concentrating collector is a reflective trough bent to a parabolic shape that focuses the sun's energy on an in-line (parallel to the trough) receiver. Troughs typically are situated in a north-south direction and lie horizontal. The troughs are rotated about the long axis to capture as much of the sun's energy as possible. This configuration tends to result in the best trade off between maximizing capacity and keeping first costs and operating and maintenance costs down. However, if the objective is to maximize energy instead of capacity, other orientations might be better. Also, depending on the latitude, construction and operating costs, it might be more efficient to tilt the north- south oriented troughs toward the sun.

33./ Because the receiver is in-line instead of at a point, the parabolic in-line trough does not concentrate as much of the sun's energy as technologies using point-focus receivers. Also, because the area of the receiver is larger, there is more heat lost from the receiver itself.

The receiver in the in-line parabolic trough is a specially coated pipe inside of a glass vacuum tube. The heat transfer fluid contained in the pipes, in the Luz design, is a synthetic oil that is heated to 735 degrees Fahrenheit and passed through a heat exchanger to create superheated steam for the turbine generator.[34] Luz International, the leader in this field, employs a supplemental natural gas system to maintain continuous operation during periods of high demand. This practice is similar to using gas-fired generators to supplement the Northwest's hydropower system.[35] In California, the plants are constrained by state law to produce no more than 25 percent of their total output using natural gas.[36] This constraint results in about 70 percent of the plant's output coming from solar energy.

Luz is currently operating the world's seven largest solar-thermal plants. They represent about 90 percent of the solar electricity being produced in the world (see Table 8-45). All are of the parabolic trough design. In California, Luz is operating 200 megawatts of plant capacity for Southern California Edison. Luz has signed contracts with Southern California Edison for an additional 380 megawatts of capacity to be online by 1994.

It is informative to consider the history of the construction of the Luz design and its performance. Luz refers to its systems as Solar Electric Generating Stations or SEGS, of which 12 have been assigned names (see Table 8-45).

34./ *Luz in Brief*. Luz International Limited, September 1989.

35./ Although the Luz plants are used in California to supply capacity, they could be used as baseloaded plants. If they were, gas backup of solar would be conceptually similar to gas backup of nonfirm hydro.

36./ California has adopted the Federal Energy Regulatory Commission requirement that qualifying renewable resources under Section 200 of Public Utilities Regulatory Commission are constrained to deliver a maximum of 25 percent of power with non-renewable fuels.

Table 8-45
Luz Solar-Electric Generating Stations

	Capacity (MW)	First Cost ($/kW)	Collector Area (sq. mt.)	Annual Energy (MWh)	Capacity Factor (%)	In-Service Date
SEGS I	13.8	4,500	82,960	30,100	25%	1984
SEGS II	30	3,200	165,000	80,500	31%	1985
SEGS III	30	3,620	230,300	91,311	35%	1986
SEGS IV	30	3,760	230,300	91,311	35%	1987
SEGS V	30	4,020	233,120	92,553	35%	1988
SEGS VI	30	N/A	188,000	91,356	35%	1989
SEGS VII	30	3,870	194,280	92,646	35%	1990-1994
SEGS VIII	80	2,788	464,000	252,700[a]	36%	1993-1994
SEGS IX-XII	300[b]					
SEGS XIII	80[c]					

a Estimates.
b Under construction.
c Negotiating with San Diego Gas and Electric, which has been ordered by the California Public Utilities Commission to enter into a contract with Luz for an 80-megawatt facility.

All of the SEGS units but SEGS I are enhanced with the ability to use gas to raise steam for the steam turbine. This enables the units to provide power to the grid throughout the peak needs, from 7 a.m. to 10 p.m. Conversion efficiency of solar insolation to electricity has improved from 29 percent to about 37 percent. For natural gas to electricity the conversion efficiency is about 37 to 38 percent.

Luz anticipates that SEGS VIII will produce electricity at 7 to 8 cents per kilowatt-hour. If this is true, the Luz plants should be economically competitive with many generating alternatives. If the price of natural gas increases, the cost of electricity from the Luz plants will increase. It will not, however, increase as rapidly as electricity from a combustion turbine or a combined-cycle combustion-turbine fired exclusively with natural gas, because the proportion of energy produced using gas is smaller.

Luz has raised over $1 billion of private capital to develop its technology. SEGS VIII through XII alone represent an investment of $1.2 billion. These facts manifest the confidence of investors in line-focus parabolic troughs as a resource that can be relied on to produce reliable power, given an adequate solar resource.

Point-Focus Parabolic Dish

As shown in Figure 8-38, the concentrator collector of a point-focus parabolic dish looks somewhat like the inside of an umbrella. Ideally, each point on the surface should reflect a beam of light to the same point in three-dimensional space, the focal point, which is where the receiver is located. To accomplish this, the collector has to be pointed directly at the sun at all times, requiring an accurate two-axis tracking system.

The receiver of a point-focus parabolic dish is placed at the focal point. Some parabolic dish designs link the receivers directly to an individual engine-generator using steam or other heat transfer fluid. Alternatively, the heat transfer fluid can be piped to a central heat exchanger to produce steam to run a turbine generator, as in the line-focus parabolic trough system.

Construction of the parabolic dish has been difficult, because of the difficulty in bonding high quality reflectors to the inside face of the dish and because of the difficulty in forming the materials into the precise geometric shape needed to optimize the concentration of solar energy. In addition, very accurate tracking devices are required, which is not the case for the line-focus parabolic trough. If the problems with this technology are solved, it could be a major source of solar-generated electricity because the technology can produce higher temperatures and therefore greater thermal efficiencies than other solar thermal technologies. However, the costs of parabolic dish designs are very high.

There were four field experiments being conducted as of May 1987 using parabolic dishes.[37] These are:

<u>The Solar Total Energy Project</u>

This project is located in Shenandoah, Georgia and includes 114 parabolic dishes having reflective surfaces of 4,352 square meters. The concentrator collectors and receiver produce 750°F fluid that is piped to a central steam generator. Electricity, process steam, and air conditioning are produced by the system.

<u>Solar Plant I</u>

This privately financed project is located in Warner Springs, California. The concentrator collectors and the receivers are variants of the typical dish design, but the system to convert heat to electric energy is similar to the Solar Total Energy Project. The peak capacity of the system is 4.9 megawatts.

<u>Osage City, Kansas</u>

This project contains an engine connected directly to each receiver. The design uses an organic Rankine cycle[38] The system has a total field capacity of 100 kilowatts.

37./ For more detailed information on these, see *Power from the Sun: Principles of High Temperature Solar Thermal Technology*. Solar Energy Research Institute, May 1987 (SERI, 1987).

38./ Rankine-cycle device is a type of heat engine that is a thermodynamic device to convert thermal energy to work. The working fluid is usually steam, but other fluids can be used. An organic Rankine cycle engine uses an organic liquid such as toluene as the working fluid.

Molokai, Hawaii

This project has a capacity rating of 250 kilowatts. The receivers supply steam to individual reciprocating steam engine-generators alongside each receiver.

Solar Photovoltaic Technologies

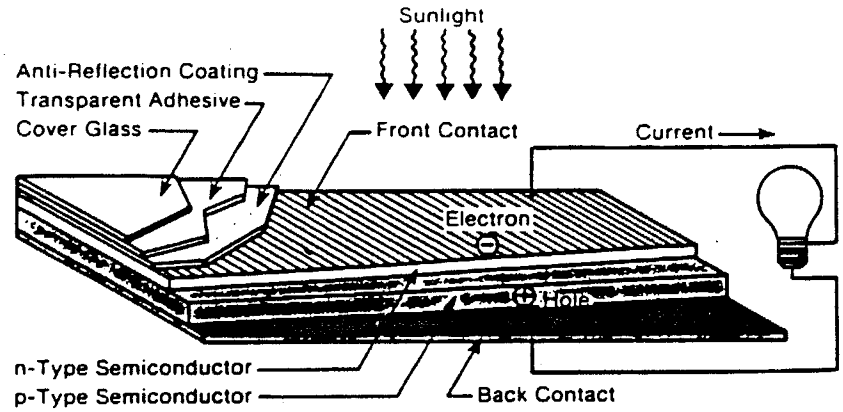
Photovoltaic cells are solid-state electronic devices that produce electricity with no moving parts. There are two broad categories of photovoltaics, flat-plate and concentrating. Flat-plate photovoltaics typically are employed as stationary panels but also can be used with tracking devices. Designs using concentrating cells track the sun throughout the day and use lenses to intensify the sun's energy on the cells. Concentrating cells use only the direct-beam radiation coming from the sun. Flat-plate photovoltaics use both direct-beam and diffuse solar energy.

Photoelectric cells convert solar energy into direct current electricity by absorbing light from the sun. The absorption process frees electrons to carry a direct current. The direct current from all cells is then converted to alternating current for use in standard grid-connected electric systems. Solar photovoltaics are a proven technology, and photovoltaics have many uses in today's markets.

The typical solar cell is a flat-plate cell made from a thin (less than 0.5 millimeters thick) wafer of silicon crystal. Its size is about 100 square centimeters and it produces about one watt of power (see Figure 8-39). Cells can be grouped into modules, and modules can be grouped into arrays to provide as much power as needed. The direct current is put through a power conditioner containing an invertor if it is to be converted to alternating current.

Crystalline Silicon Cell

Figure 8–39
Typical
Photovoltaic Cell



Thin-film solar photovoltaic cells made of amorphous-silicon many times thinner than the silicon crystal wafers and 10 times thinner than a human hair are being developed by several manufacturers. Although the amorphous-silicon cells convert sunlight to electricity less efficiently than do the silicon-crystal cells, their lower cost makes them a strong candidate to be the first photovoltaic technology to become competitive as central-station utility power plants. The lower costs of thin-film cells result from using less material than crystal-silicon cells and from using low-cost laser technology to lay down the electrical conductors of the cells. In addition, thin-film cells can be made in much larger sheets than can other cells. Because there are no wires, the expected lifetime of the amorphous-silicon cells is thought to be longer than that of single crystalline cells.

Initially, thin-film cells using amorphous-silicon can convert about 6 to 7 percent of the sun's energy falling on them to electricity, but the cells degrade to an equilibrium level of about 4 to 5 percent efficiency. Laboratory tests have achieved efficiency levels of about 12 percent. In order to be cost-competitive with other central-station generation alternatives, the industry estimates that it will have to improve conversion efficiencies to about 15 percent. If this goal is reached, it would reduce production costs to about $1 per peak watt for the cells and about $4 per peak watt (including profit) installed on the utility grid. At this price, the industry believes the technology will have applications on utility grids. Utility-scale orders will enable manufacturers to produce the quantities required to lower costs further.

Research is proceeding on multiple layer thin-film cells, which have theoretical efficiencies as high as 42 percent. The concept employed in multiple layered (stacked) thin-film cells is the use of materials in successive layers, each absorbing a different part of the solar spectrum. The layering allows for more of the sun's energy to be gathered and converted to electricity. In the laboratory, stacked thin-film cells have achieved 13.5 percent efficiency. An additional advantage of stacked thin-film cells is that they do not degrade as quickly or as much as amorphous-silicon thin-film cells.

Concentrator-photovoltaic technology intensifies the solar energy by employing a tracking system to follow the sun. Lenses are used to focus and intensify the sunlight on the photovoltaic cells. Concentrator photovoltaic cells using single silicon-crystal material have achieved efficiencies of 26 percent. Industry experts, however, believe that it will take much longer for the cost of the concentrator-photovoltaic cells to be competitive with conventional generating resources than it will for the other photovoltaic technologies.

At the present time, photovoltaics cannot compete economically with other solar technologies or other electricity generating technologies at the scale required to make major contributions to utility systems. However, photovoltaics are used to produce electricity in remote applications, island communities, and in consumer products, such as watches and calculators. A recent application has photovoltaic modules installed as sun roofs on automobiles to trickle-charge the battery and to run an exhaust fan while the car is parked in the sun. The exhaust fan lowers the temperature in cars parked in the sun and should enable auto manufacturers to down-size air conditioners.

These consumer applications are mentioned only to show that the technology is a proven way to produce electricity from the sun. Much developmental work remains to be done before photovoltaics become economical for utility power plants. However, the progress to date has been dramatic, and projected improvement targets are to lower the cost to 8.5 cents per kilowatt-hour by 2010. At that price, photovoltaics clearly will be cost-competitive with other sources of electricity. Figure 8-40 shows the progress of photovoltaics from 1982 to 1987, the last year for which documented data are available. Prices have dropped, efficiencies have improved, and lifetimes and stability have been increased. The Boeing Company recently announced a new gallium arsenide concentrator cell that converts 37 percent of the sun's energy into electricity.

Photovoltaic Progress

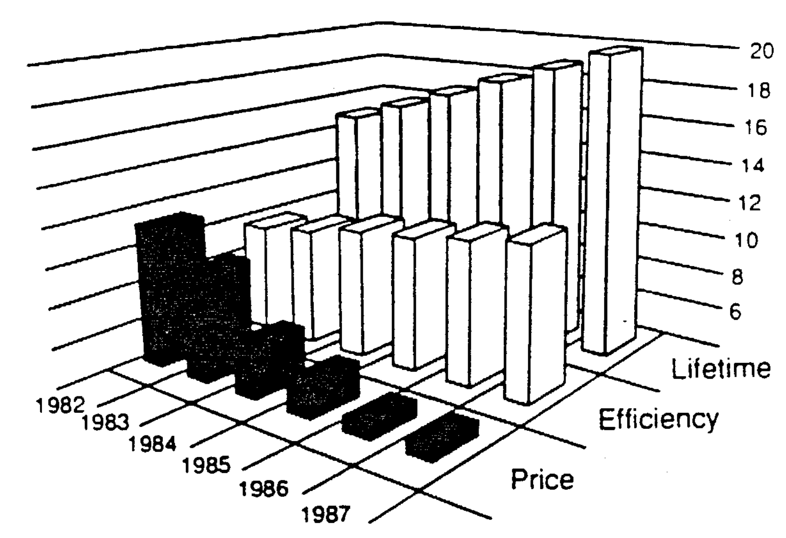


Figure 8–40
Solar Photovoltaic Progress (1982–1987)

Development Issues

Principal issues associated with the large-scale development of solar power in the Northwest are cost, solar resource data, site availability, electric power transmission and power quality.

Cost

Although costs have continued to decline, power generation using solar-electric technologies remains considerably more expensive than alternatives (although there are specialized applications for which photovoltaics are cost-effective). Because the most cost-effective solar-electric technology at present is the Luz-type parabolic trough technology, this technology can be used as an index of the cost of solar compared with other resources. The cost of energy from parabolic trough solar technology in the Northwest is estimated below.

Solar Insolation Data

As with hydropower, a long and continuous data record is desirable in order to accurately assess the potential of solar resources. This is not surprising because the availability of both hydropower and solar resources is determined by climate and weather, which can vary from year to year. This variation can be seen by examining past annual measurements of solar at Whitehorse Ranch in Southeastern Oregon and at Maynard, Massachusetts. Measurements of annual beam solar radiation taken in 1981 at Whitehorse Ranch were 15 percent greater than the same measurement taken in 1982. Over the nine years of measurements taken at Maynard, Massachusetts, the difference between the highest measured year and the lowest was 18 percent, with a variance of about 6 percent.[39] These two examples of variation imply that solar is less variable then either hydropower or wind. However, variations could be greater in specific locales, and average differences of 10 percent or so could mean the difference between a site and technology combination being cost-effective or not.

Although there have been several data collection activities in the past, the existing regional irradiation data base is not deemed to be adequate for a long-term assessment of the region's solar potential. However, many solar experts in the region believe that this region could have a first-rate solar data base with a modest, continuing level of effort.

Site Availability

Specific sites have not been identified for solar-thermal plants, but they would most likely be located where the solar resource is the best. In this region that would include eastern Oregon and southern Idaho. One of the best solar resource areas available anywhere is in northeastern Nevada, reasonably close to the region's grid. Should solar-thermal electric generating stations become cost-effective, it is likely they would be sited in these areas. The good news is that there would be plenty of land available. The bad news is that a plant in that location would experience energy and capacity losses if its power was transmitted to the major load centers west of the Cascades.

Photovoltaic facilities can be sited anywhere, although they also perform better in sunny areas. But because they use both direct-beam and diffuse sunlight, they will operate in any part of the region. One of the nice features of photovoltaics is that they can be sited on buildings, where they would not use any land or have significant distribution and transmission losses.

Electric Power Transmission

Transmission cost for solar-thermal electric plants could be high if plants are sited far from the grid and major regional loads. Transmission lines are both difficult to site and expensive to construct. Locations near the existing grid, which appear to exist, will lower these costs.

Specialized applications of photovoltaics have few transmission constraints because typically they are sited near the loads they are serving. If photovoltaics develop to the point that central-station plants become cost-effective, this technology also could run into transmission siting and cost constraints.

39./ *Pacific Northwest Solar Radiation Data.* Solar Monitoring Lab, Physics Department - Solar Energy Center, University of Oregon. April 1, 1987.

Power Quality

Because solar energy is an intermittent and seasonally variable resource, the value of power from solar-electric plants may be less than from alternative resources. Because it is intermittently available, the energy produced by solar plants must be either used when generated or stored for later use. Though the Northwest hydropower system has some energy storage capability, it is unclear at this time how much solar-produced energy can be stored without conflict with other water uses. This problem is compounded for solar energy because the resource is at its minimum in winter, when regional loads are at their greatest and demands on the hydropower system are most severe.

Environmental Effects

Solar potentially is one of the most environmentally benign forms of energy production. In fact, this perception of solar is a prime reason for its popularity. The major environmental concerns about solar-electric generation are water use (solar-thermal), potential release of toxic materials, land use and aesthetic impacts. Possible air quality effects would have to be considered if supplemental gas firing were to be used for solar-thermal systems.

Water Impacts

Solar-thermal power plants are heat engines and therefore require water for condenser cooling. Solar-thermal plant efficiencies are similar to, or less than fossil-fueled power plants and therefore require similar or slightly more water for comparable power production. Other water uses are small, e.g., water for heliostat cleaning. Water impacts can be mitigated by use of closed-cycle cooling systems and, in areas of water scarcity, by use of dry cooling systems.

Release of Toxic Materials

Heat exchange and storage fluids for solar-thermal power plants include sodium, organic oils and molten salts. Normal operation will result in very modest release; however, accidents could cause significant release of such material. Containment of such releases if they occur must be considered in the design of systems using toxic fluids. Some newer designs, for example, the future Luz parabolic trough plants are expected to use water as the heat transfer medium.

The primary photovoltaic material is silicon, the primary component of sand and, therefore, of no concern environmentally. Because some of the materials used in advanced photovoltaic cell designs include components of arsenic and cadmium, there may be cause for concern about their release in the environment should their use become widespread. This concern is more applicable to manufacturing and disposal of photovoltaic devices than to the application of photovoltaics because these materials are contained within intact cells.

Land Use

A typical 100-megawatt central-receiver plant designed for rated output under average daily direct solar radiation in southeastern Oregon or southwestern Idaho (approximately 18 mega-joules, per square meter, per day), would require approximately 300 acres of collector surface (3 acres per megawatt capacity). Assuming approximately one-third of the plant site is occupied by collector surface, then approximately 1,000 acres would be required for this plant (18 acres per megawatt).

The lower conversion efficiency of photovoltaic systems leads to somewhat greater unit area requirement for collectors (7.5 acres per megawatt). Because fixed arrays are used with photovoltaic systems, closer spacing of collector surfaces may be possible. However, because of the need for land for power conditioning equipment, we will again assume approximately three times the collector area is required for the total station. This gives a total land area for a 10-megawatt station of approximately 150 acres (15 acres per megawatt). To the extent that photovoltaics are placed on roofs and walls of buildings, the land use question is of lesser concern.

The availability of land in the Northwest should not be a problem. There may not be land available near specific load centers; however, the superior solar resource sites generally are in remote areas with abundant undeveloped land (see Figure 8-44 on page 8-221).

Aesthetics

Solar-electric plants might result in major aesthetic intrusions in desert areas favored for plant siting. These areas are currently generally unmarred by man's activities.

Fish and Wildlife

Overall land requirements for solar thermal and solar photovoltaic systems are in the same general range as the land requirements for other energy system. The effects upon terrestrial habitat may, however, be very different than the effects of, for example, the buffer zone around a reactor. It is likely that the value of the station site as wildlife habitat would be essentially eliminated because areas not directly pre-empted by the "footprints" of collector supporting structures and other plant equipment likely would be maintained in a vegetation-free condition to facilitate access to, and minimize interference with, collector surfaces and other plant equipment. Effects on overall biological productivity, however, are likely to be small, given the generally low productivity of the desert sites likely to be selected for solar power developments.

Water may be an environmental constraint for solar-thermal stations in sunny, dry areas where such plants are expected to be sited, unless dry cooling towers are used. Use of water in arid regions may impact fish and aquatic ecosystems. Photovoltaic cells require no cooling or other consumptive use of water. In general, effects on water quality and fish and aquatic ecosystems are likely to be negligible compared to conventional thermal plants.

Prospects for the Development of Solar-Electric Resources in the Pacific Northwest

Several definitions will help in understanding the discussion of the resource potential. The rate of energy falling on the earth's surface is referred to as insolation. It is typically measured in watts per square meter. The direct rays from the sun are referred to as beam radiation, and the portion of beam radiation that falls on a surface (e.g., a collector) installed normal (perpendicular) to the sun's rays is called beam-normal radiation. Part of the beam radiation is diffused in the atmosphere and is reflected from surrounding terrain. This radiation is referred to as diffuse radiation. The cumulative amount of solar energy over a unit of time is referred to as irradiation.

Solar Resources of the Pacific Northwest

Table 8-46 lists past solar data collection activities in the Northwest. Figure 8-41 shows the regional location of the data that have been collected. Prior to 1977, the region had little quality data. Beginning in 1977, the National Oceanic and Atmospheric Administration installed equipment at Boise, Seattle-Tacoma, Medford and Great Falls to measure both the diffuse and direct-beam insolation. Also in 1977, Bonneville and the Eugene Water and Electric Board contracted with the University of Oregon to collect data at nine sites in the region, six of which collected both diffuse and direct insolation. Others, as indicated in Table 8-46, were also collecting solar data. Few sites have been monitored long enough for an accurate estimate of the potential for solar in the region. Many of these efforts have been discontinued. In this plan, the Council is calling for expanded and continuing collection and refinement of solar insolation data.

Nationally, the National Weather Service has collected data on beam-normal irradiation, although most solar researchers believe the data base to be inadequate for estimating the long-term potential for solar at a given site. Efforts are underway to improve the data base and collection protocols. Most national researchers rely on the Typical Meteorological Year data base, also used by conservation analysts to estimate energy use by buildings in diverse locations. This data base covers 248 sites over the past 25 years. However, adequate data was only collected from 27 sites and was estimated for the other 221 sites using statistical techniques. The data base is available from the National Oceanic and Atmospheric Administration.

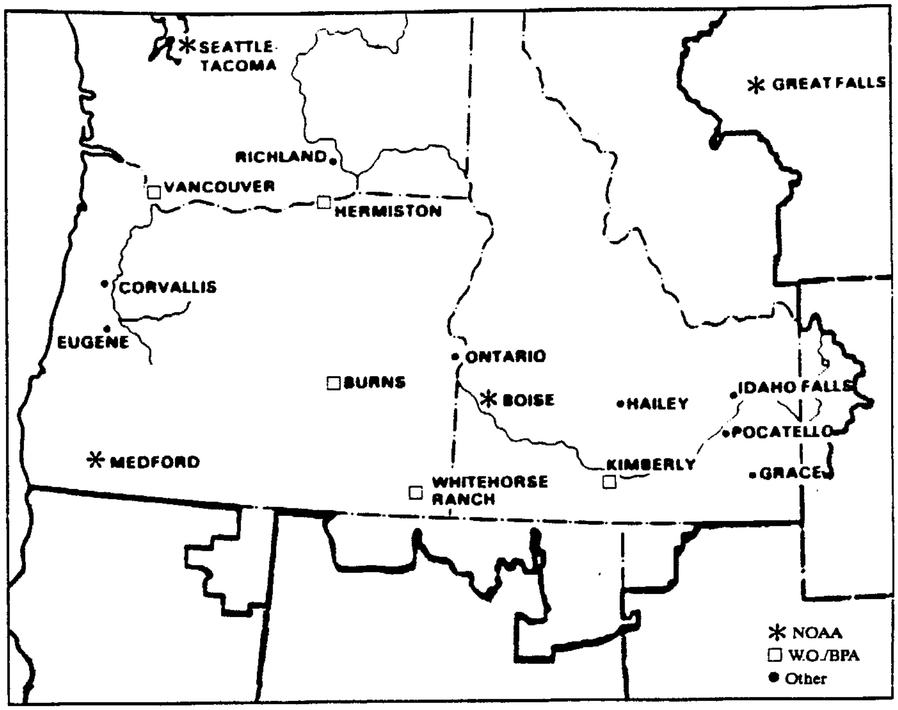
Table 8-46
Northwest Solar Insolation Data Collection Sites

Site Location	Responsibility	Type of Data: Global	Direct	Diffuse	Spectral
Boise, Idaho	NOAA	X	X		
Burns, Idaho	BPA/UO	X	X		
Corvallis, Oregon	DOE/OSU	X	X		
Coeur d'Alene, Idaho	WWP/UO	X	X		
Eugene, Oregon	EWEB/UO	X	X		
Grace, Idaho	Utah P&L/USU	X		X	
Great Falls, Montana	NOAA	X	X		
Hailey, Idaho	INEL	X	X		
Hermiston, Oregon	BPA/UO	X	X		
Hood River, Oregon	PP&L/UO	X	X		
Idaho Falls, Idaho	INEL	X	X		
Kimberly, Idaho	BPA/UO	X	X		
Medford, Oregon	NOAA	X	X		
Ontario, Oregon	TRW	X	X		
Pocatello, Idaho	INEL	X	X		
Richland, Washington	PNL	X	X	X	X
Seattle, Washington	NOAA	X	X	X	
Vancouver, Washington	BPA/UO	X	X		
Whitehorse Ranch, Oregon	BPA/UO	X	X		

Legend:
- BPA/UO - Bonneville Power Administration/University of Oregon
- DOE/OSU - U.S. Department of Energy/Oregon State University
- EWEB/UO - Eugene Water and Electric Board/University of Oregon
- INEL - Idaho National Engineering Laboratory
- NOAA - National Oceanic and Atmospheric Administration
- PNL - Pacific Northwest Laboratory (Battelle)
- PP&L - Pacific Power and Light
- WWP - Washington Water Power
- USU - Utah State University

Insolation Monitoring Sites

Figure 8–41
Current Insolation Data Monitoring Sites with Direct Normal or Equivalent Measurements



Contour maps of solar irradiation have been developed based on extrapolation and interpolation of data collected by the National Weather Service. These maps are shown in Figures 8-42 and 8-43. Figure 8-42 shows values on a flat surface facing south and tilted by a number of degrees equal to the latitude of the site. Figure 8-43 shows irradiation on a horizontal surface. The contour lines of constant irradiation levels, shown in mega-joules[40] per square meter per day, are rough approximations of actual data, and are not suitable for detailed solar generating resource assessment. Local pockets of solar may be missed. For example, though irradiation levels in the Olympic rain shadows have been shown to be much higher than surrounding areas of western Washington, this local effect does not show on Figures 8-42 or 8-43.

In general, the better sites in the region, southeastern Oregon and southern Idaho, receive about 80 percent of the insolation received in Phoenix, Arizona and about 75 percent of that received in Barstow, California, the site of the Solar One solar thermal power facility (Solar Monitoring Laboratory, 1985). By comparison, Eugene receives about 47 percent and 52 percent of the insolation received in Barstow and Phoenix, respectively. An examination of Figures 8-42 and 8-43 reveals that southern Idaho and southeastern Oregon have extremely good solar resources.

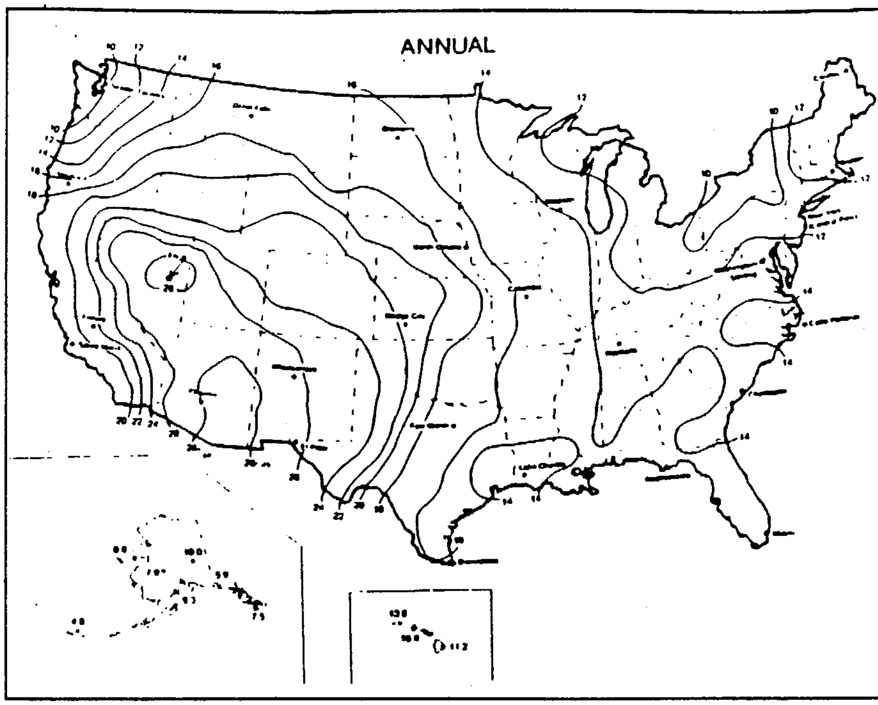
Figure 8-44 shows the more promising areas for solar in the region, based solely on the estimated amount of irradiation.

40./ One mega-joule is equal to 0.28 kilowatt-hours.

Total Daily Solar Radiation

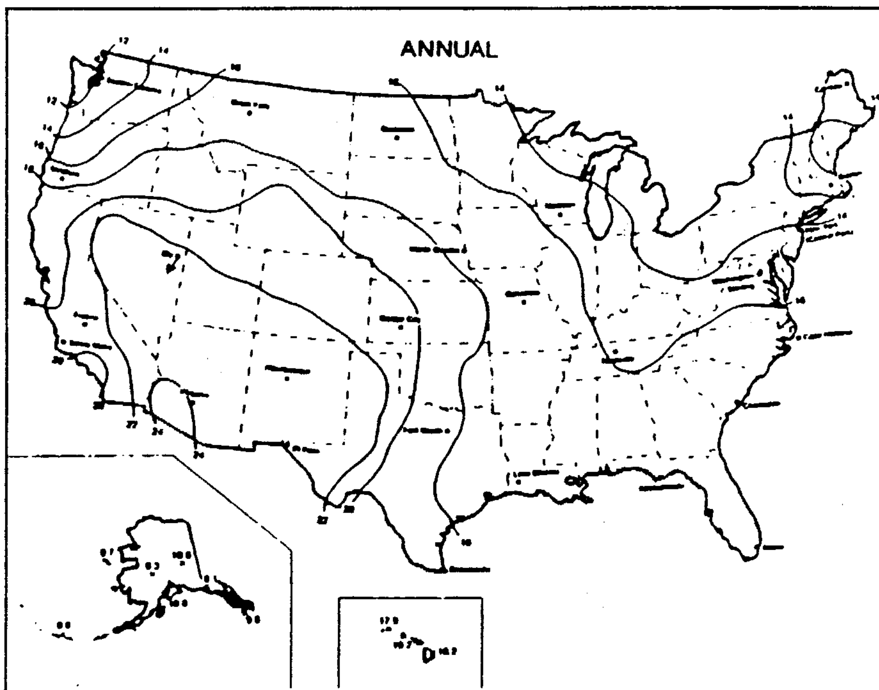
Figure 8–42
Average Daily Total Solar Radiation on a South Facing Surface, Tilt = Latitude (MJ/M2) (Solar Radiation Resource Atlas of the United States 1981)

Source: Draft Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest: Volume IX, Solar. Battelle Pacific Northwest under contract to the Northwest Power Planning Council, June 1982. Figure 7.1, Page 7.2.



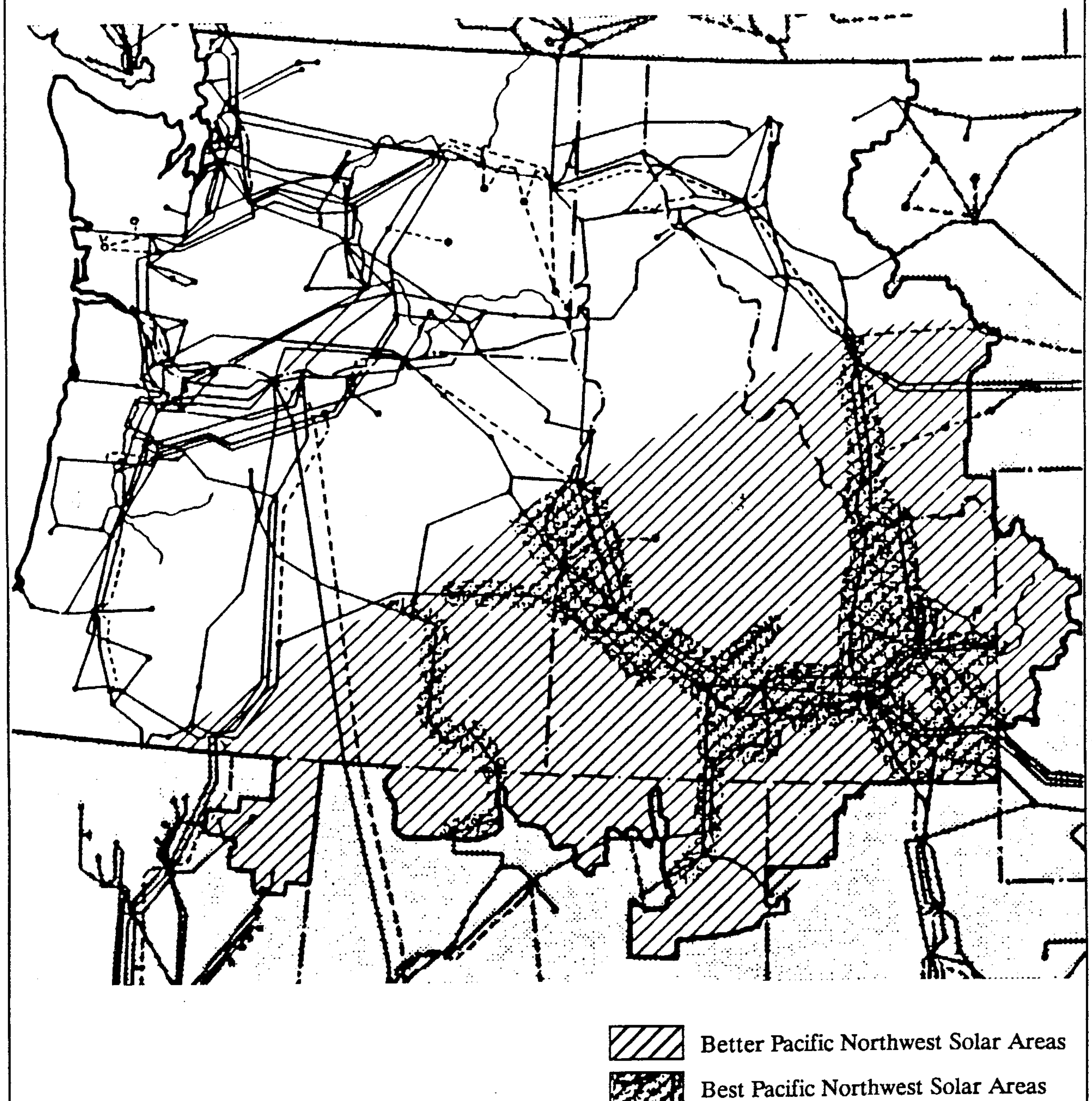
Daily Direct Solar Radiation

Figure 8–43
Average Daily Direct Normal Solar Radiation (MJ/M2) (Solar Radiation Resource Atlas of the United States 1981)



Central Solar Plant Sites

Figure 8-44
Promising Areas in the Pacific Northwest for Central Solar Generating Plants



Costs and Performance of Solar-Thermal Power Plants

All solar technologies face the same challenge in lowering costs. To a much larger extent than most technologies, solar performance is affected by its own geometric requirements, the clearness of the ambient air, and the direction from which its fuel comes. The trade offs to be made between efficiency and costs in designing solar plants are numerous. There are seemingly many more trade offs than in designing conventional plants. For example, a principal objective of all solar technologies is to collect as much solar energy as possible and concentrate it to as high a temperature as possible, subject to the capability of materials to handle the heat, while maintaining acceptable costs. The operating objectives would be met, in part, by always tracking the sun's path, and concentrating the collected energy to as small a receiver as possible to achieve higher temperatures and to lower heat loss from the receiver. (Increasing the receiver temperature increases the conversion efficiency of the plant, other factors being equal.) However, it is interesting to note that the solar technology that is producing 90 percent of the world's solar electric energy, the Luz in-line parabolic trough, does not track the sun's path precisely and uses an in-line receiver, which does not allow for as much concentration of the energy as other receivers. The reason, of course, is that it costs money to build a technology to the optimal performance level, and today those costs can not be recovered with the additional energy that would be gained.

The good news about solar-thermal is that there seems to be a technology embodying solar energy that can compete in some utility service territories today. The better news is that if the cost of achieving more optimal designs is lowered, other thermal solar technologies will be competitive, and possibly will produce lower-cost electricity than the parabolic troughs.

In any case, all research, for all technologies, is aimed at improving components with similar functions. These research aims are:

1. Increasing the effective collector area relative to the size of the receiver. This can be done by changing the size ratio of the collector and receiver components or by more accurately tracking the sun's path, so that the sun remains parallel to a line from the collector center to the receiver.

2. Improving the quality and lowering the costs of the reflective area of the collector surface. This requires lowering the construction cost of highly polished and accurate surfaces, which to date have been hard to mass produce, with the possible exception of the parabolic trough.

3. Improving the absorptive characteristics of the receivers.

4. Finding low-cost ways to maintain reflective characteristics of collectors through better materials and cleaning techniques and to lower the amount of particulate matter in the ambient air between the collector and the receiver.

Because the technology is in place and operating, this assessment of costs will concentrate on the parabolic trough with supplemental gas-firing technology. Current costs and future cost targets for parabolic troughs without gas enhancement, central receivers and parabolic dishes will be cited from existing literature.

Gas-Enhanced Parabolic Troughs

The overnight capital cost of parabolic troughs with gas enhancement is about $2,100 per kilowatt. The portion of the costs represented by the parabolic trough assemblies reportedly has declined by a factor of 4 to 6 since the first unit was installed in 1984. Levelized nominal costs of energy have dropped from 25 cents per kilowatt-hour in 1984 to about 11 cents per kilowatt-hour today and are expected to be 7 to 8 cents per kilowatt-hour for the plants now under construction. It is important to remember that those cost figures are for a plant located in the desert southwest where there is an excellent solar resource and the developer has intimate knowledge of the local resource.

There are many good solar resource areas in the region that are located near existing transmission lines. This can be confirmed by looking back at Figure 8-44, which has superimposed on it the regional transmission grid. However, depending on the plant location, there could be additional costs to connect to the utility transmission system. The cost of a 115 kilovolt transmission line, which is adequate to transport electricity from a 150-megawatt power plant, is about $110,000 per mile. For a 30-megawatt plant producing 210,000 megawatt-hours at an 80 percent capacity factor, the transmission requirement would add 0.07 mills per kilowatt-hour per mile to the levelized cost of energy. Each 20-mile segment would add 1.4 mills per kilowatt-hour to the levelized cost. Larger plants would see proportionately lower costs per kilowatt-hour; a 150-megawatt plant would see an increase of about 0.3 mills per kilowatt-hour per 20 mile segment. Thus, even at relatively long distances from a transmission system, the incremental cost would be small compared to the cost of power.

As an independent check on the costs of gas-enhanced parabolic troughs, staff has estimated the cost of a gas-fired steam turbine[41] operating at a 10 percent capacity factor, which is consistent with 30 percent of the output of the plants coming from gas-fired electricity. That portion of the cost is about 16.5 cents per kilowatt-hour nominal levelized 1990 dollars. Given today's costs reported to be at about 11 cents per kilowatt-hour, this would imply that the costs of the 70 percent share contributed by solar would be about 8.6 cents per kilowatt-hour. Assuming nominal levelized operating costs of about 1.5 cents per kilowatt-hour for the solar energy, that leaves 7 cents per kilowatt-hour for the solar plant, exclusive of the turbine-generator, which already has been counted in the 16.5 cents per kilowatt-hour cost for the gas-fired portion of costs. The solar portion of energy is 65,100 megawatt-hours per year, representing an annual cost of 7 cents per kilowatt-hour or $4.6 million. Using the Council's discount rate of 8.15 percent implies a per-kilowatt cost of $1,686. Adding $1,686 to the $550 for the steam turbine results in $2,240 per kilowatt. This estimate is close to the estimates given by the Luz company.

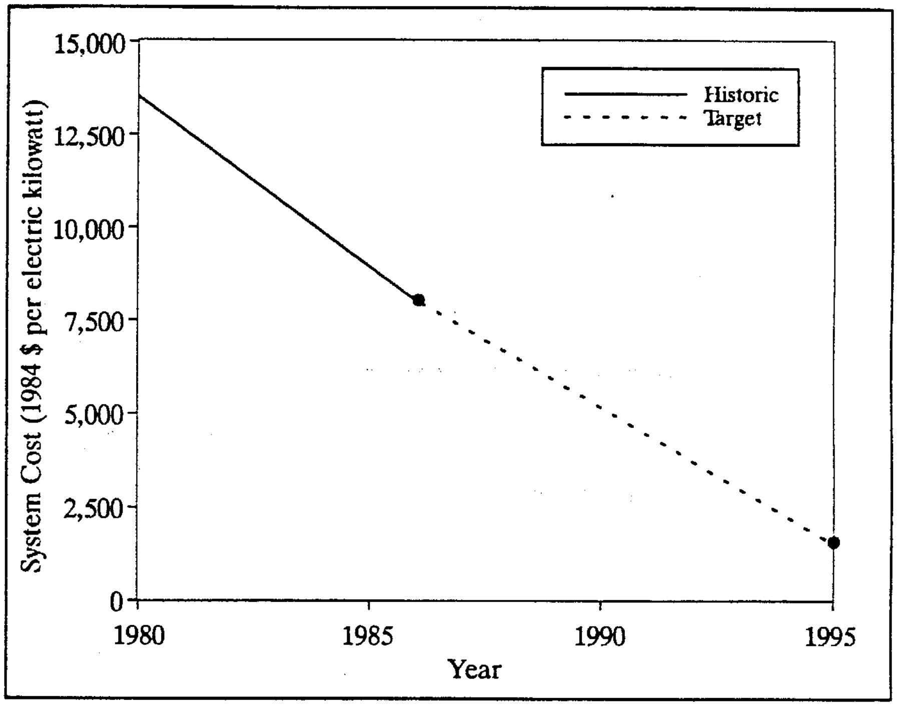
41./ For the purpose of this calculation, costs of an aero-derivative gas combustion turbine, assumed to be $550 per kilowatt, was used as a proxy.

Parabolic Dishes

Cost for parabolic dishes also have dropped rapidly over the last decade. Figure 8-45 shows parabolic dish capital costs from 1980 through 1986 and future target costs. Costs have dropped from $13,500 per kilowatt in 1980 to near $8,000 per kilowatt at present. The target costs show a decline in the figure to $1,500 per kilowatt by 1995. The information in Figure 8-45 was produced three years ago. Costs have not decreased as quickly as was projected for this technology, and there have been difficulties encountered with the engine-generators used at the focal point of each dish.

Parabolic Dish Cost

Figure 8–45
Cost Trends and Targets for Parabolic Dishes (Focal–Point Engines)



Central-Receiver Systems

Costs for central-receiver systems dropped from the $15,000 per kilowatt for the Barstow Solar One project to about $3,000 to $4,000 per kilowatt by 1986. Costs are projected to decrease further to a level of $1,500 per kilowatt by 1995 to 2000. This appears to be a difficult target to achieve.

The Council will follow the progress of central-station solar-electric systems over the next several years to determine whether the Northwest should take any action regarding solar central-station systems. These actions could include detailed assessments, pilot projects, shared research, development and demonstration, and so forth.

Photovoltaics

Photovoltaics did not come on the scene until 1954 when they were invented by Bell Laboratories. In the 1960s and 1970s they were used almost exclusively to power space satellites. At that time, solar cells cost about $500 per peak watt (a watt produced at solar noon). By 1980, this cost had dropped to $50 per peak watt and today solar cells are being produced for $5 per peak watt. The industry target is $1 per peak watt by the early 1990s. The primary reason for the expected cost reduction is the advent of computer-controlled, large-scale production lines. When profits and installation costs are added, the cost would be about $4 per peak watt or about $4,000 per kilowatt of capacity. By the late 1990s, the industry expects to be competitive with utility-scale generating plants.

Figures 8-46 and 8-47 show electricity cost goals for photovoltaic technology in cents per kilowatt-hour (nominal dollars) for a range of assumptions related to various component costs.[42] Figure 8-46 assumes a balance of system cost related to cell area of $50 per square meter and a balance of system cost related to power production of $150 per square meter. Figure 8-47 is based on the same underlying assumptions as Figure 8-46, except that balance of system cost related to cell area is $100 per square meter. Costs are shown for four different assumptions about module efficiency in converting solar energy to electricity. The shaded areas represent national targets for the year 2000.[43] At those prices, given the environmental advantages of solar, photovoltaic electricity almost certainly would be competitive.

42./ Costs were calculated based on the fundamental solar equations for photovoltaics. The formulae can be found in the U.S. Department of Energy's, *Five Year Research Plan, 1987-1991: National Photovoltaics Plan.* Financial assumptions used by the Council for other resources were used also in the calculations shown in Figures 8-46 and 8-47.

43./ The targets are for efficiency levels and costs and do not imply specific values for module costs or balance-of-system costs.

Photovoltaic Flat Plate Cost

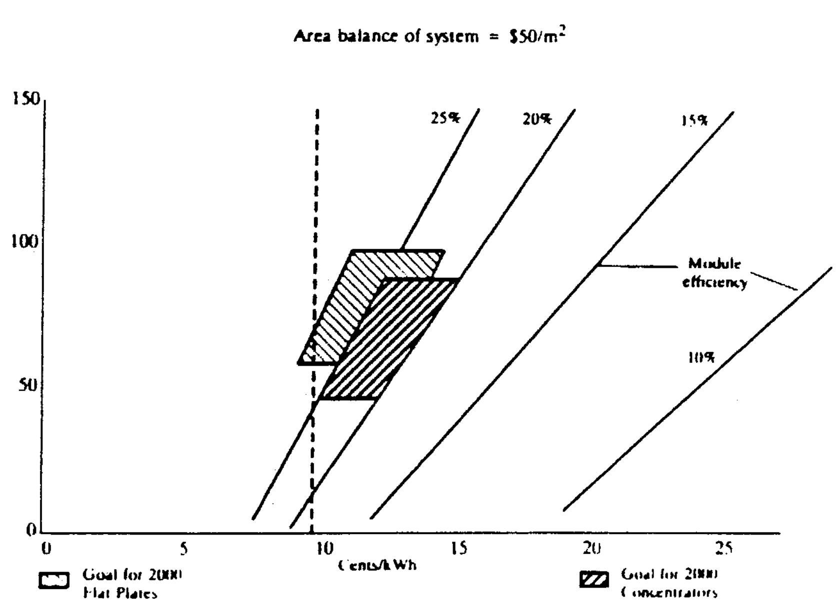


Figure 8–46
Flat Plate Photovoltaic: Current Costs and Goals

Photovoltaic Flat Plate Cost

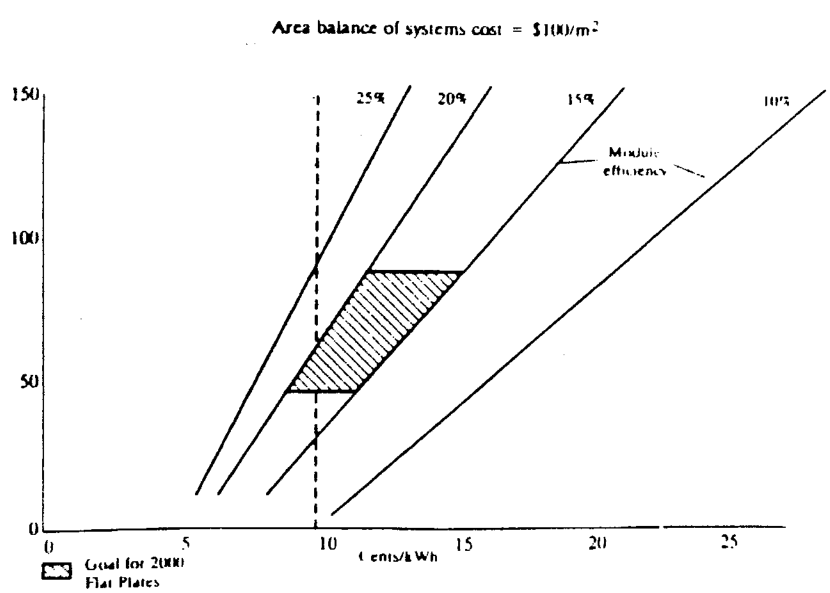


Figure 8–47
Concentrator Photovoltaic: Current Costs and Goals

Cost of Energy from Solar Technologies

Currently high capital costs for solar-thermal plants make them too expensive for the Northwest as stand-alone resources. However, the use of such a plant in conjunction with a combined-cycle combustion-turbine was thought to have some merit. In this concept, a parabolic-trough solar-electric plant would share certain equipment with a combined-cycle combustion-turbine plant. This would reduce the capital cost of the parabolic trough plant, thereby improving its cost-effectiveness. This arrangement, if technically feasible, appears to constitute the least-cost solar-electric technology. Therefore, it can serve as an index of the economic competitiveness of central-station solar-electric technologies in the Northwest.

Conceptually, the plant would consist of a combined-cycle combustion-turbine power plant, similar to that described in Appendix 8-A. An advanced parabolic trough solar collector and receiver, using water as the heat transfer fluid, would provide an alternative steam supply to the steam-turbine generator of the combined-cycle plant. The steam turbine, condenser, condenser cooling system, generator and switchyard would be shared between the plants. Note that such a plant has not been constructed, and the technical feasibility of the combination is not known. (For example, the steam conditions from the parabolic trough array may be inadequate for the steam section of the combined-cycle plant, and supplemental heating may be required.)

The parabolic trough array would supply steam for operation of the steam section of the combined-cycle plant whenever two conditions were met: 1) the combined-cycle plant is displaced (i.e., not operating) because of the availability of nonfirm hydropower; and 2) sufficient solar energy were available to support operation of the steam section of the combined-cycle plant. It also appears economical to use the output of the solar array to operate the steam section of the combined-cycle plant during periods of hydro deficit (i.e., to use the solar plant to backup nonfirm hydropower) as long as the solar-powered output of the steam plant is adequate to meet nonfirm hydropower backup requirements. If the solar output were inadequate, the combined-cycle plant would be shifted to gas-firing, and the steam section would be operated with combustion turbine exhaust heat. The precise extent to which the solar plant could provide useful power would require analysis of the complex relationship of nonfirm availability, solar power availability, gas price and the technical and economic characteristics of the combined-cycle plant.

The Council performed a preliminary analysis of the cost of this hybrid plant. The estimated cost and performance characteristics of several parabolic trough configurations are shown in Table 8-47. For this analysis, the incremental costs of a parabolic trough array (column 3 of Table 8-47) were added to an expected future regional system containing several gas-fired combined-cycle plants. The incremental levelized life-cycle cost of 450 megawatts of parabolic trough capacity (126 average megawatts of energy from solar) run in conjunction with a combined-cycle combustion-turbine is on the order of 14 cents per kilowatt-hour. This cost increases as solar capacity is added.

Table 8-47
Cost and Performance Characteristics of Representative Solar-Electric Power Plants (1988 Dollars)

	Parabolic Trough (Stand-alone)	Parabolic Trough (Gas Heater)	Parabolic Trough (w/CCCT)[a]
Plant Configuration	One 80-MW Unit	One 80-MW Unit	One 150-MW Unit
Rated Capacity (MW/unit)	80	80	150
Peak Capacity (MW/unit)	80	80	80
Equivalent Annual Availability (%)			
Dispatchability	Must-run	Dispatchable	Must-run
Capacity Factor (%)	28%	28%	28%
Heat Rate (Btu/kWh)	N/A	n/est	N/A
Siting and Licensing Cost ($/kW)	$14	$15	$12[d]
S&L Hold Cost ($/kW/year)	$3.00	$3.00	$2.00[d]
Construction Cost ($/kW)[b]	$2,875	$2,964	$2,353[d]
Fixed O&M Cost ($/kW/year)	$44.00	$44.00	$6.00[d]
Variable O&M Cost (mills/kWh)	0.8	0.8	3.1[d]
Siting and Licensing Lead Time (months)	24	24	24
Construction Lead Time (months)	12	12	36[c]
Service Life (years)	30	30	40

a Collector/receiver portion of parabolic trough plant only. Plant is assumed to share a turbine/generator with a 420-megawatt combined-cycle combustion-turbine plant.
b "Overnight" costs (excludes interest during construction).
c Construction lead time is controlled by construction of the accompanying combined-cycle combustion turbine.
d Costs are the incremental costs of the solar collector/receiver plant.

Comparing these costs to the costs of electricity from new coal generation, about 8 to 9 cents per kilowatt-hour, clearly indicates that solar is clearly more costly than coal in this region. There are a number of reasons for this. The technology is expensive, even considering just the incremental cost of the parabolic trough array. This expense is compounded by the relatively low capacity factor (approximately 28 percent) expected. Also, in the Northwest, peak solar months occur during the summer, when power needs are low. This tends to lessen the value of a resource that generates the bulk of its energy during the summer months.[44] If the efficiency of the technology improves or capital costs come down, solar plants may become cost competitive in this region.

Conclusions

Solar already is contributing a large amount of power to utility grids in Southern California. The gas-enhanced parabolic trough appears to be a viable resource now in the proper niche where the solar resource is plentiful. Photovoltaics are used widely in remote applications and probably will occur on buildings in the next five to 10 years. The region should identify possible future roles of the resource.

Clearly, solar resources are much farther advanced than they were when the Council adopted its 1983 and 1986 power plans. It is now very important that we refine our regional solar data base, as solar thermal and photovoltaics continue to make rapid progress. We will need an adequate data base to have confidence in our assessment of solar resources operating in concert with existing and planned resources.

Recognizing the potential importance of solar, the Council has called on Bonneville and other utilities in the region to re-establish a regionwide solar insolation monitoring system with continued collection of solar insolation data, and to conduct an analysis of the feasibility of solar applications. In addition, the Council recommends that the region seek out opportunities to demonstrate cost-effective solar technologies.

Solar power can be designed to maximize its contribution to energy or to capacity. Solar alone can not be relied on as a base-loaded plant, unless storage is available to cover daily and seasonal swings in insolation. However, even without storage, solar, at the right costs, could be used in the region. Several ways to employ solar can be considered:

1. One obvious way would be to use a solar resource in combination with a natural gas resource, as in the Luz hybrid design. The gas essentially would back up solar in the same way it is being proposed to back up nonfirm hydropower.

2. The combination of solar and natural gas could be used to firm nonfirm hydropower. Often during cold and dry years, those weather conditions that

44./ See the section on resource cost-effectiveness and seasonal benefits in Volume II, Chapter 10.

stress the hydropower system have a lot of sunshine. If analysis of weather data confirmed this observation, solar might be a very good complement to the hydropower system. It could allow operators to maintain storage levels in the late summer and early fall when stream flows are lowest and recreational demands are highest. Earlier withdrawals from the fisheries water budget could be "paid back" using the high solar production months of summer and fall.

3. A stand-alone solar power plant would be used as a must-run resource. That is, use whatever energy is produced and regulate the output of dispatchable resources.

4. For any part of the region that is summer-peaking and is constrained by inadequate transmission capacity, solar plants could satisfy the resource needs and avoid transmission upgrades.

5. Remote applications of photovoltaics could provide power in lieu of construction or upgrading of transmission and distribution lines.

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System Efficiency Improvements

Technology improvements, improved engineering capability and increasing marginal resource costs create opportunities for increasing the efficiency of the existing regional power system. Opportunities for cost-effective system efficiency improvements often arise during repair or replacement of existing equipment. This section contains analyses of four types of efficiency upgrades that can be implemented on the existing regional power system. These are 1) improvements to the efficiency of existing hydropower plants, 2) improvements to the efficiency of existing thermal power plants, 3) improvements to the efficiency of the transmission and distribution system, and 4) conservation voltage regulation (improved control of distribution system voltage). Efficiency improvements may be secured in each of these areas at generally low cost and with little or no environmental impact.

Hydropower Efficiency Improvements

Hydropower efficiency improvement measures offer the potential for cost-effective increases in capacity and energy from existing regional hydropower projects. This potential is due to improved engineering, materials and equipment that have become available since many of the region's hydroelectric projects were built. Additionally, electrical energy costs, and therefore the cost of electrical losses, are much higher now than when much of the regional hydropower system was designed. Because the cost of losses used for the original designs was lower than if these projects were being designed today, designs and equipment often were chosen that are of lower efficiency than those that would be selected today.

An in-depth assessment of the regional potential for hydropower system efficiency improvements appeared in the 1986 Power Plan. This assessment was based upon the findings of a series of studies, beginning with a 1984 report, prepared by the U.S. Army Corps of Engineers, that assessed ongoing and potential improvements in the efficiency of the Corps' hydropower projects (USACOE, 1984). A 1985 report, prepared by Raymond Kaiser Engineers for Bonneville (BPA, 1985), was the first attempt at a regionwide assessment of savings from hydropower efficiency improvements. That study estimated the costs and energy savings attributable to a variety of efficiency improvement measures applied to a generic 100-megawatt hydropower unit. The generic estimates were augmented by a case study of the 774-megawatt Wells hydropower project. Regionwide estimates were developed by extrapolating generic plant estimates. During preparation of the 1986 plan, the Council, with the assistance of Bonneville, the Pacific Northwest Utilities Conference Committee and regional hydropower operators worked to refine the estimates of hydropower efficiency improvements appearing in the Raymond Kaiser study. The findings of this effort subsequently were published by Bonneville (BPA, 1986).

That work suggested that about 110 megawatts of additional firm energy could be obtained by improvements to the efficiency of existing regional hydropower projects. Although some improvements to the facilities included in that estimate have been implemented, the Council does not believe that the potential for additional improvements has changed significantly since 1986. For this reason, the Council has not undertaken a reassessment of this resource and is assuming that 110 megawatts of energy from hydropower efficiency improvements remains available.

Efficiency Improvement Measures

The principal measures available to improve hydropower project efficiency are the following:

Turbine Improvements

Turbine runners (blade and hub assembly) of improved design and materials, air injection, contour reshaping and seal improvement may improve turbine reliability and efficiency beyond original design specifications, especially for older units. In addition, improvements in the efficiency of turbine operation and design often will reduce the mortality of fish passing through the units.

Turbine Governor Improvements

Many of the region's hydropower projects use turbines of the Kaplan type. The blade angle of a Kaplan turbine is adjustable to improve efficiency as load and water head vary. On early units, the blade angle was controlled by a two-dimensional mechanical cam. As reservoir level fluctuated, cams were to be changed to maintain optimum efficiency. Because of the effort required, these cams typically have been changed only when it is anticipated that the reservoir will be maintained at a constant level for some time. As a result, these turbines often are operated at less than optimum efficiency.

In the early 1970s, a three-dimensional mechanical cam was developed. The three-dimensional cams incorporate the contours of the set of two-dimensional cams in a single cam, eliminating the need to change cams manually. More recently, a microprocessor-based blade control system has been developed in which the relationships between blade angle, gate opening and operating head are electronically programmed.

To maintain optimum performance, a Kaplan turbine should have an "index" test performed that determines the optimal relationship among blade angle, gate opening and operating head. This relationship is unit-specific and varies over the unit life. An advanced microprocessor-based blade control system has been proposed that would provide automatic index testing and update of the electronic cam program. The expected increase in efficiency has been estimated to be from 0.5 percent to 3 percent. A portable index testing unit has been developed by Bonneville. Development and demonstration of governors incorporating automatic index testing is required before the potential of these devices can be assessed.

Generator Windage Loss Reduction

Improvements in the design of generator cooling systems have reduced "windage" losses due to air friction. Retrofit of older generators with improved cooling systems has been demonstrated; however, not all older machines lend themselves to retrofitting. The general feasibility of cooling system retrofits also has been questioned because of interference with access to generator internals. Additional assessment of this measure is required before the cost and availability of potential energy savings can be determined.

Generator Rewinding

Modern conductor insulation is thinner than that available in the past, allowing a greater amount of conducting material to be placed in each stator slot in a generator rewind. This reduces resistance losses and may increase the rated capacity of the machine. To fully use the increased generator capacity, however, turbine improvements also may be required. Additional assessment of this measure is required before the cost and availability of potential energy savings can be determined.

Solid-State Exciters

Solid-state generator exciters feature lower losses and reduced maintenance costs compared to earlier designs. Additional assessment of this measure is required before the cost and availability of potential energy savings can be determined.

High-Efficiency Transformers

Older transformers were selected on the basis of energy costs much lower than those experienced at present, and therefore may be less efficient than designs based on forecast energy costs. The cost and availability of energy savings through replacement of main power transformers have been assessed as part of Bonneville's Customer System Efficiency Improvement study (see Transmission and Distribution Loss Reduction, page 8-237).

Improved Water Use

Some water is lost to turbine operation and may include water used for fishway attraction, navigation lock operation, fish ladders and juvenile fish bypass systems. Bypass water losses cannot be reduced beyond certain practical limits. However, bypass losses can be reduced through improved spillway gate seals, spillway gate position indicators, bypass water energy recovery facilities and other measures.

Increased Operating Head

Increasing the operating head of hydraulic turbines can increase the turbine power output. Turbine modifications and generator rewind may be required to fully use the additional power. Methods available for increasing operating head include raising reservoir levels and reducing head losses due to hydraulic friction. The feasibility of raising reservoir levels is site-specific and requires consideration of the social and environmental effects of the increased pool level, possible impacts on the output of upstream projects due to increase in tailwater levels and the cost of modifying turbine generator units to exploit the increased operating head. The Chief Joseph pool level was raised successfully; conversely, the proposed High Ross project was terminated, largely on environmental grounds. Head losses result from friction in water intakes, canals, penstocks and other water conveyance structures. These losses can be reduced by several means, including enlarging the existing water conveyance structures and constructing parallel structures. These measures generally will appear as hydropower project upgrades on the regional hydropower data base and will be included in the assessment of new hydropower resources.

Reduction in Station-Service Loads

Hydropower station loads may be reduced through typical industrial conservation measures. These include efficient motors, high-efficiency lighting and controls, load balancing, power factor correction, high-efficiency station-service transformers, removal of unnecessary voltage regulators, heating, ventilating and air conditioning (HVAC) improvements, and weatherization. Possible savings from these measures have not been included in the estimates of hydropower efficiency improvements.

Measure Cost

The Council in its 1986 Power Plan assessed the cost of hydropower system-efficiency-improvement measures, using as its principal source the study prepared for Bonneville (BPA, 1985) by Raymond Kaiser engineers. The Bonneville study included estimates of the cost and performance characteristics of each of the hydropower efficiency improvements described above, with the exception of bypass water energy recovery facilities. These are too site-specific to be estimated generically. Cost and performance estimates were based on a representative 100-megawatt capacity hydropower unit.

The estimated costs of these measures have been escalated to 1988 dollars using the Handy-Whitman Index of public utility construction costs. The resulting levelized costs in nominal dollars are shown in Table 8-48. The costs shown in Table 8-48 are based on the incremental costs of implementing these measures. Note, however, that several of the higher-cost measures, such as generator rewind, could be implemented during normal equipment overhaul or replacement, reducing the cost and improving the cost-effectiveness of these measures.

Resource Availability

For the 1986 Power Plan, a joint effort was undertaken involving the Council, Bonneville, PNUCC and regional hydropower operators to prepare an inventory of hydropower units on which the estimate of availability of regional savings could be based. The resulting estimates of regional hydropower efficiency improvements potential are shown in Table 8-48. Turbine runner replacement and installation of electronic governors provide about 110 megawatts of potentially cost-effective improvements and appear to be available for development. To achieve the low costs shown in the table, however, implementation of these measures must be undertaken when overhaul or replacement of the affected components is required. Thus this resource only can be acquired gradually, and operators must be prepared to implement these measures when the opportunities arise.

Because of uncertainties regarding cost and feasibility, the measures shown as "promising" in Table 8-48 are not currently considered available for development.

Conclusion

Energy from potential hydropower efficiency improvements is an attractive resource because of its low cost and generally attractive environmental effects. Improvements in turbine design and operation allowing better operating efficiency may reduce the mortality of fish passing through the turbines. Much of the region's hydropower capacity is controlled by federal agencies, and improvements to these projects are subject to the federal budgeting process. Ways should be explored to encourage the upgrades of federal projects.

Because of the attractive costs and environmental qualities of hydropower efficiency improvements, the Council recommends that hydropower operators secure all cost-effective measures as opportunities arise. Current efforts to secure hydropower efficiency improvements, such as those pursued by the Washington Water Power Company at the company's older facilities, should become the norm regionwide. Regionwide acquisition of this resource will require all hydropower operators, including Bonneville's preference customers, to consider marginal resource prices consistent with the region's avoided cost. Federal hydropower operators, as well, should be encouraged to evaluate plant improvements on the basis of regional avoided cost.

The Council encourages further assessment of the cost and availability of the promising resources identified in Table 8-48. The Council also encourages development and demonstration of advanced technologies leading to further improvements in the efficiency of hydropower units.

Table 8-48
Availability and Cost of Hydropower Efficiency Improvements

	Energy (MWa) Available	Promising	Cost (cents/kWh)[a]
Turbine Runner Upgrades (Kaplan)	--	--	3.1
Turbine Runner Upgrades (Frances)	--	--	1.6
Total Energy, Turbine Runner Upgrades	85		
Electronic Governors	27	--	0.1
Windage Loss Reduction	--	46	1.0
Generator Rewinding	--	5	108.5
Solid-State Excitors	--	9	13.4
High-Efficiency Transformers	--	--	2.1
Improved Water Usage	--	23	0.3[b]
Station-Service: High-Efficiency Motors	--	--	10.0
Station-Service: Improved Powerhouse Lighting	--	--	11.0
Station-Service: Improved Powerhouse HVAC	--	--	74.2
Total Station Service Upgrades		17	

a Reference levelized life-cycle costs, nominal dollars. Based on a hypothetical 1988 in-service date; normalized to a 40-year service life.

b Costs based on representative gate position indicator upgrade.

Thermal Plant Efficiency Improvements

The efficiency of existing thermal plants may be upgraded to an extent depending on age and design. This upgrading may reduce operating costs and increase plant capacity and energy output. The extent of upgrades may range from minor component replacement to complete repowering using advanced design heat sources such as fluidized bed combustors. Major process modifications such as repowering are unlikely to be cost-effective at present because of the contemporary design of most of the region's thermal plants. However, component upgrades typical of industrial conservation efforts, such as efficient motors, variable-speed motor controllers, efficient pumps and efficient lighting, may prove cost-effective.

Because the Council does not have a current assessment of the cost and availability of upgrades to the region's thermal plants, it has not been possible to explicitly include this resource in the resource portfolio. Because of the likely cost and environmental advantages of these upgrades, the Council encourages operators of the region's coal, nuclear and natural gas-fired power plants to aggressively seek out cost-effective improvements to the efficiency of these plants.

Transmission and Distribution Loss Reduction

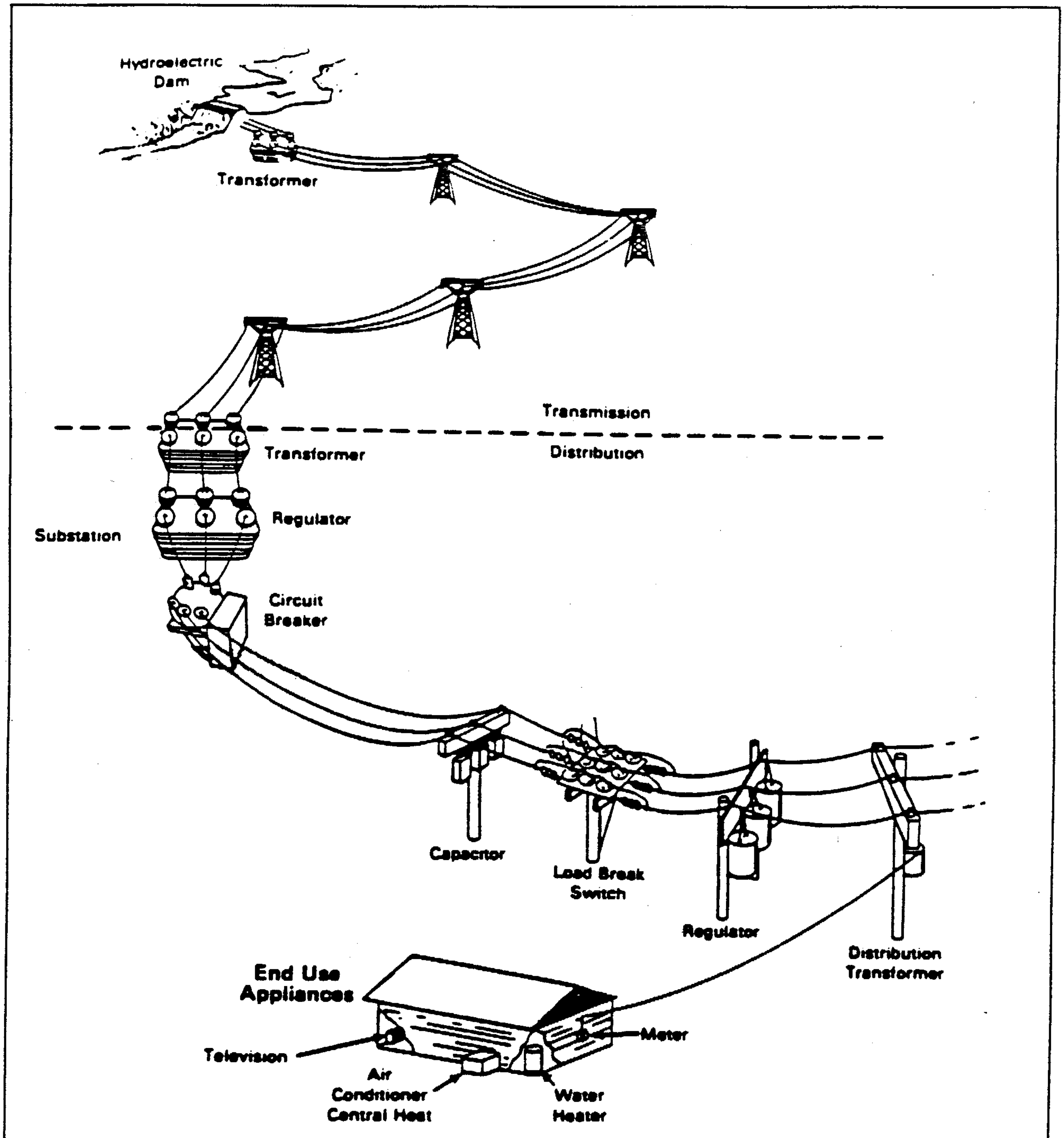
Transmission and distribution systems transport electric power from the generating plant to the retail customer. A simplified transmission and distribution system is illustrated in Figure 8-48. Step-up transformers increase voltage from the terminal voltage of the generating equipment (typically 13.8 kilovolts) to transmission voltage. Power is transported over long distances between generating plants and load centers on transmission lines. These operate at voltages of 69 to 500 kilovolts, or higher. Higher transmission voltages can reduce electrical losses and allow use of smaller transmission conductors. Near load centers, substation transformers reduce voltages from transmission levels to the voltage used for local distribution. Power is distributed from the substation to end users on primary distribution feeders. These run along streets and roads, above ground (overhead distribution), or buried (underground distribution), at voltages ranging from 2.4 kilovolts (older feeders) to as high as 34.5 kilovolts. Distribution transformers, located at intervals along the primary distribution feeders, reduce primary distribution voltage to customer service voltages (120 to 600 volts, depending on the user). Power is transferred from the distribution transformer to the end-user by secondary feeders.

Losses from transmission and distribution of electric energy are estimated to comprise about 7.5 to 9 percent of loads. Applying this estimate to the forecasted Pacific Northwest firm electric load of 18,100 average megawatts for operating year 1989-90 yields estimated regionwide transmission and distribution losses of about 1,360 to 1,630 average megawatts. Bonneville, having no distribution system, experiences lower losses as a percentage (about 2.5 percent) than the system as a whole. Bonneville's firm losses are estimated to be about 144 average megawatts for operating year 1989 to 1990 (PNUCC, 1989). Losses during peak loads can be significantly higher, because they are determined by the square of the current and the total impedance of the system. Peak losses become important for capacity-constrained systems or areas with transmission capacity constraints, such as those being experienced in the Puget Sound region.

This section includes an assessment of the loss reduction potential on both Bonneville's transmission system and non-Bonneville regional transmission and distribution systems. The estimated loss reduction potential on Bonneville's transmission system is based on the most recent reports of Bonneville's Loss Savings Task Force. The assessment of loss reduction potential on the non-Bonneville systems is based on Bonneville studies of loss reduction potential on its customer systems and consultations with regional utilities organized by the Pacific Northwest Utilities Conference Committee (PNUCC).

Transmission and Distribution

Figure 8–48
Simplified Diagram of Transmission and Distribution (BPA 1987)



The following section assesses regionwide technical and economic potential for loss reduction on transmission and distribution systems. Described next are possible environmental implications of transmission and distribution loss reduction measures. Following this, prospects for implementing loss reduction programs in the Pacific Northwest are described and achievable potential estimated. Finally, the Council's position regarding transmission and distribution loss savings are in the conclusion.

Loss Reduction Measures

A number of measures may be used to improve transmission and distribution efficiencies. These measures can be categorized as follows:

- Replacement of transmission and distribution system components, such as transformers and conductors, with components having lower electrical losses.

- Modification of system operating conditions, such as nominal voltage levels, to reduce losses.

- Modification of load characteristics to reduce transmission and distribution system losses. Examples include reducing peak loads and reducing reactive loads.

- Reconfiguration of the transmission and distribution system. An example is reconfiguring distribution feeders to reduce the average distance, and therefore losses between the substation and its loads.

In a study prepared for the Bonneville Power Administration, Westinghouse Electric Corporation assessed 88 measures, including 49 "state-of-the-art" measures and 39 "future" measures, as having potential to improve transmission and distribution system efficiencies (BPA, 1986). In that study, 15 of the 88 measures were identified as having the greatest potential benefit for Bonneville and its customers. Several of these 15 measures, such as revised transmission and distribution system design standards, are not in themselves loss reduction measures, but rather means of implementing transmission and distribution loss reduction. Moreover, not all of the "state-of-the-art" measures are commercially proven. The Bonneville study of loss reduction potential on Bonneville customer systems (BPA, 1987) was based on three commercially proven loss reduction measures with widespread application to regional transmission and distribution systems. These studies, and discussions with utility transmission and distribution staff suggest that the following loss reduction measures hold the greatest promise for application to the region's transmission and distribution system:

Reconductoring

Transmission and distribution conductors may be technically adequate to serve their intended load, yet may experience high losses due to conductor resistance. Substitution of larger, lower-resistance conductors for sizes that are just technically adequate may economically reduce system losses.

Increase Primary Distribution Feeder Voltage

Primary distribution feeders operate at voltages ranging from 2.4 to 34.5 kilovolts. Increasing the nominal operating voltage of a feeder will reduce the current carried and hence losses. Though effective for reducing losses, increasing primary distribution feeder operating voltage requires complete feeder rebuild and replacement of most components.

Reactive Power Control

Transmission and distribution systems transport both real and reactive power. Real power is the portion of the total power that provides useful energy to end users. Reactive power is consumed by certain end uses, particularly motors, but does not produce useful energy. But both reactive as well as real power transfers contribute to transmission and distribution system loads and losses. Real power must be generated at a generating plant, but reactive power can be supplied by capacitors and reactors, devices that can be located near the source of reactive power and thereby reduce reactive power transfer through the transmission and distribution system. This can reduce system loading and losses.

Feeder Reconfiguration

As utility systems have grown over the years, the physical and electrical configuration of distribution networks generally have not been optimized to minimize losses. For example, some distribution feeders may be carrying heavy loads, with attendant high losses, while nearby feeders remain lightly loaded. Reconfiguration would shift loads from heavily loaded feeders to more lightly loaded feeders, or would re-route loads to shorten the distance from the substation to the retail customer.

Phase Load Balancing

Primary distribution feeders generally consist of three physically separate conductors, one for each phase. As single-phase customers, such as residences, are added to a feeder, an attempt is made to equalize loads on each phase of the primary feeder. This minimizes losses. But daily and seasonal variation in loads, and long-term changes in the load of any single-phase customer may cause imbalance in the loads among feeder phases. Technology is being developed to dynamically balance three-phase feeder loads by use of devices that automatically switch loads among phases. This will minimize losses due to phase imbalance.

Peak Load Control

Because losses are proportional to the square of the load current, reductions in peak load will reduce transmission and distribution losses significantly. Various techniques, including pricing incentives and interruptible end-use equipment operation, are available for reducing peak loads, and related transmission and distribution system losses.

Distribution Automation

Any of the four measures discussed above (reactive power, feeder configuration, phase load balance and peak load) can be automatically managed to minimize system losses.

Amorphous Metal Core Transformers

Use of amorphous metal in lieu of conventional silicon steel for the magnetic cores of transformers can reduce transformer core energy losses up to 60 to 70 percent (EPRI, 1988). Although amorphous core transformers cost more than conventional silicon steel core transformers of equivalent capacity, their use to reduce losses may be cost-effective, particularly in light-load applications where transformer losses are dominated by core losses.

High-Efficiency Silicon Steel Transformers

Transformer losses can be reduced by replacing conventional silicon steel transformers with improved lower-loss designs, and by sizing conventional units to reduce peak loading.

Conservation Voltage Regulation

Reducing the electrical voltage supplied to customers to the lower half of the standard voltage control band increases the efficiency of certain types of end use equipment. The energy savings occur at the end-use and at distribution transformers. The measures are implemented only on the distribution system. Conservation voltage regulation is assessed in detail following this discussion of transmission and distribution loss reduction.

Improved Insulators

The porcelain insulators used in transmission and distribution systems allow a small current leakage to ground. Polymer-based insulators have lower leakage currents than conventional porcelain units and may reduce system losses.

Environmental Considerations

Other than local and generally minor disturbance during construction, transmission and distribution system loss reduction has few environmental effects. Two environmental issues that may be associated with transmission and distribution system loss reduction are electromagnetic field effects and the retirement of equipment containing polychlorinated biphenyl compounds.

Electromagnetic Field Effects

The voltage and current associated with the transport and use of electric power create electrical and magnetic fields that have the potential to affect biological processes. Certain epidemiologic studies have indicated a positive relationship between magnetic fields and adverse health effects. Two studies in the Denver area have shown some statistical correlation between cases of childhood cancer and nearby power lines carrying high-current loads. Other studies have shown some positive correlation between chronic occupational exposure to strong electromagnetic fields and cases of leukemia and brain cancer. The observed correlations between electromagnetic fields and disease in these studies is weak, and other environmental or social factors may contribute to, or be responsible for the observed effects. Moreover, other studies have produced conflicting results. Nevertheless there is sufficient concern that further research is underway to confirm or deny the hypothetical correlation between electromagnetic fields and health effects.

Certain transmission and distribution loss reduction measures can affect magnetic field strength. In particular, upgrading primary distribution feeder operating voltage reduces current flow and thereby the magnetic field associated with the feeder. But the association of adverse health effects with electromagnetic fields currently is too weak and uncertain to attribute health benefits to loss reduction measures that also reduce magnetic fields. Further research should better establish the relationship, if any, between magnetic fields and adverse health effects.

Polychlorinated Biphenyl (PCB) Disposal

Certain transmission and distribution system components including transformers and capacitors are filled with oil for electrical insulation and cooling. The cooling oil of older units contained polychlorinated biphenyl compounds (PCBs), prized for their insulating properties and inflammability. PCBs have been found to be carcinogenic, and are not allowed in new equipment. Old equipment found to contain PCBs is decontaminated or disposed of under controlled conditions.

Transmission and distribution system loss reduction programs will accelerate the removal of PCB and PCB-contaminated equipment. This may create some additional interim hazard of inadvertent PCB releases through the handling and disposal of PCB-containing equipment. These can be minimized through proper handling and disposal procedures. In the long-run, loss reduction programs should result in more rapid reduction in the overall hazard from PCB compounds as the stock of older, less efficient components, containing PCBs is eliminated.

Technical and Economic Potential in the Pacific Northwest

This section discusses the potential for transmission and distribution system loss reduction in the Northwest. Discussed first are potential savings by the Bonneville system. This is followed by a discussion of potential savings by the region's utility systems.

The Bonneville Transmission System

Over the past several years, Bonneville periodically has convened a Loss Savings Task Force. This Task Force has assessed opportunities for loss reductions through upgrades to the Bonneville transmission system. Promising loss savings opportunities have been recommended for inclusion in Bonneville's budget (BPA 1984, 1987a, 1987b) only when cost-effective. In general, cost-effectiveness has been defined under the conditions of surplus that existed when these reports were written. Now that resources are needed, more can be done under the cost-effective limits.

The 1986 Power Plan included 34 megawatts of potential loss savings on the Bonneville transmission system. These savings were estimated to be available at costs less than 50 mills per kilowatt-hour (real levelized cost of savings) based on the Fiscal Year 1985-1986 Loss Savings Task Force report (BPA, 1984).

Potential loss savings for the Bonneville transmission system have been reassessed using the 1987 updates to the Fiscal Year 1985-1986 Loss Savings Task Force Report and the financial assumptions in use by the Council for preparation of this power plan (see Table 8-49). This reassessment suggests that there are potential loss savings of about 43 megawatts on the Bonneville transmission system at nominal levelized energy costs of 15 cents per kilowatt-hour or less. Excluded from these estimates are 26 megawatts of possible savings from constructing a parallel line to the existing DC intertie. These latter savings would largely be of nonfirm energy and are excluded for that reason. Also, not included are possible savings resulting from upgrade of trans-Cascade transmission from Chief Joseph to the Puget Sound area. A tabulation of estimated savings on the Bonneville transmission system is provided in Table 8-49.

Table 8-49
Estimated Cost and Availability of Loss Savings or the Bonneville Transmission System

Levelized Energy Cost (Cents/kWh)	Cumulative Loss Savings (MWa)
1	2.3
2	2.3
3	9.8
4	13.1
5	14.4
6	16.7
7	18.6
8	25.5
9	26.7
10	35.8
11	35.8
12	43.1
13	43.1
14	43.1
15	43.3

The Non-Bonneville Transmission and Distribution Systems

The assessment of the cost and availability of energy savings through loss reduction on transmission and distribution systems other than those of Bonneville's is based on a customer system efficiency improvement (CSEI) study prepared for Bonneville by Pacific Northwest Laboratory (PNL, 1987). The Council and PNUCC conducted a series of consultations with transmission and distribution system staff of regional utilities to verify and update the assumptions and methodology used in the CSEI study.

The Bonneville CSEI study was a "top down" study intended to produce an approximation of the cost and magnitude of regionwide loss savings potential for use in long-term regional planning. The results of the study were not intended to be used as the basis for estimating loss reduction potential on any given transmission line or distribution feeder. Assessment of the loss reduction potential on a given transmission line or distribution feeder requires an individual engineering study.

Regional Transmission and Distribution System Component Census

The CSEI study focussed on system components known through previous studies to be responsible for the greatest proportion of transmission and distribution system losses. These components include distribution transformers, substation transformers, transmission conductors and primary distribution feeder conductors. A census of the regionwide population of these components was developed through a survey administered to 144 Bonneville customers. The estimates of the regionwide population of these components are shown in Table 8-50. The breakouts by investor-owned and publicly owned utility systems are approximate within each component type.

Reduction Measures

The CSEI study assessed the availability and cost of loss savings from components that are responsible for most transmission and distribution system losses. The following measures were considered the most promising.

- Replacement of existing distribution transformers with conventional silicon steel core transformers of greater efficiency.

- Replacement of existing substation transformers with conventional silicon steel core transformers of greater efficiency.

- Replacement of existing transmission conductor with conductor of three standard sizes larger.

- Replacement of existing primary distribution feeder conductor with conductor of three standard sizes larger.

- Upgrading the nominal voltage of 12.5 kilovolt primary distribution feeders to 34.5 kilovolt.

Measure Costs and Performance

Cost information for the CSEI study was derived from utilities, equipment vendors and published literature. For most measures, equations relating the cost of equipment to its physical or electrical characteristics were derived by regression analysis of specific component data. This was done to facilitate estimation of costs for a wide variety of equipment ratings, including systemwide averages not corresponding to standard equipment ratings.

Distribution Transformers

The cost and performance characteristics of existing-grade distribution transformers and high-efficiency replacements, as calculated by the regression equations of the CSEI study, are shown in Table 8-51. The costs of Table 8-51 have been escalated to 1988 dollars using the Handy Whitman Index of public utility costs.

The costs in Table 8-51 include no allowance for installation, nor do they include engineering or administrative costs, nor contingency allowances. But installation costs for high-efficiency equipment should be no greater than for equipment of standard efficiency. Because this assessment assumes that high-efficiency equipment is installed when replacement of existing stock is needed, installation costs, being the same for standard or high-efficiency equipment of similar rating, should not affect the incremental costs attributable to the measures. However, engineering costs, administrative costs and contingency allowances have been incorporated into the calculation of measure cost-effectiveness (see below).

The CSEI study did not consider the replacement of standard silicon steel core transformers with amorphous metal core transformers because of the early stage of commercial deployment of amorphous metal units at that time. Amorphous metal core distribution transformers have since become commercially available. Examples of amorphous core transformer cost and performance, taken from bid sheets, are shown in Table 8-52.

Table 8-50
Estimated Pacific Northwest Population
of Transmission and Distribution System Components

Component	Average Size	Population: IOU Systems (units)	Population: POU Systems (units)
Distribution Transformers			
0-7.5 kVA[a] units	5 kVA	28,140	16,500
7.6-15.0 kVA units	10 kVA	274,000	161,000
15.1-25.0 kVA units	15 kVA	209,000	123,000
25.1-40.0 kVA units	28 kVA	85,400	50,200
40.1-50.0 kVA units	48 kVA	109,000	64,200
50.1-75.0 kVA units	52 kVA	74,700	43,900
75.1-100.0 kVA units	75 kVA	15,500	9,120
100.1-200.0 kVA units	118 kVA	11,600	6,830
200.1-300.0 kVA units	232 kVA	4,020	2,360
300.1-500 kVA units	305 kVA	2,210	1,300
500+ kVA units	1,032 kVA	1,900	1,120
Substation Transformers			
0-7.5 MVA[b] Units	5.7 MVA	489	299
7.6-20.0 MVA Units	11.1 MVA	104	63
20+ MVA Units	56.0 MVA	147	90
		(Circuit Miles)	(Circuit Miles)
Primary Distribution Feeders			
0-11.9 kV feeders	4 AWG[c]	1,650	1,860
12.0-17.0 kV feeders	2/0 AWG	20,300	22,900
18.0-50.0 kV feeders	1 AWG	5,610	6,320
Transmission Lines			
34.5 kV circuits	2/0 AWG	3,912	690
69 kV circuits	2/0 AWG	3,615	638
115 kV circuits	336.4 Mcmil[d]	10,268	1,812
230 kV circuits	874.5 Mcmil	3,536	624

a Kilovolt - ampiers.
b Megavolt - ampiers.
c American Wire Gauge (conductor size).
d Thousand circular mills (cable size).

Table 8-51
Cost and Performance of Silicon Steel Core Distribution Transformers

Nameplate Rating (kVA)[a]	Efficiency (%)	No-Load Loss (watts)	Load Loss (watts)	Equipment Cost ($/unit)
Typical - Existing Stock				
7	98.5	34	73	$345
15	97.0	115	340	$382
25	97.2	169	519	$490
40	97.7	219	683	$657
50	98.0	243	761	$771
75	98.4	286	903	$1,057
100	98.7	317	1,004	$1,348
200	99.2	391	1,247	$2,553
300	99.4	434	1,389	$3,813
500				
500+				
High-Efficiency Units				
7	98.3	28	89	$345
15	97.9	78	240	$403
25	98.2	111	341	$521
40	98.6	142	434	$708
50	98.7	157	478	$836
75	99.0	183	558	$1,167
100	99.2	202	615	$1,511
200	99.5	247	752	$2,992
300	99.6	274	832	$4,624
500	99.8	307	934	$8,274
500+	99.6	488	1,567	$6,474

[a] Kilovolt - ampiers.

Table 8-52
Example Cost and Performance
Amorphous Metal Core Distribution Transformers

Nameplate Rating (kVA)[a]	Efficiency (%)	No-Load Loss (watts)	Load Loss (watts)	Equipment Cost ($/unit)
25	99.0	28	213	$848
25	98.9	19	253	$895
50	99.1	36	413	$1,258
50	99.0	31	481	$1,190
75	99.2	50	526	$1,882
100	N/A	N/A	N/A	$2,164

[a] Kilovolt - ampiers.

Substation Transformers

Because the CSEI study reports do not provide sufficient background information to permit disaggregation of substation transformer cost estimates, substation transformer upgrades were omitted from this analysis. (Upgrade of substation transformers with more efficient transformers was found in the CSEI study to provide only several megawatts of loss reduction.)

Reconductoring

Table 8-53 shows the cost and performance assumptions used in the CSEI study for reconductoring of primary distribution feeders and transmission lines. Unlike the transformer costs of Tables 8-51 and 8-52, these cost estimates include installation costs. Thus, the costs may be overstated since the cost-effectiveness of loss reduction activities is based on incremental costs of these measures. Engineering and administrative costs and contingency allowances are excluded. Costs have been adjusted to 1988 dollars.

Table 8-53
Cost and Performance of Transmission and Distribution System ACSR[a] Conductors

Size (AWG)[b]	Size (Mcmil)[c]	Resistance (Ohm/mile)	Cost (New Construction) ($/mile)	Cost (Reconductoring) ($/mile)
--	1,033.5	0.104	$72,100	$79,800
--	874.5	0.123	$65,800	$73,500
--	500.0	0.206	$50,800	$58,500
--	336.4	0.306	$44,300	$52,000
--	266.8	0.385	$41,500	$49,200
3/0	167.8	0.720	$37,600	$45,300
2/0	133.1	0.890	$36,200	$43,900
1	83.7	1.380	$34,200	$41,900
4	41.7	2.570	$32,600	$40,300

a Aluminum conductor steel reinforced.
b American Wire Gauge (conductor size).
c Thousand circular mills (cable size).

Voltage Upgrade

The cost of upgrading 12.5-kilovolt primary distribution feeders to 34.5-kilovolt service was also estimated in the CSEI study. This upgrade was assumed to require replacement of substation transformers, distribution transformers and conductor insulations. As with the other loss-reduction measures considered, it was assumed that the upgrade would be implemented only when rebuilding of the feeder would be required for other reasons. Therefore, only the incremental costs of the materials required for voltage upgrade were considered. Insulator replacement was estimated to cost $1,974 per mile (1988 dollars), excluding engineering and administrative costs and contingencies, based on interviews with utility staff. Distribution transformer replacements were assumed to be high-efficiency conventional units available at the costs shown in Table 8-50. Substation transformers were assumed to be replaced with conventional units.

However, distribution engineering staff of regional utilities have advised the Council staff that upgrading the voltage of primary distribution feeders would require more extensive equipment replacement than assumed in the CSEI study. In addition to replacement of transformers and insulators, it also would be necessary to replace trimline brackets, lightning arrestors, fuses, cutouts, reclosers, capacitors, primary metering equipment and customer-owned equipment served at primary distribution voltages. Additional costs would be incurred for feeders having underground sections, for which conductors, vaults and ducts would have to be replaced. Moreover, the reliability of 34.5 kilovolt underground cables has been questioned because of insulation failures. Finally, the upgraded feeder typically would have to be installed as a new system parallel to the existing feeder prior to removal of the existing system in order to maintain continuity of service. The costs of the upgraded feeder would essentially be new system costs less any salvage value of the old components.

Because of uncertainties associated with the voltage upgrade measure, this measure was not considered further.

Operation and Maintenance Costs

Operation and maintenance costs should not be affected by these measures unless voltage levels are changed. Increased operating voltage, such as that resulting from increasing primary distribution feeder voltage, would increase operation and maintenance costs.

Levelized Energy Cost of Loss Reduction Measures

The levelized life-cycle cost of energy savings for each loss reduction measure was calculated for investor-owned utilities and for consumer-owned utilities. The assumptions used for these calculations are shown in Table 8-54.

Table 8-54
Assumptions for Calculating the Levelized Energy Cost of Transmission and Distribution System Loss Reduction Measures

Financing	
IOU Systems - Debt/Equity Ratio	50:50
IOU Systems - Return on Equity	12.9% (Nominal)
IOU Systems - Interest on Debt	11.3% (Nominal)
POU Systems - Debt/Equity Ratio	100:0
POU Systems - Interest on Debt	8.2% (Nominal)
Bonneville Systems - Debt/Equity Ratio	100:0
Bonneville Systems - Interest on Debt	9.2% (Nominal)
Discount Rate	8.15% (Nominal)
Amortization life	30 years
Escalation and Inflation	
Rate of Inflation	5%
Capital Cost Escalation	0.0% (Real)
O&M Cost Escalation	0.0% (Real)
Cost Assumptions	
Engineering	8% of direct capital costs
Administrative and General	9% of direct capital costs
Contingency	20% of direct and indirect capital costs
Engineering Lead Time	12 months
Construction Lead Time	12 months
Operating Assumptions	
In-service Year	January 1988
Service life	30 years

These assumptions yield the levelized energy costs shown in Table 8-55. Levelized energy costs are in nominal dollars for a reference in-service year of 1988.

Regional Potential: Transmission and Distribution Loss Reduction

It may not be feasible to upgrade every component of the existing transmission and distribution system using the measures described above. For example, most underground feeder conductors are buried and would require excavation for replacement. But, all are assumed to be upgraded during normal replacement. The likely penetration of these loss-reduction measures was not assessed in the CSEI study. That study simply assumed that the measures could be applied to all components at the estimated cost. The Council is using the following technical application fractions until better information becomes available:

Distribution transformer upgrade	90 percent of units
Reconductor primary distribution feeders	75 percent of circuit miles
Reconductor transmission circuits	75 percent of circuit miles
Bonneville transmission upgrades	100 percent of identified projects

Table 8-55
Levelized Energy Cost
of Transmission and Distribution System Loss Reduction Measures
(Nominal dollars, 1988 In-service)

Measure	IOU Systems (cents/kWh)	COU Systems (cents/kWh)
Upgrade Distribution Transformers		
0-7.5 kVA[a] units (5 kVA average)	1.7	1.2
7.6 to 15.0 kVA units (10 kVA average)	1.8	1.2
15.1 to 25.0 kVA units (15 kVA average)	1.7	1.2
25.1 to 40.0 kVA units (28 kVA average)	1.0	0.7
40.1 to 50.0 kVA units (48 kVA average)	1.0	0.7
50.1 to 75.0 kVA units (52 kVA average)	1.3	0.9
75.1 to 100.0 kVA units (75 kVA average)	2.0	1.4
100.1 to 200.0 kVA units (118 kVA average)	3.9	2.7
200.1 to 300.0 kVA units (232 kVA average)	6.9	4.7
300.1 to 500 kVA units (305 kVA average)	9.6	6.6
500+ kVA units (1,032 kVA average)	48	33
Reconductor Primary Distribution Feeders		
0 to 11.9 kV feeders (4 AWG[b] to 1 AWG)	4.6	3.2
12.0 to 17.0 kV feeders (2/0 AWG to 266.8 Mcmil)[c]	5.2	3.6
18.0 to 50.0 kV feeders (1 AWG to 3/0 AWG)	8.0	5.5
Reconductor Transmission Lines		
34.5 kV circuits (2/0 AWG to 266.8 Mcmil)	56	38
69 kV circuits (2/0 AWG to 266.8 Mcmil)	15	10
115 kV circuits (336.4 Mcmil to 500.0 Mcmil)	7.0	4.8
230 kV circuits (874.5 Mcmil to 1,033.5 Mcmil)	7.1	4.8

a Kilovolt - ampiers.
b American Wire Gauge (conductor size).
c Thousand circular mills (cable size).

Applying these technical application fractions to the component inventory of Table 8-50 yields the estimates of transmission and distribution system loss reduction technical potential of Table 8-56. The penetration constraints are not applied to the estimated loss reduction potential on Bonneville's system because the Bonneville estimates are based on specific projects identified by the Loss Savings Task Force.

Table 8-56
Technical Potential
Transmission and Distribution System Loss Reduction
in the Pacific Northwest
(Average Megawatts)

	IOU Systems	COU Systems	Bonneville Systems
Upgrade Distribution Transformers	45	26	0
Reconductor Primary Distribution Feeders	39	44	0
Reconductor Transmission Lines	23	4	0
Bonneville Transmission Upgrades	--	--	43

Several factors may discourage full implementation of the technically available transmission and distribution loss reduction potential. Among these are:

Spurious Marginal Resource Price Signals

As with other conservation resources, transmission and distribution system loss reduction up to the regionally cost-effective level can be viewed as having a price-induced component and a component that may not be achieved through price incentives. The price-induced component of transmission and distribution system loss reduction includes measures whose cost is less than the utility's marginal cost of new resources. To the extent that the utility sees a long-term marginal resource cost equivalent to that of the region, the regionally cost-effective transmission and distribution loss reduction potential on that utility's system should be fully captured. But, if a utility sees a long-term marginal resource cost less than that of the region, only a portion of the regionally cost-effective loss reduction potential on that utility's system will be acquired. The remainder of the regionally cost-effective potential must be secured by other incentives.

Some utilities use Bonneville wholesale rates as their long-term marginal resource cost. Because Bonneville wholesale rates are based on average, not marginal resource cost, only a portion of the transmission and distribution loss reduction potential on these systems can be expected to be acquired by these utilities acting in their self-interest. Utilities using forecast Bonneville wholesale rates as their long-term new resource cost will not have an incentive to capture all regionally cost-effective loss reduction measures.

Engineering Capability

Large utilities maintain transmission and distribution engineering staff capable of identifying opportunities for cost-effective loss reduction actions and preparing programs for the recovery of these losses. Smaller utilities, however, may lack this in-house engineering expertise. These utilities often rely upon outside contractors for transmission and distribution engineering services.

Limited Return on Investment

Transmission and distribution system loss reduction generally comes in small increments. The opportunities for improvement generally arise on a line-by-line basis and the potential savings from upgrade of an individual feeder or transmission line generally are quite small. For this reason, loss reduction proposals may be a difficult sell in an organization where many projects compete for funding.

Other factors may encourage implementation of transmission and distribution loss-reduction actions. These include:

Improved Service

Some distribution system loss reduction measures, including reconductoring and feeder voltage upgrade, will reduce voltage drop along distribution feeders. This may alleviate substandard voltage conditions at the far ends of distribution feeder networks. This improvement in service quality could serve as an inducement to implementation of loss-reduction programs.

Reduced Wholesale Power Cost

Transmission and distribution system loss reduction will reduce wholesale power purchase or generating requirements, but will not affect retail sales. Utilities should therefore have an incentive to invest in loss reduction measures that cost less than their marginal power production or purchase costs.

Utility Control over the Affected System

Unlike end-use conservation measures, a utility owns and operates the equipment affected by transmission and distribution systems loss reduction measures. This should facilitate implementation of loss-reduction measures on these systems.

The factors described above must be considered when estimating the achievable potential for cost-effective energy savings from transmission and distribution loss reduction. In estimating achievable potential, we assume that programs can be established to provide incentives for recovery of the cost of measures that are regionally cost-effective, although these measures may not be cost-effective for an individual utility. Furthermore, we assume that programs can be established to allow small utilities to secure the engineering expertise for analyzing loss reduction opportunities. Assuming that such programs are established, the principal factors constraining recovery of transmission and distribution losses appear to be the timing constraints imposed by the rebuild/replacement cycle of the existing system and possible low funding priority for transmission and distribution loss recovery activities.

These remaining constraints should have a minor impact on ultimate penetration of loss-reduction measures. Because of the factors that encourage transmission and distribution loss reduction, ultimate penetration can be expected to exceed that of end-use conservation programs (currently assumed to be 85 percent for most end-use conservation programs). The Council therefore decided to use a 90 percent ultimate penetration rate for transmission and distribution loss reduction. This suggests that at a minimum, regionwide energy savings of at least 200 megawatts from transmission and distribution loss reduction are achievable at costs less than 15 cents per kilowatt-hour. Of this total, 96 megawatts are available on investor-owned utility systems, 67 megawatts on consumer-owned utility systems, and 39 megawatts on Bonneville's system.

Further analysis may identify additional savings potential. For example, it is likely that some distribution voltage increases are cost-effective, particularly on older, low-voltage primary distribution feeders. In addition, savings from amorphous metal core distribution transformers and high-efficiency conventional core substation transformers also may be cost-effective. Therefore, it seems likely that the Council's savings estimate is conservative.

Because loss reduction measures generally are cost-effective only when implemented in conjunction with equipment replacement or rebuild occurring for other purposes, the energy savings potential will be secured only slowly. If we assume that the typical component lifetime is 30 years, then the maximum penetration rate for these savings will be 3.33 percent per year. The staff is seeking additional information on the age distribution of existing equipment that may permit refinement of this penetration rate estimate.

Conclusions: Transmission and Distribution Loss Reduction

Improvements to the efficiency of the region's transmission and distribution systems offer opportunities for securing at least 200 megawatts of energy savings at costs of 15 cents per kilowatt-hour, or less. About 39 megawatts of these savings are available on the Bonneville transmission system, 96 megawatts on the transmission and distribution systems of investor-owned utilities, and 67 megawatts on the transmission and distribution systems of consumer-owned utilities. These estimates represent about 12 to 15 percent of regionwide transmission and distribution system losses. Additional savings may be possible from measures that have not yet been analyzed. These savings can be achieved at costs ranging from less than 1 cent per kilowatt-hour to 15 cents per kilowatt-hour. These savings could begin to be secured as early as 1994, but 20 to 30 years might be required to secure the full potential.

The technologies for securing these savings are well-established. Many of these savings likely will be price-induced, and there are several factors that should work to encourage acquisition of these savings. There are, however, several factors that unless corrected will inhibit recovery of a portion of these potential savings. One is the cost of new resources as seen by utilities purchasing from Bonneville at average cost prices. Another is the lack of staff with the necessary transmission and distribution expertise, particularly for smaller utilities. Actions can be taken, however, to remedy these constraints.

In view of the attractive cost and environmental qualities of transmission loss reduction measures, the Council recommends that Bonneville and the utilities begin immediately to acquire these resources, wherever cost-effective.

Conservation Voltage Regulation

Conservation voltage regulation is a set of measures and operating strategies designed to provide electricity service at the lowest practicable voltage level while meeting the standards for voltage adopted by the American National Standards Institute (ANSI). The standard for typical residential buildings is set at 114 to 126 volts at the customer's service meter. The theory behind conservation voltage regulation is that many appliances and other end-uses of electricity operate more efficiently at reduced voltage levels, resulting in electricity savings and capacity savings to the utility, and cooler and longer-lived appliances. In addition, transformers on utility distribution lines run more efficiently, last longer, and have lower no-load losses.

The conservation voltage regulation resource is not easy to estimate on a regional basis, because the size and availability of electricity savings are specific to each distribution feeder. However, from reviewing regional estimates, the experience of California utilities, and the experience of the Snohomish County Public Utility District, the Council concluded that all utilities should consider the effectiveness of conservation voltage regulation on their distribution systems. The Council considered 100 megawatts of energy savings to be achievable through implementation of improved voltage regulation.

A review of the available information shows clearly that electricity sales and demand are reduced when conservation voltage regulation is implemented. What is not yet totally clear is how the savings are allocated to the various end-uses that are affected.

Methods to Achieve Conservation Voltage Regulation

Theoretically, distribution circuits could be configured to maintain exactly 114 volts at every consumer service box. However, conservation voltage regulation implemented to this degree would probably not be cost-effective, because the capital costs of voltage regulating devices would be much higher than the current strategies being implemented. Typically, utilities have opted for low-cost strategies with controlled voltage drop along distribution feeders. Capital equipment cost is minimized, and savings are obtained at very low costs. However, it is likely that additional cost-effective savings could be attained with additional measures.

Controlled voltage drops are designed to lower the average delivered voltage, for example, from about an average of 120 to 117.5 volts. The voltage drop along a distribution feeder is determined by the impedance[45] of the line, the loading of the line, and the distance from the substation. A simplified depiction of voltage drop is shown in Figure 8-49 for a line on which conservation voltage regulation strategies have not been implemented. In this example, the voltage level at the substation is 126 volts and it drops to about 123 volts when the feeder is lightly

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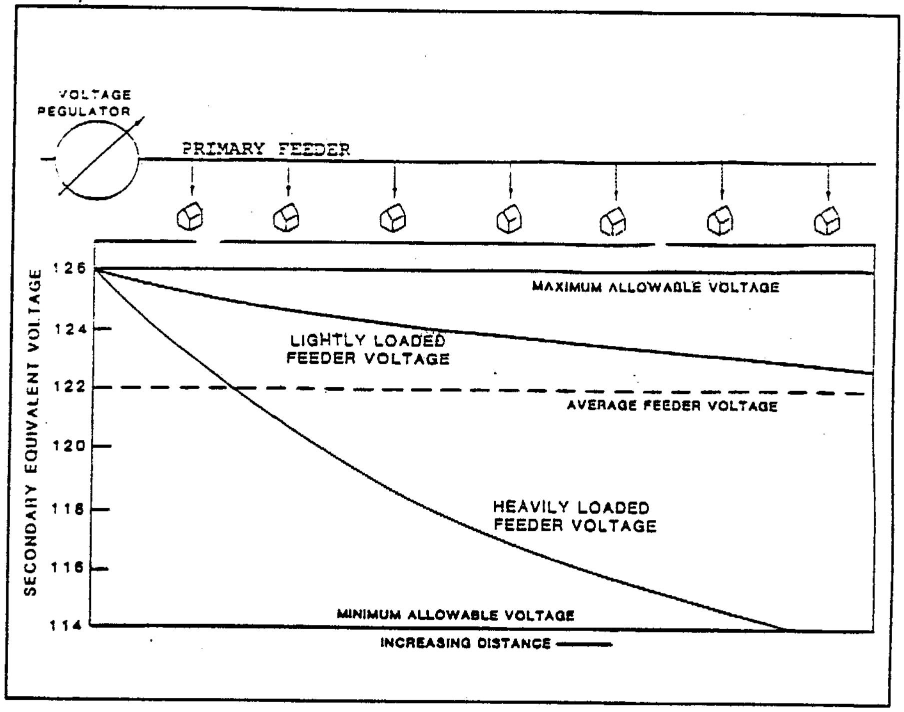
45./ Impedance is a function of resistance and reactance. Impedance (Z) is equal to the square root of the quantity resistance (R) squared minus reactance (X).

loaded, and to about 114 volts when the feeder is heavily loaded during periods of peak demand. As can be seen in Figure 8-49, the benefits of low voltage are achieved only serendipitously by customers at the end of the feeder during heavily loaded times. The objective of conservation voltage regulation is to find ways to regulate the voltage so that lower voltages are delivered during all loading conditions. Figure 8-49 shows that the voltage during light-loaded conditions drops only about 3 volts, from 126 to 123. If the voltage at the substation could be decreased easily to 117 at lightly loaded periods and the same 3-volt drop occurred, all users would be provided with lower voltage levels under light-load conditions. "Line drop compensation," which adjusts substation voltage to maintain 114 volts at the end of the feeder, is the technique used by most utilities. Line drop compensation controls allow the voltage at the substation to increase while always maintaining 114 volts at the end of the line. This situation is depicted in Figure 8-50. It shows initial voltages at the substation that vary with the loading on the feeder. At high-load times, the voltage at the substation is higher to allow for the greater voltage drop accompanying higher loads. At light-load times, voltage is reduced automatically to 118 volts at the substation and drops to 114 volts at the end of the feeder, the same as under high-load conditions.

This description is, of course, simplified. The conservation voltage regulation strategy depicted here works with ideal feeders that are short and serve loads with suitable attributes. Longer feeders will probably need other voltage regulating equipment and circuits feeding unstable loads undoubtedly will have to have more sophisticated equipment installed.

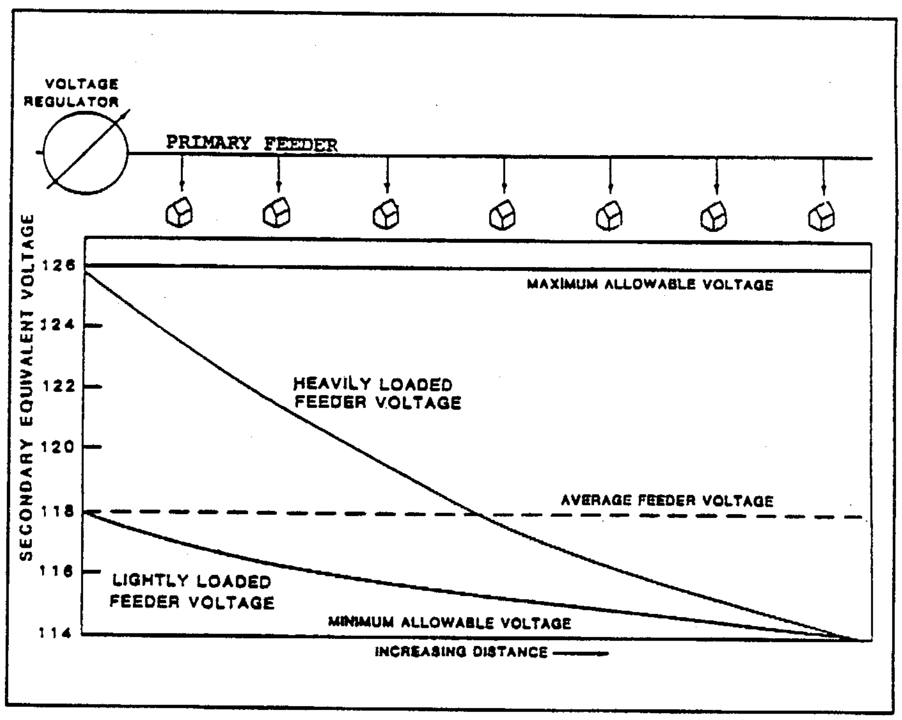
Voltage Profile— no CVR

Figure 8–49
Voltage Profile with no Conservation Voltage Regulation



Voltage Profile— with CVR

Figure 8–50
Voltage Profile with Conservation Voltage Regulation



Effectiveness of Improved Voltage Regulation

Typically, utilities deliver about 120 volts on average at the customer's meter. Conservation voltage regulation strategies aim at controlling the voltage to the lower end of the acceptable range of 114 to 126 volts, yielding an average of about 117.5 volts. Typical findings are that a 1 percent reduction in voltage returns about a 1 percent reduction in energy use. However, in the Northwest, where there is a higher concentration of electric resistance heating, savings probably will be less than is typical for the rest of the country. Thus, conservation voltage regulation that lowers the average from 120 volts to 117.5 volts would be expected to save 2.5 percent, or less, of the energy delivered on each circuit where conservation voltage regulation is employed. In the Northwest, the savings at this level of reduction may be as low as 1.25 percent, or one-half what has been experienced elsewhere. This estimate can be proven only by demonstrating conservation voltage reduction in the Northwest. The change in peak loads on the lines is less well known, but should be at least proportional to the energy savings.

The applicability of conservation voltage regulation to a particular utility or distribution circuit cannot be determined without detailed knowledge of the load on the feeder. For example, at Snohomish County Public Utility District, it has been determined that one year of detailed data is needed on each feeder before deciding whether and how to control the voltage on a specific feeder.[46]

Reported conservation voltage regulation savings derive from four different sources: 1) End-uses and system components that save both energy and capacity with no degradation of consumer's service, 2) end-uses that save energy and capacity with some, albeit apparently small, degradation in service, 3) end-uses that exhibit no energy or capacity savings, and 4) general effects of conservation voltage regulation on industrial and agricultural loads. As noted above, the rule of thumb is that for every 1 percent decrease in the average delivered voltage, a 1 percent decrease in energy is obtained, although in the Northwest the savings may be as low as .5 percent.[47] As will be shown below, this number can differ significantly depending on the utility, the characteristics of the distribution feeder, and the loads the feeder serves. The allocation of total savings to the various components within the building and on the utility's distribution feeder is not known with any degree of precision.

Effects of Conservation Voltage Regulation on Small Motor and Electronic Loads

Single-phase motors, those used in household appliances, run cooler and, as a result, more efficiently at voltages nearer the bottom of the ANSI standard range. As a result of running cooler, reliability is improved and lifetimes are extended. Efficiency gains are achieved without compromising the performance of the appliances.

46./ Based on telephone communication with Bob Fletcher of Snohomish County Public Utility District.

47./ Based on telephone communication with Bob Fletcher of Snohomish County Public Utility District.

However, if the voltage falls below the ANSI range, performance of these appliances can fall off. Shrinking television pictures are an example of what might happen if voltages fall below the standard range. However, in general, where conservation voltage regulation has been implemented, there have been relatively few complaints about the effects of low voltage from customers. In fact, it appears that there still are more complaints due to high voltage than to low voltage.

Distribution transformers, which reduce circuit line voltages from 12 kilovolt levels or higher to customer service voltages (114 to 126 volts for residential service) experience fewer losses at lower voltages. The amount of the total energy savings attributed to the lower loading on the distribution transformers has not been determined adequately. However, as mentioned earlier, the no-load (fixed) loss reduction on the distribution transformers is well known.

Effects of Conservation Voltage Regulation on Lighting Loads

Conservation voltage regulation will reduce the energy and capacity requirements for lighting, but at the expense of reduced lighting levels. Because the lighting levels are reduced by only several percent, some have considered these savings to be included under the definition of conservation as it is defined by the Act and applied by the Council. But "savings" of these kinds should not be considered as conservation. Nonetheless, there may be times when reduced lighting for a short period of time, to enable utilities to handle peak load, would be acceptable. Again, because the savings from conservation voltage regulation have not been broken out individually, it is difficult to know how much of the savings is reduced amenity in lighting. There has been no mention of complaints from reduced lighting levels due to conservation voltage regulation. This may be a manifestation of most areas being overlit to begin with, or it could mean that some individuals react to conservation voltage reduction by installing higher wattage lights, not perceiving why the lighting has dimmed.

Effects of Conservation Voltage Regulation on Resistance Heating Loads

When voltages are reduced, resistance heating elements used in electric furnaces and hot water heaters operate at lower temperatures. This means that the elements must remain on longer to produce the same amount of heat or hot water. The total amount of energy used remains the same. Energy for heating is determined by the difference in indoor and outdoor temperatures, thermostat settings in the house, and the thermal integrity of the house, among other things. Energy for heating hot water is determined by the difference in temperature between the incoming water and the thermostat setting, and the thermal integrity of the tank and piping system, among other things. Because conservation voltage regulation changes none of these parameters, the total amount of energy is not changed.

Some analysts have reported capacity savings, because each individual element is now drawing fewer kilowatts of electricity per unit of time. This conclusion ignores the fact that under ordinary operating conditions each element's contribution to peak is less than the rated capacity of the element. Because heating elements are not on continuously, but instead cycle on and off, the contribution of each to peak is based on the probability of the element being on times its rated capacity. When the capacity demand of the element is reduced by conservation voltage regulation, the length of time the element is on is increased by the same percentage, and the net effect of each element on capacity is unchanged. Thus, there should be no net effect of conservation voltage regulation on energy or capacity for resistance heating loads. There is one possible exception to this general rule. Because individuals take showers, baths, and raise thermostats within a couple of hours of one another, typically in the morning, conservation voltage regulation might lower and broaden the morning peak. Further statistical analysis is needed to confirm this hypothesis. In any case, conservation voltage regulation would result in no energy savings from resistance loads. There is a minor benefit to consumers, however, in that the life of resistance heating elements is apparently lengthened.

Effects of Conservation Voltage Regulation on Agricultural and Industrial Loads

Most studies of conservation voltage regulation confirm that there is little savings from industrial or agricultural loads. The studies are somewhat unclear as to why this is, but apparently three-phase motors, often used in industrial and agricultural processes, do not respond to conservation voltage regulation as well as the single-phase motors used in residential and commercial end-uses.

Large industrial motors often are custom-designed for the specific load[48] and are often designed to run optimally within a fairly small voltage range. Reducing voltage on these motors will affect the torque (i.e., the turning force) of the motor. The resulting torque depends on the voltage level in the following way: if the voltage is reduced to 90 percent of the designed voltage, the resulting torque would be reduced to the square of 90 percent times the initial torque. This would reduce torque to 81 percent of its design value and could affect the ability of the motor to do the work it was designed to do.[49] Conservation voltage regulation on circuits feeding industrial loads therefore might not be wise. However, it must be repeated that conservation voltage regulation is specific to the distribution feeder in question. Savings have been achieved on agricultural and industrial feeders, but they have been smaller than those achieved on lines feeding residential and commercial loads.

In addition, with industrial loads, it appears to be more difficult to control voltages within the more narrow band required to achieve conservation voltage regulation, because the stability of power use in industrial plants is not as good as in residential and commercial applications. The power profiles show spikes, notches, harmonics, and so forth that are hard to dampen, and if the voltages were to drop below the lower level of the ANSI range, it could affect sensitive equipment such as small computers in industrial plants. The variations in the

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48./ The information contained in this paragraph came from personal communication with a large AC motors expert from Toshiba International.

49./ Having said this, it is important to recognize that utilities supply voltage to industrial customers within plus or minus 5 percent of the expected level. Thus, industry is familiar with running motors over a range of voltage supply. Alternatively, industrial facilities may maintain their own voltage regulating equipment within their plants.

power profile in industrial plants apparently are caused by the type of loads in the facility, not necessarily by the utility's distribution system.

Experience of California Utilities in Applying Conservation Voltage Regulation

The California Public Utility Commission has required utilities in that state to employ conservation voltage regulation strategies on all of their applicable distribution lines. The PUC order came out in 1977. As of the end of 1985, there were 7,169 distribution circuits in California. Of these, 5,717 were considered candidates for conservation voltage regulation strategies and 4,298 of these already had been made "conservation voltage regulation compliant." That left 1,419 distribution circuits to be brought into compliance with the PUC order. Of these, 222 were considered to be cost-effective conservation voltage regulation candidates using the cost of power estimates in 1985, the criterion used in California. The remaining lines either had not been analyzed or could not be cost-effectively converted to conservation voltage regulation compliance.

The determination of whether a circuit is in compliance with the PUC order is not accomplished by formula and does not require that voltage regulation be applied religiously. That is, if most of the benefits of conservation voltage regulation are being achieved and the remainder would require significant capital investments, it appears that the PUC does not require additional action.

California utilities experienced energy savings from conservation voltage regulation between 1977 and 1985 at costs ranging from 0.10 to 3.78 cents per kilowatt-hour. The costs experienced by California utilities are reported in Table 8-57, by each of the participating utilities. The reported costs are determined by dividing cumulative nominal expenditures by cumulative savings (no discounting is used). Of course, as savings continue to accrue from capital investment made earlier, the cumulative costs per kilowatt-hour will continue to go down. These costs cannot be compared to the Council's costs without being modified to account for the value of future versus current energy savings. Making these modifications yields an average levelized costs of savings in nominal dollars from action taken in California between 1982 and 1985 of about 1.5 cents per kilowatt-hour, assuming the converted lines last 20 years and utilities' cost of money is 11 percent.

The California Energy Commission speculates that some of the costs included in the cost of energy savings really were spent on transmission and distribution efficiency improvements and should not have been counted against conservation voltage regulation costs. Assuming the savings from transmission and distribution efficiency improvements were not counted also, the costs of conservation voltage regulation savings would be lower than 1.5 cents per kilowatt-hour.

Costs to bring the circuit into compliance, based on costs in 1985, have averaged about $53,000 per feeder, with a range between $8,000 and $130,000. The $130,000 is the cost incurred on one long distribution feeder on PG&E's system and may well have included costs to reconductor the distribution feeder. Without the PG&E data point, the average is well below $50,000 per feeder.

Table 8-57
Costs of Energy Savings from Conservation Voltage Regulation in California
Years 1977-1985

Utility	Cost Cents per kWh
Pacific Gas and Electric	.44
Southern California Electric	.10
San Diego Gas and Electric	.69
Pacific Power and Light Company	1.12
Sierra Pacific Power Company	2.77
CP National	3.78

Source: California Energy Commission

As was indicated earlier, the costs in Table 8-57 are the total dollar cost divided by the cumulative savings of energy. As such, the costs will continue to go down, because the money has been spent and the savings will continue to accumulate each year. The higher costs indicated for Sierra Pacific and CP National probably are related to longer distribution feeder lines on the more rural systems of these utilities.

In 1985, the last year for which staff has data, California utilities saved 2.83 billion kilowatt-hours, or about 2 percent of their total load. This is equivalent to about 320 average megawatts.

Regional Experience of Pacific Northwest Utilities in Applying Conservation Voltage Regulation

Snohomish County Public Utility District is conducting a pilot program in conservation voltage regulation, initially on 12 circuits. The goals of the pilot are to 1) estimate the potential of conservation voltage regulation on Snohomish's system, 2) evaluate customer impact and acceptance of conservation voltage regulation, and 3) evaluate state-of-the-art conservation voltage regulation practices. If the pilot continues to show benefits, the utility plans to implement conservation voltage regulation on all of its applicable 12 kilovolt primary feeders. Future plans would possibly include upgrading primary feeders to 21.6 kilovolts or 34 kilovolts and implementing conservation voltage regulation on the upgraded lines.

Snohomish PUD's conservation voltage regulation target is to reach an average customer service voltage of about 117.5 volts compared to today's level of 123 volts.

The utility estimates that energy is being saved at a cost of about 5 to 7 mills per kilowatt-hour in nominal dollars. Most, if not all of the conservation voltage regulation conversions have been low cost and have achieved energy savings at very low levelized costs.

Snohomish PUD's schedule gives a sense of the preparation needed to do an effective job of implementing conservation voltage regulation. Before any conversions, one full year of data on each distribution feeder is required. The data is analyzed to determine whether any changes have to be made to the feeders in order that conservation voltage regulation can be most effective and to design the conservation voltage regulation strategy. Before conservation voltage regulation is implemented, some loads on certain feeders may have to be shifted to other feeders. Thus, the process takes about two years from the start of metering to the completion of engineering and implementation of the appropriate conservation voltage regulation strategy. New computer software could speed up the analysis of the data and the design of the conservation voltage reduction strategies.

Snohomish County Public Utility District currently is metering 24 additional feeders that were to be converted to conservation voltage regulation in June of 1990.[50] Forty-eight additional feeders will be metered beginning in the winter of 1991.

This lengthy preparatory period first was believed to be necessary for only the pilot phase of the project. However, experience has shown that conservation voltage regulation strategies specific to each line must be developed. Even with this extensive preparation, Snohomish PUD reports savings at about 5 to 7 mills per kilowatt-hour.

Conclusions: Conservation Voltage Regulation

The Council has included 100 megawatts of conservation voltage regulation in the resource portfolio at a cost of less than 2 cents per kilowatt-hour. The Council views this as a conservation resource. This may be a low estimate of achievable megawatts based on the California experience and estimates made by Battelle Northwest under contract to Bonneville. It would be difficult to identify at this time where the savings will be achieved. However, given the low cost of the resource, experiences elsewhere, and the probability that savings in California and Snohomish County can be duplicated on other utility systems, Council action to include this resource in its portfolio is prudent.

Relative to conservation voltage regulation, the Council has recommended the following activities:

1. All utilities should review the applicability of conservation voltage regulation on their distribution systems and implement it to the extent of their current expertise, if it appears to deliver cost-effective savings of electricity.

2. Because existing utility distribution systems are designed to 40-year old standards, the Council recommends that Bonneville coordinate a comprehensive study with utilities to consider whether there are appropriate design modifications for distribution systems that will deliver cost-effective energy savings. This activity seems prudent, in part because systems were designed

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50./ The status of those upgrades will be brought up to date in the final plan.

when electricity costs were much lower. The study should consider the interactions among conservation voltage regulation, efficiency improvements to the distribution system, efficiency improvements at end uses of electricity, and new electronic metering technologies. Electronic metering would provide utilities with considerably more information about loads than ever before and enable them to refine techniques and strategies to regulate voltage. The objective of this comprehensive study would be to determine net efficiency improvements that can be achieved without compromising operational flexibility or system reliability. Bonneville has contracted to review the Snohomish results for applicability to other utilities in its service territory. The contract deliverables could provide a starting point for the recommended study.

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Wind Power[51]

The Pacific Northwest is endowed with favorable wind resources, yet development of wind power in the Northwest has been limited because of the past surplus of generating capability and the availability of lower-cost resource alternatives. Beginning in the 1970s, many wind resource assessment programs and research projects were initiated in this region. Development of several commercial wind farms was attempted. But interest waned as the region's electrical surplus increased and federal support for renewable energy research declined. Wind technology of the early 1980s often could not cope with harsh environmental conditions at the region's better wind sites, leading to rapid deterioration and premature failure of many turbines, and the perception that wind was not a reliable electrical generating resource.

Based on the successful operation of several thousand wind machines in California, and the introduction of a new generation of heavy-duty machines, the Council's 1986 Power Plan found that commercially available and reliable wind power technology was available for use in the Pacific Northwest. Furthermore, the data collected by the Pacific Northwest Wind Energy Assessment Program suggested that the region has numerous promising wind resource areas, potentially capable of producing, in aggregate, 2,800 to 6,300 average megawatts of energy. But the estimated cost of energy from even the best areas was found to be more expensive than the cost of energy from the long-term marginal resource used in the 1986 Power Plan (new coal-fired power plants).

The Council, with the assistance of the Oregon Department of Energy, has re-examined the possible role of wind for supplying part of the future energy needs of the Pacific Northwest. Several factors led to this re-examination. First, the capital-related costs of wind farm development have declined since the 1986 Power Plan. This has lowered the estimated costs of wind-generated electricity. Secondly, the reliability of wind turbine generators has been better established since the 1986 Power Plan. Though large numbers of machines were in operation when the 1986 Power Plan was prepared, most of these machines were first-generation commercial machines of questionable reliability. Second-generation machines had only recently become available. Several years of operating experience have now been documented on several thousand second-generation machines and the reliability assumptions of the 1986 plan have been exceeded in practice. A third generation of machines promising improved reliability, cost-effectiveness, and efficiency is under development. Finally, the need for new resources, and the cost and availability of competing resources has changed. Fuel cost and availability, siting constraints,

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51./ Much of the background information and analysis in this section was taken from an issue paper prepared for the Council by Don Bain of the Oregon Department of Energy. This paper appeared as Council Staff Issue Paper #89-40 <u>Wind Resources</u>, October 16, 1989. The Northwest Power Planning Council appreciates the assistance it has received from the Oregon Department of Energy in support of the assessment of wind resources for this plan.

resource diversity policies, and environmental considerations limit the amount of fossil-fuel resources included in the Council's resource portfolio. These factors, combined with likely increases in future loads, have raised the cost of the marginal resources in the higher load growth cases. Wind power is now cost-effective in higher load growth cases.

Wind Power Technology

The technological evolution of wind turbine generators has been spurred by the rapid development of California wind resources during the last decade. California development started with only 7 megawatts of capacity installed in 1981. Today there are about 17,000 turbines totaling 1,500 megawatts of capacity in California, representing 90 to 95 percent of the world's installed wind capacity.

First-generation wind turbine generators of the early 1980s, largely of U.S. design, tended to be small-scale, lightweight designs based upon aerospace technology. A typical turbine was rated at 50 kilowatts and cost $2,200 per kilowatt installed. The aerodynamic stresses imposed upon these machines tended to be higher than expected, frequently resulting in poor reliability.

Second-generation machines, installed from the mid-1980s through the present, are largely of European design. These are medium-scale (100 to 250 kilowatts), heavyweight machines, whose conservative engineering largely overcame lack of understanding regarding structural and aerodynamic stresses. These designs have greatly improved reliability. The turnkey cost (of complete wind farms) in California is now about $1,000 per kilowatt. With periodic blade replacement and upgrades, these machines probably could operate for 15 to 20 years, but further improvements in technology may lead to early economic replacement.

A third generation of machines, currently being tested, uses improved understanding of aerodynamics to create more refined designs. Variable-speed operation is expected to improve energy capture and reduce fatigue loading. Larger machine sizes (150 to 600 kilowatts) should result in lower costs of production, installation and operation. These machines are expected to be less costly and more reliable than second-generation designs. Turnkey costs may decline to as low as $650 per kilowatt.

A major technical uncertainty in the Northwest is the ability of wind turbines to operate reliably under cold-climate conditions. The extensive wind resource areas of Montana, those with the greatest potential, are characterized by much colder winter conditions than the California wind resource areas. Winter is the season of peak winds at these Montana areas, and the season of the peak loads on the Northwest system, and so reliable turbine operation under cold conditions is important to the cost-effectiveness of wind power in Montana and high-elevation sites elsewhere in the region. Testing, and possibly refinement, of turbine designs for cold weather operation will be a prerequisite of commercial-scale development of Montana wind resources.

Wind Power Development Issues

Constraints associated with the development of wind power tend to be more technical than environmental in nature. With proper siting and design, the environmental effects of wind power development can be modest. But wind power is burdened by a history of questionable reliability. Moreover, wind power plants produce energy on an intermittent and as-available basis, impacting the value of wind power for some applications. Many of the best wind sites are remote from load centers, especially in the Pacific Northwest. Important issues, generally affecting the feasibility and cost-effectiveness of wind power development include system interconnection requirements, wind plant cost and performance, value of power, wind resource quality and environmental effects.

System Interconnection

Wind resource areas are often remote from load centers and from conventional generating plants as well. The development of such areas will require construction of transmission lines from the wind power stations to the existing electrical grid. These transmission interconnections must be sized to the installed capacity of the wind plant. Because the capacity factor of a wind power station located in even a good wind area is relatively low (25 to 35 percent) compared to a conventional thermal plant (60 to 80 percent), the cost of the transmission interconnection may be high on a per-unit-of-energy-produced basis.

Siting any transmission line is difficult and controversial. Because the largest wind resource areas of the Northwest lie east of the Continental Divide, the development of new transmission capacity to interconnect these areas with the west coast load centers will present the formidable difficulties of siting and construction through mountainous terrain near national parks, wilderness areas and other areas of high environmental quality.

Remote, large-scale wind power stations may adversely affect the power quality of nearby, interconnected power systems, unless properly designed. The fluctuating power output of a wind station may lead to voltage and frequency fluctuations on the local power system, particularly if the interconnection to the main grid is weak. Additionally, the induction generators used in many wind turbines produce a large reactive power load[52] that may have to be controlled by installation of short capacitors or other reactive compensation at or near the wind power station switchyard. The variable blade-spaced synchronous generation wind turbines now under development may alleviate the problem of reactive load.

Additional discussion of system interconnection issues is provided in a recent Bonneville Power Administration study of wind power system interconnection issues (Bonneville, 1989)

52./ Reactive power is the power that is used to magnitize the electrical windings of rotating electrical machinery and adjacent conductors of alternating current power lines. This power does not produce useful work, but nevertheless has to be transferred between reactive sources and reactive loads.

Wind Plant Cost and Performance

The historical performance of wind power plants in the Northwest has not been good. Low capacity factors and premature machine failures were the norm, not the exception. The most prominent Northwest wind project--the Goodnoe Hills MOD-2 turbine project--was dismantled following termination of federal funding. Few understood that this was largely intended as an experimental pilot project and not a commercial demonstration.

Despite the greatly improved performance of contemporary turbine designs demonstrated by more recent commercial wind power developments in California, the image of wind power technology remains poor in the Northwest. Demonstrations within the region of the cost and performance of contemporary wind machines using contemporary site design may be required to confirm the cost and performance of this technology. Perhaps a more important issue, going beyond image, is the ability of contemporary wind power technology to perform reliably and cost-effectively in the harsh environment of the Rocky Mountain Front and high-elevation wind resource areas of the Northwest. Testing and, likely retirement, of contemporary turbine designs in this environment is needed before large-scale development of the wind resources of these areas can commence.

Seasonality and Intermittence of Wind Power

Wind power is an intermittently-produced resource. Energy production varies hourly, seasonally and, to a lesser extent, annually. For the storm-driven wind resources of the Pacific Northwest, it is not readily predictable on a short (hourly or daily) time scale.

Wind energy must be used, stored, curtailed or dumped. It cannot be called upon if the wind is not blowing. The intermittent character of wind potentially lowers the value of the power produced by a wind power station, in comparison with the dispatchable output of most conventional generating plants. Wind power plants may not garner the capacity credit of dispatchable plants, and the value of electricity from wind energy may be less if its production is not coincident with load requirements.

These problems tend to be less significant when wind represents a small portion of the total generating capacity of the system. These problems may surface as the contribution of wind-powered energy increases. However, the increasing diversity of larger and more widespread wind power developments may overcome the intermittent nature of specific wind resource sites. Load/resource coincidence also can be improved by selecting wind sites for development that have winds more coincident with system loads. For example, Rocky Mountain Front winds are winter-peaking, seasonally coincident with regional loads (see Bonneville, 1989).

Further discussion of these issues is provided in Bonneville, 1989.

Resource Quality

The potential energy available from the wind is a function of the cube of the wind speed. Project economics, therefore, are very sensitive to small errors in the assessment of the wind resource. Good wind resource data, therefore, is extremely important in preparing accurate assessments of the availability and cost-effectiveness of wind power and in the design of wind projects. Important wind resource characteristics include average wind speed, seasonal and interannual variation, shear and turbulence. The spatial extent of good quality winds is important in estimating the potential of this resource. This resource information should be available prior to proceeding with wind power development.

Environmental Effects

The environmental impacts of wind energy usually are few. But, negative impacts have occurred in California and could occur in the Pacific Northwest if projects are not properly sited and designed. The principal environmental concerns regarding wind resource development are noise, visual impacts, construction impacts and bird collisions.

Noise

The interaction of wind turbine blades with air flow may produce noise. Also, for towers designed with downwind blades, the wake caused by the tower can interact with the blades, causing a periodic thump. If the blades are upwind of the tower the thump is minimal or inaudible. Noise levels are strongly influenced by turbulence, atmospheric boundary layers, wind direction, terrain, blade shape, and turbine design. Therefore, tests of a turbine's noise level at one site under certain conditions is of little predictive value at other sites with different wind conditions. Research is being conducted to design turbine blades that are quieter than current blades.

Noise has been a problem when turbines are sited close to residences. Typical solutions have been to require turbines to be set back from residences and other sensitive land uses and to conduct periodic noise surveys. The potential for noise problems is low at most promising Pacific Northwest sites due to their remoteness.

Visual Impacts

Visual impacts are possible where turbines are sited near scenic areas. While some scenic areas, such as the Columbia River Gorge, are officially recognized as scenic, beauty is still in the eye of the beholder--a visual problem could occur anywhere. Unfortunately, good winds tend to occur in exposed and visually-obtrusive locations, such as along ridgelines. Moreover, average wind speed tends to increase with height--hence the use of tall, visually obtrusive towers for wind turbines.

In the Pacific Northwest, coastal and Columbia River Gorge wind resource areas have high potential for visual conflicts. The potential for aesthetic conflicts at the better Pacific Northwest wind resource areas is shown in Table 8-58.

Table 8-58
Wind Resource Area Development Issues

State - Area	Access Problems	Trees	Icing & Snow	County Regulation[a]	More Wind Data Needed	Visual Impacts	Envir. Impacts	Gorge Constraints[b]
Idaho								
Albion Butte	Y	N	Y	N	Y		Y	N
Bennett Peak	Y	N	Y	N	Y	pot	Y	N
Duncan Mtn	Y	N	Y	N	Y		unk	N
Strevell	N	N	Y	N	Y	pot	unk	N
Montana								
Blackfoot Area	N	N	N	N	Y		unk	N
Great Falls	N	N	N	N	Y		unk	N
Livingston	N	N	N	N	Y		unk	N
Sieban 1	Y	N	Y	N	Y		unk	N
Sieban 2	N	N	N	N	Y		unk	N
Nevada								
Pequop Summit	Y	N	Y	N	Y		unk	N
Wells W	N	N	N	N	N		unk	N
Oregon								
Adel	N	N	N	N	Y		unk	N
Burns Butte	N	N	N	N			unk	N
Cape Blanco	N	N	N	N	N	pot	Y	N
Cascade Locks	N	Y	Y	N	N	pot	unk	Y
Coyote Hills	N	N	N	N	Y		unk	N
Florence Jetty	N	N	N	N	Y	pot	Y	N
Gold Beach Area	N	Y	N	N	N		unk	N
Hampton Butte	N	N	N	N	Y		unk	N
Klondike	N	N	Y	N	Y	pot	unk	N
Langlois	N	N	N	N	Y	pot	Y	N
Langlois Mtn	N	Y	N	N	Y		unk	N
Prairie Mtn.	N	Y	N	N	Y		unk	N
Pueblo/Steens	Y	N	N	N	Y		unk	N
Pyle Canyon	N	N	N	N	Y		unk	N
Sevenmile Hill	N	unk	N	Y	N	pot	unk	Y
Winter Ridge	Y	N	N	N	Y		unk	N

Table 8-58 (cont.)
Wind Resource Area Development Issues

State - Area	Access Problems	Trees	Icing & Snow	County Regulation[a]	More Wind Data Needed	Visual Impacts	Envir. Impacts	Gorge Constraints[b]
Washington								
Beezley Hills	N	N	N	N	Y		unk	N
Boylston Mtn	N	N	N	N	Y		unk	N
Burdoin Mtn	N	N	N	N	Y	pot	unk	Y
Cape Flattery	N	Y	N	N	Y		unk	N
Columbia Hills E	Y	N	N	N	N		unk	N
Columbia Hills W	Y	N	N	N	Y	pot	unk	Y
Goodnoe Hills	N	N	Y	N	N		unk	N
Horse Heaven	N	N	N	N	Y		unk	N
Kittitas Valley E	N	N	N	N	N		unk	N
Murdock Area	N	N	N	N	Y	pot	unk	Y
Rattlesnake Mtn	N	N	N	N	Y		unk	N
Roosevelt	Y	N	N	N	Y		unk	N
Tule Hills	N	N	N	N	Y		unk	N

Notes

Y = yes, N = no   unk = unknown   pot = potential, the issue has been raised

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a Other regulation may apply. Oregon sites would be covered by statewide wind energy siting standards if the project were 25 megawatts, or greater, in size by the same developer. Montana's statewide environmental standards generally would apply to all Montana sites. If a BPA transmission line extension were required, a federal EIS generally would apply.

b Columbia River Gorge scenic restrictions.

Visual conflicts can be controlled by turbine layouts, tower heights, and transmission line routing that minimize visual intrusion from heavily traveled corridors and popular locations. Wind power development may have to be prohibited in sensitive areas. Unobtrusive turbine colors commonly are required in California.

Site Development Impacts

A wind farm requires construction of roads, turbine pads, electrical lines and maintenance facilities. The amount of land disturbed as a percentage of the total area is small, about 2 to 5 percent, and many prior land uses, for example, grazing, can continue during wind farm operation. Nevertheless, construction must be sensitive to wildlife, erosion control and water quality impacts. Because the site is windy, retention of topsoil may require special measures.

Bird Collisions

Collisions between birds and wind turbine towers and blades is possible. Monitoring at several operating wind farms has shown that mortality is low. But, special attention is needed when siting projects near places with endangered species, along migratory paths, and in areas of dense bird populations.

Wind Power Potential in the Pacific Northwest

This analysis of wind power potential in the Pacific Northwest is based on wind resource information compiled in a Bonneville Power Administration study of regional wind resource characteristics (Baker, 1985). The cost of energy and total energy production potential of each of the most promising resource areas identified in the Bonneville study were estimated using the cost and performance characteristics of contemporary wind machines. The effects of possible constraints to the full development of each of these areas were assessed on the cost and availability of energy from the area. These final estimates of energy cost and availability determined the Northwest wind resource potential for this plan.

Promising Wind Resource Areas

Oregon State University was hired by Bonneville to carry out a regionwide resource assessment program to identify and measure high-velocity-wind sites in Oregon, Washington, Idaho, Western Montana, and Northwest Nevada (Baker, 1985). This program identified 118 sites with annual average wind speeds of at least 12 miles per hour. Of these sites, 40 were identified as meriting further study (see Figure 8-51).

Characteristics that must be considered in the assessment of the potential of a wind resource area include wind speed and direction, interannual variation, shear, turbulence, seasonality and spatial extent. Average wind speeds are crucial to the cost and quantity of wind-generated energy. The amount of energy in the wind rises with the cube of the speed. Because wind turbines only can capture a portion of this energy, the annual energy generated by a turbine approximately rises with the square of the annual average wind speed. Thus, small differences in average wind speeds cause large differences in electric generation. Because turbines are capital-intensive, project cost-effectiveness is very sensitive to the strength of the wind resource. For these reasons, most wind energy researchers do not consider sites with annual average winds below 12 miles per hour, measured up to a 100 yards above the ground. Good sites have average speeds of 14 to 16 miles per hour. The average wind speeds of the 40 promising wind resource areas identified in the Oregon State University study are shown in Table 8-59.

Wind Resources

Figure 8-51
Pacific Northwest Wind Resources

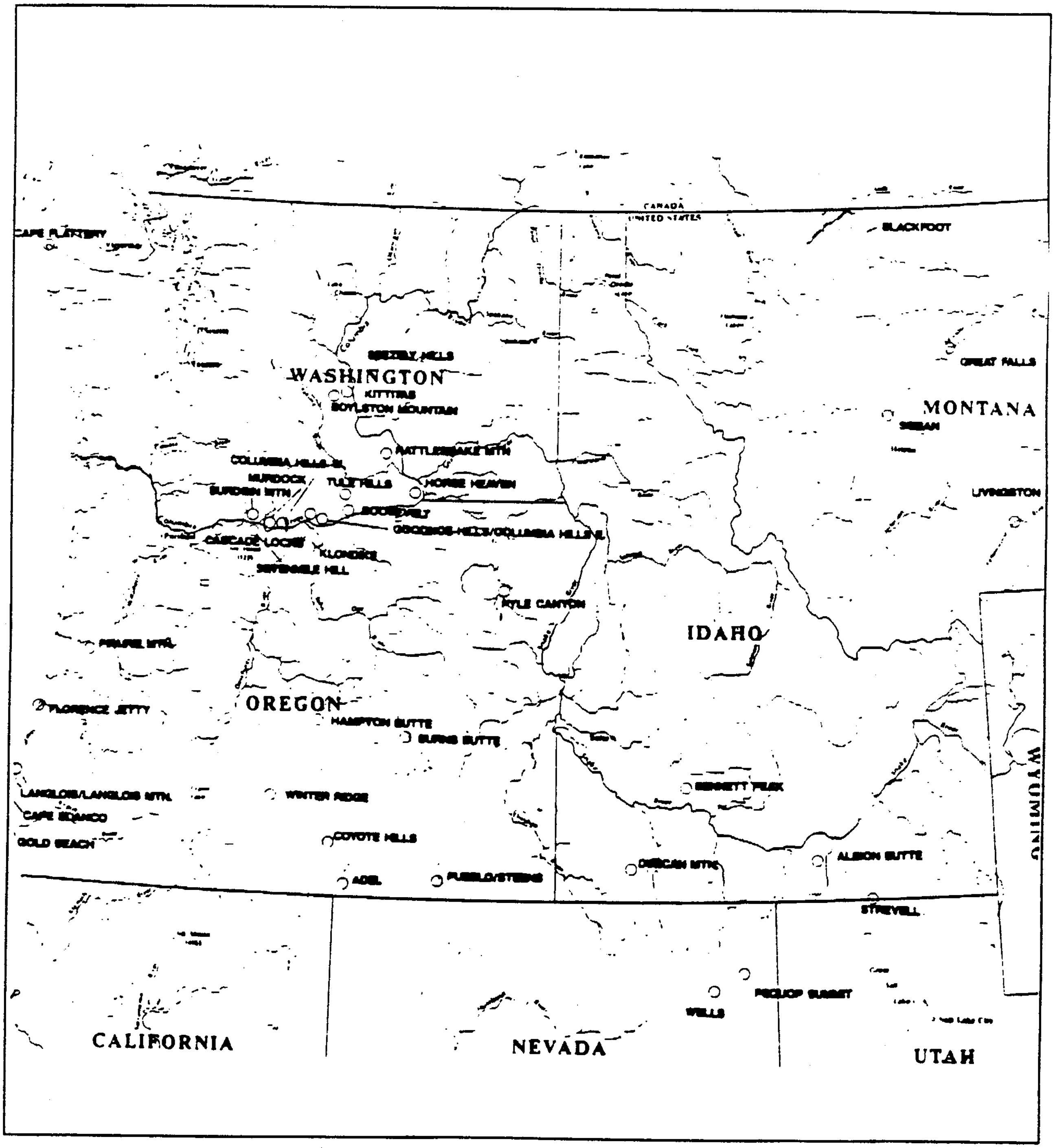

Table 8-59
Wind Resource Area Wind Measurements

State - Area	Type[a]	Elev MSL[b]	Speed (mph)[c]	Shear[d]	Data Confidence[e]	Data Type[f]	Peak Seasons[g]
Idaho							
Albion Butte	RC	7,110	17	.10	B	MO	Fall
Bennett Peak	RD	7,440	16	.14	L	HR	Winter
Duncan Mountain	F	6,240	11.6	.14	B	HR	Spring
Strevell	F	5,276	12.7	.14	B	MO	Winter
Montana							
Blackfoot Area 1	F	4,875	17	.12	B	MO	Winter
Blackfoot Area 2	F	4,500	15	.12	B	MO	Winter
Blackfoot Area 3	F	4,920	13	.12	B	MO	Winter
Great Falls	F	3,688	14.4	.14	B	MO	Winter
Livingston	F	4,632	15.5	.07	E	HR	Winter
Sieban 1	F	6,507	16	.07	B	HR	Winter
Sieban 2	F	4,882	13.5	.07	B	MO	Winter-Spring
Nevada							
Pequop Summit	RC	7,540	15	.07	B	HR	Winter
Wells W	F	5,960	12.5	.07	B	MO	Winter-Spring
Oregon							
Adel	RC	6,571	14.5	.14	B	HR	Winter-Spring
Burns Butte	RC	5,307	13	.07	B	MO	Spring
Cape Blanco	F	217	12.5	.20	E	MO	Winter
Cascade Locks	F	100	15	.14	B	HR	Winter
Coyote Hills	F	6,367	15.6	.10	B	MO	Spring
Florence Jetty	F	13	12.1	.14	B	HR	Summer
Gold Beach Area	RC	720	12.5	.07	B	MO	Winter
Hampton Butte	RC	6,344	15.2	.10	B	HR	Winter-Spring
Klondike 1	F	1,540	14	.14	B	MO	Spring-Summer
Klondike 2	F	1,200	12	.14	B	MO	Spring-Summer
Langlois	F	20	12	.10	L	MO	Winter
Langlois Mountain	RC	1,120	14	.07	B	HR	Winter
Prairie Mountain	RC	3,200	14.3	.07	B	HR	Fall-Winter

Table 8-59 (cont.)
Wind Resource Area Wind Measurements

State - Area	Type[a]	Elev MSL[b]	Speed (mph)[c]	Shear[d]	Data Confidence[e]	Data Type[f]	Peak Seasons[g]
Oregon (cont.)							
Pueblo/Steens	RC	7,000	17	.14	L	MO	Winter-Spring
Pyle Canyon	F	3,860	11.4	.10	B	MO	Winter
Sevenmile Hill	F	1,880	15.3	.12	E	HR	Summer
Upper Pyle Canyon	F	3,660	13.4	.10	B	HR	Winter
Winter Ridge	RC	7,060	14.9	.20	B	HR	Winter
Washington							
Beezley Hills	RD	2,600	13	.07	E	HR	Spring-Summer
Boylston Mountain	RD	2,400	12	.07	B	HR	Spring-Summer
Burdoin Mountain	F	2,000	12	.07	B	HR	Summer
Cape Flattery	RC	1,000	16	.14	B	MO	Winter
Columbia Hills W.	RD	2,500	14.3	.07	B	HR	Spring-Summer
Columbia Hills E. 1	RD	2,800	18	.08	E	HR	Spring-Summer
Columbia Hills E. 2	RD	2,600	15.4	.08	E	HR	Spring-Summer
Goodnoe Hills	F	2,640	14	.22	E	HR	Spring-Summer
Horse Heaven	RC	2,200	13.4	.20	B	HR	Winter-Spring
Kittitas Valley E.	F	2,660	11.9	.13	E	HR	Spring-Summer
Murdock Area	F	400	13	.14	B	HR	Summer
Rattlesnake Mtn 1	RC	3,400	18	.07	B	HR	Winter-Spring
Rattlesnake Mtn 2	RD	3,000	13	.07	B	HR	Spring
Roosevelt	F	1,706	13.8	.07	B	HR	Summer
Tule Hills	F	2,750	12.3	.14	B	HR	Winter

Primary Reference: Baker, R.W., et. al., 1985. Pacific Northwest Wind Regional Energy Assessment Program, BPA 85-19. Prepared by Oregon State University for the Bonneville Power Administration, Portland, Oregon, October 1985.

a Type: F = Flat or rolling terrain, RD = Ridgeline Downwind, RC = Ridgeline Crosswind
b Feet elevation. Will vary within the site area, depending on terrain and distance from measurement site.
c Average annual speed at 50 feet height.
d A coefficient that is used to estimate winds at other heights.
e Data Confidence: E = Extensive, B = Broad, L = Limited
f Date Type: HR = Hourly, MO = Monthly
g The season(s) when potential electric generation peaks.

Wind data describing the distribution of wind speed over time is required to calculate accurately the energy production of a given turbine. Wind speed distributions are not available for most regional sites. Generalized "Rayleigh" wind speed distributions are used instead, except for twelve sites with better measurements.

The energy production potential of wind is sensitive to elevation as well as wind speed. Low elevation sites with denser air have greater energy potential than higher-elevation sites of similar area and wind speed characteristics. Most wind resource areas are not flat, but have a range of elevations. The range of elevations is unknown for the Northwest's wind resource areas so the elevation at the anemometer tower was used. This is a reasonable representation since the measurement sites usually are near the highest elevation within the area. The elevation at the anemomometer tower appears in Table 8-59 for each area.

Representative Wind Power Plants

The energy produced by a wind turbine is a function of turbine design and reliability as well as wind resource characteristics. One representative, commercially available turbine design was selected for use in this assessment. This design was the least-costly of five commercially available designs evaluated for this study. The costs of energy using the five turbine designs were calculated for eleven of the region's windiest sites. No single turbine was found to be least-costly at all sites. The performance curve of the turbine that was least-costly at the majority of the eleven sites was used to estimate the regional potential.

The availability of a turbine is a function of scheduled maintenance outages and unexpected machine failures. Turbine availability at California wind projects is monitored by the Electric Power Research Institute. In a large sample the average availability was 89 percent. Some wind farms maintain a consistently high availability of 98 percent. Others were as low as 63 percent. The more reliable California projects have achieved and exceed 95 percent for the last four years. Low availability may indicate inadequate maintenance programs and poorly designed turbines. Projects with good availability have reliable turbines, on-site spare part inventories and repair crews, and constant monitoring of operations. A 95 percent turbine availability was assumed for this plan.

Estimates of wind power capital costs include siting and licensing costs, turbine costs, balance-of-plant costs, transmission grid interconnection costs, road access costs and site decommissioning. Land costs were not included as capital costs since conventional practice is not for a developer to purchase the land, but rather to pay a royalty for the wind rights.

Wind farms can now be installed for than $1,000 per kilowatt, and costs are expected to decline as more refined turbine designs are introduced. For this plan, the delivered cost of a turbine was estimated to be $842 per kilowatt. This includes the extra costs of extended warranties. Balance-of-plant costs include turbine installation, civil improvements, in-farm electrical collection system, interconnection equipment and contingencies. Balance-of-plant costs of 20 percent are assumed and are based on experience in the hilly Tehachapi area in California. Adding balance-of-plant costs of $165 per kilowatt yields total wind farm construction costs of $1,007 per kilowatt.

Siting and licensing costs were estimated to be about 1.5 percent of wind farm construction costs ($15 per kilowatt). This includes the costs of micrositing studies, but assumes that basic site wind resource information is available.

Other capital costs include transmission interconnection costs, road access costs and the costs of a site decommissioning fund. Transmission interconnection costs were estimated to be $0.75 per kilowatt per mile of transmission line. The distance to the nearest substation was used for estimating the transmission interconnection costs for each wind resource area except for the Blackfoot areas. Because of the weak transmission grid in the Blackfoot area and the size of this resource, the distance from Browning to Great Falls was used to estimate interconnection costs. Road access costs were assumed to be $10 per kilowatt for all sites. The cost of establishing a site decommissioning fund was estimated to be $10 per kilowatt for all sites.

Capital-related costs were increased by 5 percent for areas having challenging environmental conditions, including cold climate areas east of the Continental Divide, high-elevation sites (5,000 feet, or greater) subject to clear icing, and coastal sites subject to accelerated corrosion. The resulting estimates of wind farm development costs ranged from $1,017 per kilowatt at the Klondike area near the Columbia River Gorge to $1,104 per kilowatt at the Duncan Mountain area in southwestern Idaho.

Operation and maintenance costs include routine turbine inspections, blade cleaning, and lubrication. Operation and maintenance and replacement costs at California projects are 0.5 to 1.7 cents per kilowatt hour, averaging about 1.0 cent per kilowatt hour (Lynette, R., et. al, 1989). Operation and maintenance costs of 1.1 cents per kilowatt-hour, excluding post-operational capital replacement costs (see below), were assumed. Environmental conditions at many Northwest wind resource areas are far more severe than at the California sites. Testimony provided to the Council suggested that operation and maintenance costs likely would be greater for Northwest wind resource areas, particularly for cold-climate areas, coastal areas subject to accelerated corrosion and areas subject to severe snow or icing conditions. Costs in areas having severe environmental conditions were increased by 5 percent over the base operation-and-maintenance cost of 1.1 cents per kilowatt-hour.

A minimum of one year, and preferably more, of basic wind resource data is required to identify a wind site. This data is assumed to be available prior to the initiation of siting studies for specific wind projects. A developer will follow up the basic measurements with a micrositing study to determine turbine layout. A period of 24 months is required to complete micrositing, engineering, and permitting. Turbine orders would be placed during the second year of siting and licensing activity. Site development and turbine installation for a typical commercial-scale project (30 megawatts, for example) can be completed in 12 months. For planning purposes, "construction period" begins with major equipment order, therefore, for this plan, a siting and licensing period of 12 months and a construction period of 24 months is assumed.

This plan assumes that a wind project will operate for 40 years. Continued reliable operation for this period will require periodic overhaul or replacement of major turbine components. Wind turbine experts submitted to the Council a long-term turbine maintenance and component replacement schedule that could be expected to secure reliable operation for 40 years. This schedule (see Table 8-60) would require post-operational capital replacement expenditures averaging $14.90 per kilowatt per year. Costs in areas having severe environmental conditions were assumed to be 5 percent greater.

Table 8-60
Estimated Interim Capital Replacement Costs[a]
For a 200 to 300 kilowatt machine (assume 250 kilowatt)

Year	(1989 $/thousands)[b]	Item
1	$0	
2	$0	
3	$0	
5	$0	
6	$0	
7	$4	Overhaul yaw gear
8	$0	
9	$0	
10	$0	
11	$15	Overhaul gearbox; replace droop cable
12	$5	Rewind generator; replace bearings
13	$26	Replace bladeset
14	$4	Overhaul yaw gear
15	$0	
16	$0	
17	$0	
18	$0	
19	$0	
20	$22	Replace gearbox and droop cable
21	$23	Replace yaw bearing, bears and pitch bearings
22	$0	
23	$0	
24	$5	Rewind generator; replace bearings
25	$5	Refurbish tower; replace bolts
26	$26	Replace bladeset
27	$0	
28	$4	Overhaul yaw gear
29	$0	
30	$0	
31	$15	Overhaul gearbox; replace droop cable
32	$0	
33	$0	
34	$0	
35	$5	Rewind generator; replace bearings
36	$4	Overhaul yaw gear
37	$0	
38	$0	
39	$0	
40	$0	

a From Robert Lynette letter of January 4, 1990 and phone conversation with Dan Seligman of March 23, 1990.
b Discounted to 1988 dollars, using factor of 0.95.

Cost and performance assumptions for the base case representative wind power project are shown in Table 8-61.

Table 8-61
Cost and Performance Characteristics of a Representative Wind Power Station
(1988 Dollars)

	Representative Wind Power Station[a]
Plant Configuration	150 to 200kW Units
Machine Type	Horizontal Axis, 82 foot diameter blades
Rated Capacity (MW/unit)	0.25
Peak Capacity (MW/unit)	Not Available
Equivalent Annual Availability (%)	95%
Siting and Licensing Cost ($/kW)	$15
S&L Hold Cost ($/kW/yr.)	$4.00
Construction Cost ($/kW)[b]	$1,007
Fixed O&M Cost ($/kW/yr.)	$0.00
Variable O&M Cost (mills/kWh)	11.0
Post-op Capital Replacement Cost[c]	$14.90
Wind Rights Royalty	7% of Total Energy Costs
Siting and Licensing Lead Time (months)	24
Construction Lead Time (months)	12
Service Life (years)	40

a Base costs are shown, costs were adjusted to account for specific environmental conditions. See text.
b "Overnight" cost (excludes interest during construction).
c Includes site decommissioning fund.

Reference Energy Cost Estimates

The annual energy production per unit of installed capacity was estimated for each area using turbine capacity factors derived as described above and applying an in-farm electric loss factor of 2 percent. The resulting net capacity factor is shown for each site in Table 8-62. Levelized energy production costs were calculated using the capital, operation and maintenance and post-operational capital costs described earlier and the reference financial and other assumptions described in the introduction to this chapter. Land rent royalties add another five percent to the cost of energy. The resulting levelized energy costs range from 7.4 cents per kilowatt-hour for the Columbia Hills East area to 17.3 cents per kilowatt-hour for the Duncan Mountain area (see Table 8-62).

Wind Resource Potential

The wind-generated electricity potential available to the region was based on the number of turbines that could be sited in each of the wind resource areas and the expected energy production of each turbine. The number of turbines that could be sited in each area multiplied by the capacity of the representative turbine used in this assessment yielded the potential capacity at each area. Multiplying this installed capacity by the net capacity factor calculated earlier yielded an estimate of the technical energy production potential of each area. But land use, transmission and other constraints will limit the amount of wind energy that could be obtained from each wind resource area. The developable potential was estimated by considering the likely effects of possible constraints to wind power development at each resource area.

Technical Resource Potential

The spatial extent of each wind resource area (see Table 8-62) was estimated during the regional energy resource assessment program (Baker, et al., 1985). Local topography, trees, competing land uses, and natural features such as lakes reduce the developable land area of each resource area. The usable portion of each area (see Table 8-62) was subjectively estimated given limited knowledge of the sites and a review of U.S. Geologic Survey topographic maps. These estimates are very preliminary, and further research could change the percentages considerably.

Wind farms were assumed to be laid out according to terrain type. Linear arrays of one to three rows of turbines were assumed for ridgelines and deeper arrays for plains (Tables 8-59 and 8-62). Conservative spacing of 10 rotor diameters (820 feet) downwind and 5 rotor diameters crosswind was assumed for minimizing wake losses. Multiple rows are offset. Spacing was determined by the available wind direction data. Closer spacing yields more turbines per site but with possible performance penalties because of wake interference. Optimal layout at these wind resource areas would require additional site data and micrositing studies.

The resulting estimates of wind energy technical potential at the 46 wind resource areas is shown in Table 8-62. Nearly 19,000 megawatts of turbine capacity could be installed, generating about 4,500 average megawatts. More than 94,500 of the 200-kilowatt turbines would be required for full development of this capacity.

Table 8-62
Regional Wind Potential and Site Cost-effectiveness

State-Area	Spatial Extent[a]	Usable Portion (%)	Array Layout[b]	Number of WTG[c]	Installed Capacity (MW)	Capacity Factor[c] (%)	Technical MW	Potential[f] MWa/yr.	Cents /kWh[e]
Idaho									
Albion Butte	13	50	2R-10X	84	16.8	25.4	16.5	4.1	10.1
Bennett Peak	8	40	1R-10X	21	4.2	25.9	4.1	1.1	10.0
Duncan Mountain	90	60	8X10	2,970	594.0	14.3	582	83	17.3
Strevell	8	60	8X10	251	50.2	17.7	49	8.6	13.9
Montana									
Blackfoot Area 1	1500	50	10X10	35,588	7,117.6	30.4	7,030	2,100	9.3
Blackfoot Area 2	750	50	10X10	17,763	3,552.6	25.2	3,480	870	11.0
Blackfoot Area 3	1000	50	10X10	23,853	4,770.6	19.2	4,680	890	14.0
Great Falls	75	60	8X10	2,484	496.8	24.5	490	120	10.4
Livingston	25	80	8X10	1,092	218.4	24.9	210	53	10.4
Sieban 1	15	40	5X10	490	98.0	24.6	96	23	10.4
Sieban 2	35	40	5X10	1,170	234.0	18.5	230	42	13.4
Nevada									
Pequop Summit	8	40	1R-5X	41	8.2	21.1	8.0	1.7	11.9
Wells W	4	40	8X10	84	16.8	14.8	17	2.4	16.4
Oregon									
Adel	14	80	3R-10X	216	43.2	22.3	42	9.4	11.3
Burns Butte	8	50	1R-10X	26	5.2	16.7	5.1	0.8	14.7
Cape Blanco	2.5	50	8X10	66	13.2	23.2	13.0	3.0	11.2
Cascade Locks	1.2	10	1R-10X	1	.2	30.4	0.2	0.1	8.4
Coyote Hills	5	50	8X10	128	25.6	24.5	25	6.1	10.6
Florence Jetty	2	60	2R-10X	16	3.2	19.1	3.1	0.6	13.0
Gold Beach Area	3	50	1R-10X	10	2.0	18.0	2.0	0.4	13.7
Hampton Butte	4	50	1R-10X	13	2.6	23.5	2.5	0.6	10.9
Klondike 1	15	40	8X10	324	64.8	25.1	64	16	9.7
Klondike 2	200	40	8X10	4,475	895.0	18.0	880	160	13.0
Langlois	4	70	8X10	147	29.4	17.6	29	5.0	14.0
Langlois Mtn	3.5	60	1R-5X	27	5.4	23.1	5.3	1.2	11.0

Table 8-62 (cont.)
Regional Wind Potential and Site Cost-effectiveness

State-Area	Spatial Extent[a]	Usable Portion (%)	Array Layout[b]	Number of WTG[c]	Installed Capacity (MW)	Capacity Factor[d] (%)	Technical MW	Potential[f] MWa/yr.	Cents /kWh[e]
Oregon (cont.)									
Prairie Mountain	4	30	1R-10X	8	1.6	22.3	1.6	.3	10.9
Pueblo/Steens	18	40	1R-5X	93	18.6	29.0	18	5.2	9.0
Pyle Canyon	12	40	8X10	259	51.8	15.1		7.6	15.3
Sevenmile Hill	3	60	5X10	139	27.8	28.4	27	7.7	8.7
Upper Pyle Canyon	6	50	8X10	162	32.4	20.9	32	6.6	11.4
Winter Ridge	27	70	3R-8X	456	91.2	24.9	89	22	10.4
Washington									
Beezley Hills	17	60	3R-10X	197	39.4	18.4	39	7.1	12.8
Boylston Mountain	8	60	1R-8X	38	7.6	15.2	7.4	1.1	15.4
Burdoin Mountain	3	50	5X10	116	23.2	15.4	23	3.5	15.0
Cape Flattery	13	40	2R-5X	134	26.8	32.9	26	8.6	8.1
Columbia Hills E 1	4	60	2R-10X	31	6.2	34.8	6	2.1	7.4
Columbia Hills E 2	7	60	2R-10X	54	10.8	26.9	11	2.8	9.2
Columbia Hills W	20	60	1R-10X	77	15.4	23.0	15	3.4	10.5
Goodnoe Hills	1.5	60	5X10	72	14.4	27.1	14	3.8	9.2
Horse Heaven	34	40	2R-5X	350	70.0	24.2	69	17	10.1
Kittitas Valley E	12	60	8X10	389	77.8	17.3	76	13	13.6
Murdock Area	5	50	5X10	196	39.2	22.3	38	8.5	10.8
Rattlesnake Mountain 1	16	50	2R-8X	129	25.8	33.7	25	8.4	7.6
Rattlesnake Mountain 2	7	50	2R-10X	45	9.0	18.2	9	1.6	13.0
Roosevelt	2	50	5X10	77	15.4	21.8	15	3.3	11.0
Tule Hills	6	60	10X10	162	32.4	18.0	32	5.7	13.4

Notes

a Miles: Square miles gross site area or miles of ridgeline.
b Ridgelines: Number of turbine rows, number of rotor diameters spacing. Other sites: Number of rotor diameters spacing across and downwind. See Table 8-59 "Type" column to determine terrain.
c Number of WTG: Net number of 200 kilowatt, 82 foot diameter wind turbine generators.
d CF: Capacity Factor is net of turbine availability, elevation and in-farm electric losses. Due to wide spacing, zero wake losses are used.
e Cost of energy is levelized nominal dollars for 1988 in-service.
f At switchyard busbar.

Achievable Potential

The Council includes in its resource portfolio only resources that it is confident could be developed within the 20-year period of the plan. Because of transmission constraints, system integration uncertainties, land-use conflicts and uncertainties, severe winter climate conditions, and other potential constraints, only a fraction of the technical potential shown in Table 8-62 appears to be developable at this time.

The three Blackfeet wind resource areas encompass much of the Blackfeet Indian Reservation in north central Montana. Because of the large size of the Blackfeet area resources, and the limited transmission service to that part of Montana, it is unlikely that the existing transmission network would be capable of supporting significant development of that resource. The large size of the Blackfeet area resource, coupled with the intermittent nature of wind would likely require that the output be transmitted to the main portion of the regional grid. But this would require transmission south to the Great Falls area, then west to regional load centers. Detailed analysis of the resulting transmission requirements has not been done, but the resulting transmission distance would likely render the Blackfeet resource uneconomical to develop.

A portion of the Blackfeet area resource, however, might be accommodated by new transmission capacity south to the Great Falls area or west to the Missoula area. Transmission west probably would be limited to one 69 or 115 kilovolt line because of the narrow and environmentally sensitive corridor between Glacier National Park and the Great Bear Wilderness. Transmission to the Great Falls area likely would be limited by the ability of the transmission grid at Great Falls to absorb intermittent wind power.

For purposes of this assessment, we have assumed that 150 megawatts of Blackfeet area wind capacity could be accommodated on a new 115 kilovolt line west to the Missoula area. We have also assumed that 300 additional megawatts of capacity could be accommodated on the existing grid at Great Falls. This would require a single 230 kilovolt line from the Blackfeet area to Great Falls. (A rough estimate of the cost of this transmission is included in the energy cost estimates of Table 8-61.)

For this reason, we have limited the estimated potential from the Blackfeet area to 450 megawatts of capacity, capable of producing about 140 megawatts of energy. This level of development would occupy slightly more than 1 percent of the land area at the reservation. Further, investigation of transmission and system integration of Montana wind resources should allow this estimate to be further refined.

Aesthetic sensitivities will constrain the availability of wind resources further. To account for these constraints, the potential contribution of land lying within the boundaries of the Columbia River Gorge Scenic Area was omitted from the estimate of achievable potential.

Current wind turbine technology appears to be capable of operating reliably at most Northwest wind resource areas, though design and maintenance adaptations likely will be required for sites with extreme winter cold and sites exposed to corrosive maritime air. But some sites have severe wintertime icing and snow problems (see Table 8-58). Because the effect of severe icing and snow on turbine reliability is not well understood, sites known to have these problems were omitted from the estimates of availability.

Considering the technical wind power potential in the region, the estimated cost of power from the region's wind resource areas and system integration, aesthetic and climate constraints to development, the Council estimates that 450 megawatts of wind-generated energy could be obtained by the development of about 1,500 megawatts of wind project capacity. The cost of this energy is estimated to range from 7.4 to 13.6 cents per kilowatt-hour, excluding credits or penalties resulting from factors such as seasonality, wind variability or leadtime. The supply curve for this energy is shown in Table 8-63.

Table 8-63
Pacific Northwest Wind Resource Potential
Available for Development

Wind Resource Area	Capacity (MW)	Energy (MWa)	Levelized Energy Cost (cents/kWh)
Columbia Hills East 1	6	2	7.4
Rattlesnake Mountain 1	26	9	7.6
Cape Flattery	13	4	8.1
Sevenmile Hill	7	2	8.7
Pueblo/Steens	19	5	9.0
Columbia Hills East 2	11	3	9.2
Goodnoe Hills	14	4	9.2
Blackfeet Area 1	460	140	9.3
Klondike	65	16	9.7
Horse Heaven	70	17	10.1
Great Falls	440	108	10.4
Livingston	218	54	10.4
Winter Ridge	91	23	10.4
Columbia Hills West	3	1	10.5
Prairie Mountain	2	1	10.9
Roosevelt	15	3	11.0
Upper Pyle Canyon	32	7	11.4
Rattlesnake Mountain 2	9	2	13.0
Total	1,501	400	

About 300 megawatts of this energy is available from the Livingston, Great Falls and Blackfeet areas in Montana. An additional 48 megawatts is available from Columbia River Gorge areas. The balance is available from scattered sites. The Montana resource is potentially much larger, but additional Montana resources are considered currently not available for development because of uncertainties regarding transmission costs and other system integration concerns.

Wind Power Planning Assumptions

For subsequent analysis of the role of wind in the resource portfolio, the wind resources considered to be available for development were aggregated into two resource blocks on the basis of energy cost. The first resource block is small: 36 megawatts of energy. That is competitive in cost with new coal projects. The second block of 364 megawatts is the balance of the 400 megawatts considered to be available for development.

Resolution of questions regarding system integration might indicate that a much larger portion of the Montana resource could be developed. A third block of additional promising Montana wind resources was defined to test the effect of a larger Montana resource potential on the resource portfolio. This block consists of 1,000 megawatts of energy from the Blackfoot Area.

Characteristics of the three blocks of wind resources are shown in Table 8-64.

Table 8-64
Wind Power Planning Assumptions

	Wind 1	Wind 2	Wind 3
Total Capacity (MW)	129	1,372	3,295
Total Average Energy (MWa)	36	364	1,000
Total Firm Energy (MWa)	36	364	1,000
Unit Capacity (typical project) (MW)	32	31	30
Seasonality	Summer peaking	Winter peaking	Winter peaking
Dispatchability	Must-run	Must-run	Must-run
Siting and Licensing Lead Time (months)	12	12	12
Probability of S&L Success (%)	90	90	90
Siting and Licensing Shelf Life (years)	5	5	5
Probability of Hold Success (%)	90	90	90
Construction Lead Time (months)[a]	24	24	24
Construction Cash Flow (%/yr.)	40/60	40/60	40/60
Siting and Licensing Cost ($/kW)	$15	$16	$16
Siting and Licensing Hold Cost ($/kW/yr.)	$4	$4	$4
Construction Cost ($/kW)	$1,022	$1,105	$1,178
Fixed O,M&R Cost ($/kW/yr.)[b]	$15	$16	$16
Variable O&M Cost (mills/kWh)	11	11.5	11.6
Earliest Service	1994	1995	1999
Peak Development Rate (projects/yr.)	2	4	12
Operating Life (years)	40	40	40
Real Escalation Rates (%/yr.)			
Capital Costs	0	0	0
O&M Costs	0	0	0

[a] From turbine order.
[b] Includes post-operational capital replacement and decommissioning costs.

Conclusions

The wind energy resources of the Pacific Northwest have the potential to produce several hundred megawatts of electric energy at costs generally competitive with electric energy from new coal plants. Wind is a renewable energy resource. The bulk of the region's wind resources are found in Montana, east of the Rocky Mountains.

The total Pacific Northwest wind resource potential is very large. It is estimated that the better resource areas could yield over 4,500 megawatts of energy from nearly 19,000 megawatts of turbine capacity. Technical, institutional and environmental constraints will present barriers to development of the full potential of some wind resource areas. Several otherwise favorable sites have severe wintertime icing and snow conditions. Coastal and Columbia River Gorge site development may have to be limited for aesthetic reasons. System interconnection constraints may limit development of the large Montana resource. The Council has considered these issues and estimates that 400 megawatts of energy could be obtained from wind resources currently capable of development. The estimated cost of energy from these sites ranges from 7.4 to 13 cents per kilowatt-hour.

Wind generation produces no atmospheric emissions, solid waste by-products or water-borne pollutants. Some potential for erosion and dust exists, particularly during construction of access roads, but this can be controlled with proper design and maintenance. The aesthetic impacts of wind farms, service roads and transmission interconnects are of greater concern. Isolated machines and small wind farms can be a curiosity, but massed arrays can seriously alter the appearance of sensitive sites. Other environmental concerns include avian mortality and noise. These can be controlled by proper site selection and design.

Because wind resources are intermittent and not predictable on an hourly or daily basis, wind-generated energy is likely to be of somewhat lesser value than energy from non-intermittent resources. Large-scale development of wind-generated energy may present system integration problems. The 1,500 megawatts of wind capacity available for the portfolio is believed to be small enough, relative to the overall size of the regional system, that integration ought not to be a problem.

Development of wind resources can be undertaken in increments of 20 to 30 megawatts, allowing supply to be well-coordinated with need. Once basic site wind data is available, lead times (36 months) are among the shortest for generating resources.

Uncertainties regarding Northwest wind resource potential require consideration of action items to improve understanding of the resource.

The following actions, further described in Volume II, Chapters 1 and 16, are intended to improve understanding of this resource. These actions are expected to lead to better planning decisions, shortened wind resource development lead times, improved wind farm design and improved turbine reliability.

- Collect long-term wind resource data.

- Monitor wind power technology and resource development.

- Assess the feasibility of developing promising Pacific Northwest wind resource areas.
- Measure quantity and quality of the better wind resource areas.
- Prepare wind resource area development plans.
- Develop a cold-climate wind turbine pilot facility.
- Develop regional wind farm demonstration projects.

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APPENDIX 8-A

REPRESENTATIVE POWER PLANTS

Table 8-A-1
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

	Simple-cycle Gas Turbine Generators 1986 Power Plan	Simple-cycle Gas Turbine Generators 1989 Supplement	Combined-cycle Gas Turbine Generators 1986 Power Plan	Combined-cycle Gas Turbine Generators 1989 Supplement
Design	Westinghouse W501D Note 1A	General Electric MS7001F Note 1B	Westinghouse PACE Note 1C	General Electric STAG 207F Note 1D
No. of Units	2	2	2	1
Unit Size (MW)	105 net	139.3 (net @ ISO[a])	286 (nominal)	419.6 (net @ ISO[a])
Site	Hermiston, OR	Hermiston, OR	Hermiston, OR	Hermiston, OR
Primary Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Heat Value (Btu/scf, HHV)	1,021	1,021	1,021	1,021
Primary Fuel Delivery	HP[b] pipeline	HP[b] pipeline	HP[b] pipeline	HP[b] pipeline
Alternate Fuel	Fuel Oil No. 2	Fuel Oil No. 2	Fuel Oil No. 2	Fuel Oil No. 2
Heat Value (Btu/lb, HHV)	19,430	19,430	19,430	19,430
Alternate Fuel Delivery	Truck, Barge or Rail	Truck, Barge or Rail	Truck, Barge or Rail	Truck, Barge or Rail
Fuel Inventory	14-day FO[c] @ 208MW	14-day FO[c] @ 279MW	14-day FO[c] @ 572MW	14-day FO[c] @ 420MW
Heat Rejection	Atmosphere	Atmosphere	Mech. Draft Towers	Mech. Draft Towers
Particulates	None required	None required	None required	None required
Sulfuric Oxide Control	Low-sulfur FO[c]	Low-sulfur FO[c]	Low-sulfur FO[c]	Low-sulfur FO[c]
Nitrogen Oxide Control	Water injection	Water injection	Water injection	Water injection
Transmission - Configuration	230kV single circuit	230kV single circuit	500kV single circuit	230kV double circuit
Transmission - Length (miles)	10	10	10	10
NET CAPACITY AND HEAT RATE				
Max. Sust. Cap. @ 35F (MW)	124/unit	152.4/unit	N/A	452.2
ISO[a] Rated Cap. (MW)	104/unit	139.3/unit	586	419.6
Minimum Sust. Capacity (MW)	5/unit	N/A	N/A	N/A
Net Heat Rate @ Max. Sus. (Btu/kWh)	10,530 Note 2A	11,130 Note 2B	N/A	7,500 Note 2B
Net Heat Rate @ Rated (Btu/kWh)	10,710 Note 2A	11,480 Note 2B	9,810 Note 2A	7,620 Note 2B
Net Heat Rate @ Min. Sus. (Btu/kWh)	62,000 Note 2A	N/A	N/A	N/A

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

	Simple-cycle Gas Turbine Generators 1986 Power Plan	Simple-cycle Gas Turbine Generators 1989 Supplement	Combined-cycle Gas Turbine Generators 1986 Power Plan	Combined-cycle Gas Turbine Generators 1989 Supplement
OPERATING AVAILABILITY				
Equivalent Annual Availability	85%	85%	83%	83%
Routine Annual Insp. and Maint.	30 days	30 days	30 days	30 days
Major Inspection and Overhaul	90 days	90 days	90 days	90 days
Freq. of Major Insp. and Overhaul	5 years	5 years	5 years	5 years
Average Maintenance Outage	42 days	42 days	42 days	42 days
Other Planned and Unplanned Outages	4%	4%	6%	6%
SEASONALITY				
Monthly Capacity Potential (percent of rated capacity, exclusive of outages):				
Jan	100.0% Note 4A	114.0% Note 4B	100.0% Note 4A	110.0% Note 4C
Feb	100.0%	112.0%	100.0%	108.0%
Mar	100.0%	109.0%	100.0%	106.0%
Apr	100.0%	106.0%	100.0%	104.0%
May	100.0%	103.0%	100.0%	101.0%
Jun	100.0%	100.0%	100.0%	99.0%
Jul	100.0%	97.0%	100.0%	97.0%
Aug	100.0%	98.0%	100.0%	97.0%
Sep	100.0%	101.0%	100.0%	100.0%
Oct	100.0%	106.0%	100.0%	104.0%
Nov	100.0%	111.0%	100.0%	107.0%
Dec	100.0%	113.0%	100.0%	109.0%

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

	Simple-cycle Gas Turbine Generators 1986 Power Plan	Simple-cycle Gas Turbine Generators 1989 Supplement	Combined-cycle Gas Turbine Generators 1986 Power Plan	Combined-cycle Gas Turbine Generators 1989 Supplement
PROJECT DEVELOPMENT - SITING AND LICENSING (January 1988 dollars)				
Siting & Licensing Lead Time (mos)	24	24	24	24
Siting & Licensing Cost ($/kW)	$4.00 Note 5A	$5.00 Note 5B	$13.00 Note 5A	$6.00 Note 5C
Siting & Licensing Shelf Life (yrs.)	5	5	5	5
Siting & Licensing Hold Cost ($/kW/yr.)	$0.50 Note 5D	$0.50 Note 5E	$0.50 Note 5D	$0.40 Note 5E
Prob. of S&L Success (%)	60.0%	60.0%	60.0%	60.0%
Prob. of S&L Hold Success (%)	N/A Note 5E	90.0%	N/A Note 5E	90.0%
PROJECT DEVELOPMENT - ENGINEERING & CONSTRUCTION (January 1988 dollars)				
Construction Lead Time (mos)	30	24 Note 6A	45	36 Note 6B
Lag Between Units (mos)	none	none	3 months	N/A
Cash Flows (%/yr.) Year 1	35.0%	48.0% Note 6C	4.0%	7.9% Note 6C
Year 2	60.0%	52.0%	32.0%	40.8%
Year 3	5.0%		43.0%	51.2%
Year 4			21.0%	
Construction Cost ($/kW) (Excl. of siting, licensing and AFUDC)	$281 Note 6D	$530 Note 6E1	$714 Note 6D	$620 Note 6E2
Fuel Inventory ($/kW)	N/A Note 6G	$14	N/A Note 6G	$9
OPERATION				
Fixed Primary Fuel ($/kW/yr.)	$2.70 Note 7A1	$0.00 Note 7A2	$2.70 Note 7A1	$0.00 Note 7A2
Fixed Alternate Fuel ($/kW/yr.)	$2.70 Note 7B1	$0.00 Note 7B2	$2.70 Note 7B1	$0.00 Note 7B2
Fixed O&M ($/kW/yr.)	$1.40 Note 7C	$2.00 Note 7D	$10.20 Note 7C	$5.40 Note 7D
Capital Replacement ($/kW/yr.)	$1.40 Note 7E	$0.00 Note 7E1	$12.60 Note 7E	$0.00 Note 7E1

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

	Simple-cycle Gas Turbine Generators 1986 Power Plan	Simple-cycle Gas Turbine Generators 1989 Supplement	Combined-cycle Gas Turbine Generators 1986 Power Plan	Combined-cycle Gas Turbine Generators 1989 Supplement
OPERATION (cont.)				
Variable Primary Fuel ($/MMBtu)	$5.10 Note 7F	$3.16 Note 7G	$5.10 Note 7F	$3.16 Note 7G
Variable Alternate Fuel ($/MMBtu)	$5.70 Note 7F	$3.66 Note 7G	$5.70 Note 7F	$3.66 Note 7G
Variable O&M (mills/kWh)	2.2 Note 7C	0.1 Note 7H	0.32 Note 7C	0.3 Note 7H
Byproduct Credit	0.0	0.0	0.0	0.0
Physical Life (yrs.)	30	30	30	30

a ISO - International Standards Organization Conditions
b HP - High Pressure
c FO - Fuel Oil

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

NOTES:

1A. Plant design based on Westinghouse W501D units used at the Fredonia Plant of Puget Sound Power and Light Company. Derivation of planning assumptions is described in Appendix 6G of Volume II of the 1986 Power Plan.

1B. Plant design based on twin General Electric MS7001F gas turbines, as described in Bonneville Power Administration/Fluor, 1988.

1C. Two combined-cycle units of 286 megawatts nominal capacity each, based on Westinghouse PACE design. Each unit consists of two single-shaft, industrial-grade, open-cycle, gas turbine generators of 105 megawatts of nominal capacity (Westinghouse W501D), two heat-recovery steam generators and one steam turbine generator of 84 megawatts of gross capacity. Steam conditions are 1,210 pounds per square inch guage pressure (psig) and 950°F.

1D. General Electric STAG 207F packaged combined-cycle units of 419.6-megawatt capacity (net at ISO[a] conditions). Enclosed gas turbo-generators. Each unit consists of two single-shaft, industrial-grade gas turbine generators of 138.8 megawatts gross capacity at ISO[a] conditions (General Electric MS7001F), one heat recovery steam generator and one steam turbine generator of 151 megawatts (gross). Steam conditions are 1,465 psig and 1,000°F (throttle) and 1,000°F reheat.

2A. 1986 heat rates are based on lower heat value of fuel.

2B. 1988 heat rates are based on higher heat value of fuel.

4A. Seasonal constraints on energy capability not considered.

4B. Seasonal constraints on capacity are significant due to ambient temperature effects on combustion turbine output. From Figure 3.1 of Bonneville Power Administration/Fluor, 1986, using mean monthly temperatures for Arlington, OR (National Oceanic and Atmospheric Administration, 82).

4C. Seasonal constraints on capacity are significant due to ambient temperature effects on combustion turbine output. From Figure 3.4 of Bonneville Power Administration/Fluor, 1986, using mean monthly temperatures for Arlington, OR (National Oceanic Atmospheric Administration, 82).

5A. 1986 estimates, escalated to January 1988 using gross national product (GNP) deflators.

5B. Siting and Licensing cost components are as follows:
- Securing option on land (8A) - 15 percent of fair market value (Battelle, 1982)
- Conceptualization, preliminary engineering, select site, secure licenses - 1 percent of total plant cost (Battelle, 1982)

5C. Siting and Licensing cost components are as follows:
- Securing option on land (20A) - 15 percent of fair market value (Battelle, 1982).
- Conceptualization, preliminary engineering, select site, secure licenses - 1.7 percent of total plant cost (Battelle, 1982).

5D. 1986 estimates, escalated to January 1988 using GNP deflators.

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

5E. Option hold cost components are as follows:
- Project management - one engineer (Coal Options Task Force, 1985).
- Siting council fees - $0.05 kilowatt-hour per year (Washington Water Power, 1984).
- Environmental base line - $0.16 kilowatt-hour per year (Washington Water Power, 1984).
- Maintenance of land option - 15 percent of fair market value per year (Battelle, 1982).
- Owner's indirect costs - 11 percent (Washington Water Power, 1984).

Rounded to nearest $0.10 kilowatt-hour per year.

6A. Construction schedule is from Bonneville Power Administration/Fluor, 1986, Figure 5.1, rounded to the nearest year. (It is assumed that the second unit could be installed in parallel with the first unit.)

6B. Construction schedule is from Bonneville Power Administration/Fluor, 1988, Figure 5.3, rounded to the nearest year. (It is assumed that gas turbines can be installed in parallel with HSRG and steam T/G.)

6C. Annual cash flows are derived from Table 5-4 of Bonneville Power Administration/Fluor, 1988, adjusted to nearest year.

6D. 1986 estimates, escalated by appropriate indices from Handy-Whitman, 1988.

6E1. Construction cost components are as follows:
- Land purchase - 20 Acres @ $2,000 per acre (1986 dollars).
- Direct construction costs (Including Plant Facilities Investment, Bonneville Power Administration/Fluor, 1988, T.5-2 ($115.7MM) and fuel oil storage (Scaled from Kaiser, 1985, $5.0MM).
- Contingency - 10 percent of direct and indirect costs (Bonneville Power Administration/Fluor, 1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, including contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Transmission interconnect - Bonneville estimates.
- Spare parts inventory - Bonneville Power Administration/Fluor, 1986, Table 6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Natural gas pipeline - two miles at $500,000 per mile (Bonneville).
- Start-up costs as noted in note 6F.

All costs escalated to January 1988 using Handy-Whitman, 1988, where appropriate, GNP deflator otherwise. Rounded to the nearest $10 per kilowatt.

6E2. Construction cost components are as follows:
- Land purchase - 20 acres @ $2,000 per acre (1986 dollars).
- Direct construction costs (including total plant investment from Bonneville Power Administration/Fluor, 1988, T.5-3 ($208.7 million) and fuel oil storage (Scaled from Kaiser, 1985, $5.0 million).
- Contingency - 10 percent of direct and indirect costs (Bonneville Power Administration/Fluor, 1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, including contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Transmission interconnect - Bonneville estimates.
- Spare parts inventory - Bonneville Power Administration/Fluor, 1986, Table 6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Natural gas pipeline - two miles at $500,000 per mile (Bonneville).
- Start-up costs as noted in note 6F.

All costs escalated to January 1988 using Handy-Whitman, 1988, where appropriate, GNP deflator otherwise. Rounded to the nearest $10 per kilowatt.

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

6F. Start-up cost components are as follows:
- One month of fixed operating and maintenance costs.
- One month of variable operating and maintenance costs.
- One week at full capacity primary fuel cost.
- Two percent of total construction cost.

6G. Fuel inventory costs and start-up costs were not broken out of the 1986 estimates.

7A1. 1986 estimate escalated to January 1988 using GNP deflator.

7A2. The 1986 fixed primary-fuel cost was the cost of the gas pipeline to the plant. The capital cost of this pipeline is now included in plant capital costs.

7B1. 1986 estimate escalated to January 1988 using GNP deflator.

7B2. The 1986 fixed secondary-fuel cost was the cost of an oil pipeline to the plant. The current representative plant would use rail, truck or barge delivery of fuel oil.

7C. 1986 estimate escalated to January 1988 using Bonneville Power Administration "JEFOM" steam plant operating and maintenance deflator.

7D. Fixed operating and maintenance costs include:
- Standby maintenance material costs - Bonneville Power Administration/Flour, 1988, T.6-3.
- Operating, maintenance and support labor (Bonneville Power Administration/Fluor, 1988, T.6-4).
- General and administrative costs (17 percent, Pacific Northwest Laboratories, 1985,)

Rounded to nearest $0.10 kilowatt-hour per year.

7E. 1986 estimate escalated to January 1988 using Handy-Whitman, 1988, gas turbogenerator index.

7E1. Interim capital replacement is included in operating and maintenance estimates.

7F. 1986 base year fuel prices, unescalated.

7G. 1989 supplement, Chapter 4, section on utility fuel prices.

7H. Variable operating and maintenance costs include the following:
- "Fixed" maintenance materials (Bonneville Power Administration/Fluor T.6-4) less standby maintenance materials (Bonneville Power Administration/Fluor T.6-3).
- Consumables (Bonneville Power Administration/Fluor, 1988, T.6-6).
- General and administrative costs of 17 percent (Pacific Northwest Laboratories, 1985,).

Rounded to nearest 0.1 mills per kilowatt-hour.

Table 8-A-1 (cont.)
Simple-cycle and Combined-cycle Combustion Turbine Power Plants

REFERENCES:

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WWP, 1984: Washington Water Power Company. Creston Generating Station Status Report, July 1984.

Table 8-A-2
Pulverized-Coal-Fired Power Plants

	Two 270-Megawatt Units 1986 Power Plan	Two 270-Megawatt Units 1989 Supplement	Two 650-Megawatt Units 1986 Power Plan	Two 650-Megawatt Units 1989 Supplement
Design	Pulverized firing 2,400 psig steam 1,000°F/1,000°F reheat 3.5Hga back pressure Note 1A	Pulverized firing 2,400 psig steam 1,000°F/1,000°F reheat 2.95Hga back pressure Notes 1B and 1F	Pulverized firing 2,400 psig steam 1,000°F/1,000°F reheat 3.5Hga back pressure Note 1C	Pulverized firing 2,400 psig steam 1,000°F/1,000°F reheat 2.95Hga back pressure Notes 1D and 1F
Number of Units	2	2	2	2
Unit Size (MW)	270 (gr)/250 (net)	270 (gr)/250 (net)	650 (gr)/603 (net)	650 (gr)/603 (net)
Site	Hermiston, OR	Hermiston, OR	Hermiston, OR	Hermiston, OR
Primary Fuel	WY subbituminous	WY subbituminous	WY subbituminous	WY subbituminous
Heat Value (Btu/pound)	8,445	8,445	8,445	8,445
Fuel Delivery	Unit train	Unit train	Unit train	Unit train
Fuel Inventory	90 day @ 500MW	90 day @ 500MW	90 day @ 500MW	90 day @ 500MW
Heat Rejection	Mech. draft towers	Mech. draft towers	Mech. draft towers	Mech. draft towers
Flash Control	Precipitators	Precipitators	Precipitators	Precipitators
Sulfuric Oxide Control	Wet scrubbers	Wet scrubbers	Wet scrubbers	Wet scrubbers
Nitrogen Oxide Control	Comb. control	Comb. control	Comb. control	Comb. control
Transmission - Configuration	500kV single circuit	230kV dbl cir. Note 1G1	500kV double circuit	500kV double circuit Note 1G2
Transmission - Length (miles)	10	10	10	10
CAPACITY AND HEAT RATES				
Max. Sust. Cap. (MW/unit)	262	262	633	633
Rated Capacity (MW/unit)	250	250	603	603
Minimum Sustainable Cap. (MW/unit)	63	63	151	151
Net Heat Rate @ Max. Sus. (Btu/kWh)	10,320	11,145 Note 2A	10,210	10,970 Note 2A
Net Heat Rate @ Rated (Btu/kWh)	10,190	11,005	10,080	10,856
Net Heat Rate at Min. Sus. (Btu/kWh)	11,670	N/A	11,940	N/A

Table 8-A-2 (cont.)
Pulverized-Coal-Fired Power Plants

	Two 270-Megawatt Units 1986 Power Plan	Two 270-Megawatt Units 1989 Supplement	Two 650-Megawatt Units 1986 Power Plan	Two 650-Megawatt Units 1989 Supplement
OPERATING AVAILABILITY				
Equivalent Annual Availability	77.0%	77.0%	75.0%	75.0%
Routine Annual Insp. & Maint.	30 days	30 days	30 days	30 days
Major Inspection & Overhaul	60 days	60 days	60 days	60 days
Freq. of Major Insp. & Overhaul	5 years	5 years	5 years	5 years
Average Maintenance Outage	36 days	36 days	36 days	36 days
Other Planned & Unplanned Outages	17%	17%	15%	15%
ENERGY PRODUCTION PROFILE				
Monthly Capacity Potential (percent of rated capacity, exclusive of outages):				
Jan	100.0% Note 4A	100.0%	100.0% Note 4A	100.0%
Feb	100.0%	100.0%	100.0%	100.0%
Mar	100.0%	100.0%	100.0%	100.0%
Apr	100.0%	100.0%	100.0%	100.0%
May	100.0%	100.0%	100.0%	100.0%
Jun	100.0%	100.0%	100.0%	100.0%
Jul	100.0%	100.0%	100.0%	100.0%
Aug	100.0%	100.0%	100.0%	100.0%
Sep	100.0%	100.0%	100.0%	100.0%
Oct	100.0%	100.0%	100.0%	100.0%
Nov	100.0%	100.0%	100.0%	100.0%
Dec	100.0%	100.0%	100.0%	100.0%

Table 8-A-2 (cont.)
Pulverized-Coal-Fired Power Plants

	Two 270-Megawatt Units 1986 Power Plan	Two 270-Megawatt Units 1989 Supplement	Two 650-Megawatt Units 1986 Power Plan	Two 650-Megawatt Units 1989 Supplement
PROJECT DEVELOPMENT - SITING AND LICENSING (January 1988 dollars)				
Siting & Licensing Lead Time (mos)	48	48	48	48
Siting & Licensing Cost ($/kW)	$57	$32 Note 5A	$40	$23 Note 5A
Siting & Licensing Shelf Life (yrs.)	5	5	5	5
Siting & Licensing Hold Cost ($/kW/yr.)	$0.60	$0.90 Note 5B	$0.30	$0.80 Note 5B
Prob. of S&L Success (%)	70.0%	70.0%	70.0%	70.0%
Prob. of S&L Hold Success (%)	N/Est.	90.0%	N/Est.	90.0%
PROJECT DEVELOPMENT - ENGINEERING & CONSTRUCTION (January 1988 dollars)				
Const. Lead Time (to first unit) (mos)	60	60	72	72
Lag Between Units (mos)	12	12	12	12
Cash Flows (%/yr.): Year 1	2.0%	2.0%	4.0%	4.0% Note 6A
Year 2	8.0%	8.0%	11.0%	11.0%
Year 3	24.0%	24.0%	17.0%	17.0%
Year 4	40.0%	40.0%	27.0%	27.0%
Year 5	23.0%	23.0%	28.0%	28.0%
Year 6	3.0%	3.0%	12.0%	12.0%
Year 7			1.0%	1.0%
Construction Cost ($/kW) (Excl. of siting, licensing & AFUDC)	$1,749	$1,670 Notes 6B & 6E	$1,227	$1,210 Notes 6C & 6E
Fuel Inventory ($/kW)	$44	$35	$44	$35
OPERATION (January 1988 dollars)				
Fixed Primary Fuel ($/kW/yr.)	$0.00	$8.60 Note 7A	$0.00	$8.60 Note 7A
Fixed Alternate Fuel ($/kW/yr.)	N/A	N/A	N/A	N/A
Fixed O&M ($/kW/yr.)	$20.10	$32.80 Note 7B	$10.10	$20.50 Note 7B
Capital Replacement ($/kW/yr.)	$12.60	Inc. in FXOM	$12.60	Inc. in FXOM

Table 8-A-2 (cont.)
Pulverized-Coal-Fired Power Plants

	Two 270-Megawatt Units		Two 650-Megawatt Units	
	1986 Power Plan	1989 Supplement	1986 Power Plan	1989 Supplement
OPERATION (January 1988 dollars) (cont.)				
Variable Primary Fuel ($/MMBtu)	$2.00	$1.49	$2.00	$1.49
Variable Alternate Fuel ($/MMBtu)	N/A	N/A	N/A	N/A
Variable O&M (mills/kWh)	2.1	2.3 Note 7D	1.2	1.4 Note 7D
Consumables (mills/kWh)	Inc. in VROM	0.7 Note 7E	Inc. in VROM	0.5 Note 7E
Physical Life (years)	40	same	40	same

Table 8-A-2 (cont.)
Pulverized-Coal-Fired Power Plants

NOTES:

1A. Details regarding planning assumptions are provided in Volume II, Appendix 6C of the 1986 Power Plan.

1B. Plant design based on Case Study 2 (two 270-megawatt [gross] coal-fired units) appearing in Kaiser(87).

1C. Details regarding planning assumptions are provided in Volume II, Appendix 6C of the 1986 Power Plan.

1D. Plant design based on Case Study 1 (two 650-megawatt [gross] coal-fired units) appearing in Kaiser(87).

1F. 1986 turbine back pressure was incorrect.

1G1. Transmission voltage changed to 230kV to agree with case study switchyard assumptions.

1G2. Kaiser estimates used a 230kV switchyard. 1988 update estimates were adjusted to represent a 500kV switchyard.

2A. 1986 heat rates were gross; 1989 proposal corrects to net.

4A. Seasonal constraints on energy capability judged insignificant.

5A. 1986 assumes purchase of site; 1989 assumes optioning of land. Estimated cost of miscellaneous easements and rights of way, owner's preconstruction administrative costs, permits and licenses, geotechnical investigation and environmental impact statement from Kaiser(86).

5B. Annual land option fee (15 percent of market value) added to 1986 estimate; rounded to nearest $0.10.

6A. Cashflow adjusted to correspond with Kaiser(87).

6B. Construction cost based on Kaiser(87), escalated to 1988 dollars and adjusted to include transmission link and owner's costs during construction; and to exclude fuel inventory costs (land costs retained i.a.w. Note 5A); rounded to the nearest $10 per kilowatt.

6C. Construction cost based on Kaiser(87), escalated to 1988 dollars and adjusted to include 500kV switchyard, transmission link and owner's costs during construction; and to exclude 230kV swithyard and fuel inventory costs (land costs retained i.a.w. Note 5A); rounded to the nearest $10 per kilowatt.

6E. Start-up (pre-production) costs calculated i.a.w. Electric Power Research Institute, 1986.

7A. Annual fixed costs of purchase and maintenance of unit train rolling stock.

7B. Annual fixed operating and maintenance costs calculated as 70 percent of the total of annual labor costs (from Kaiser, 1987), and 1.8 percent of total construction cost (excluding start-up costs); rounded to the nearest $0.10 kilowatt-hour per year.

7D. Variable operating and maintenance costs calculated as 30 percent of the total of annual labor costs (from Kaiser, 1987), and 1.8 percent of total capital costs (excluding fuel inventory, working capital and start-up costs), 70-percent capacity factor used; rounded to the nearest 0.1 mill per kilowatt-hour.

7E. Consumables include costs of materials, chemicals, utilities, and sludge and ash disposal (from Kaiser, 1987); rounded to the nearest 0.1 mill per kilowatt-hour.

Table 8-A-2 (cont.)
Pulverized-Coal-Fired Power Plants

REFERENCES:

EPRI(86): Electric Power Research Institute. Technical Assessment Guide (EPRI P-4463-SR) Volume I, December 1986.

Kaiser(86): Kaiser Engineers. Preconstruction Costs and Schedules for Comparative Generation Study Coal-fired Powerplants. Prepared for Bonneville Power Administration. November 1986.

Kaiser(87): Kaiser Engineers. Comparative Generation Study Coal-fired Powerplants. Prepared for Bonneville Power Administration. October 1987.

Table 8-A-3
Atmospheric Fluidized-Bed Combustion Coal-Fired Power Plants

	Single Small Unit 1986 Power Plan	Single Small Unit 1989 Supplement	Two Large Units 1986 Power Plan	Two Large Units 1989 Supplement
Design	Atm. fluidized-bed 1,500 psig steam 1,000°F, no reheat 2.0Hga back pressure Note 1A1	Overbed feed AFBC 2,400 psig steam 1,000/1,000°F reheat Note 1A2	No equivalent	Underbed feed AFBC 2,400 psig steam 1,000/1,000°F reheat Note 1A3
Number of Units	1	1		2
Unit Size (MW)	113 (gr)/110 (net)	210 (gr)/197 (net)		544 (gr)/509 (net)
Site	Hermiston, OR	Hermiston, OR		Hermiston, OR
Primary Fuel	WY Subbituminous	WY Subbituminous		WY Subbituminous
Heat Value (Btu/pound)	8,445	8,445		8,445
Fuel Delivery	Unit train	Same		Unit train
Fuel Inventory	90 day @ 110MW	90 day @ 197MW		90 day @ 1,018MW
Heat Rejection	Mech. draft towers	Mech. draft towers		Mech. draft towers
Flash Control	Cyclones and baghouse	Baghouse		Baghouse
Sulfuric Oxide Control	Limestone injection	Limestone injection		Limestone injection
Nitrogen Oxide Control	Comb. temp control	Comb. temp control		Comb. temp control
Transmission Interconnect	Not specified	10mi 230kV dbl ckt		10mi 500kV dbl ckt
CAPACITY AND HEAT RATES				
Max. Sust. Cap. (MW/unit)	N/A	N/A		N/A
Rated Capacity (MW/unit)	110	197		509
Minimum Sust. Cap. (MW/unit)	39	N/A		N/A
Net Heat Rate @ Max. Sus. (Btu/kWh)	N/A	N/A		N/A
Net Heat Rate @ Rated (Btu/kWh)	11,200	9,885 Note 2A		9,851
Net Heat Rate at Min. Sus. (Btu/kWh)	N/A	N/A		N/A

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-Fired Power Plants

	Single Small Unit		Two Large Units	
	1986 Power Plan	1989 Supplement	1986 Power Plan	1989 Supplement
OPERATING AVAILABILITY				
Equivalent Annual Availability	75%	81% Note 3A		74% Note 3B
Routine Annual Insp. & Maint.	35 days	N/A		N/A
Major Inspection & Overhaul	N/A	N/A		N/A
Freq. of Major Insp. & Overhaul	N/A	N/A		N/A
Average Maintenance Outage	35 days	34 days Note 3C		42 days Note 3D
Other Planned & Unplanned Outages	17%	10% Note 3A		16% Note 3B
ENERGY PRODUCTION PROFILE				
Monthly Energy Production Potential, (Percent of average annual potential, exclusive of outages):				
Jan	100.0% Note 4A	100.0% Note 4A		100.0%
Feb	100.0%	100.0%		100.0%
Mar	100.0%	100.0%		100.0%
Apr	100.0%	100.0%		100.0%
May	100.0%	100.0%		100.0%
Jun	100.0%	100.0%		100.0%
Jul	100.0%	100.0%		100.0%
Aug	100.0%	100.0%		100.0%
Sep	100.0%	100.0%		100.0%
Oct	100.0%	100.0%		100.0%
Nov	100.0%	100.0%		100.0%
Dec	100.0%	100.0%		100.0%

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-Fired Power Plants

	Single Small Unit 1986 Power Plan	Single Small Unit 1989 Supplement	Two Large Units 1986 Power Plan	Two Large Units 1989 Supplement
PROJECT DEVELOPMENT - SITING AND LICENSING (January 1988 dollars)				
Siting & Licensing Lead Time (mos)	48	48		48
Siting & Licensing Cost ($/kW)	$43 Note 5A	$41 Note 5B		$23 Note 5C
Siting & Licensing Shelf Life (yrs.)	5	5		5
Siting & Licensing Hold Cost ($/kW/yr.)	$1.00 Note 5A	$1.40 Note 5D		$0.50 Note 5D
Prob. of S&L Success (%)	70.0%	70.0%		70.0%
Prob. of S&L Hold Success (%)	N/Est.	90.0%		90.0%
PROJECT DEVELOPMENT - ENGINEERING & CONSTRUCTION (January 1988 dollars)				
Const. Lead Time (to first unit) (mos)	72	64 Note 6A		76 Note 6B
Lag Between Units (mos)	N/A	N/A		12 Note 6C
Cash Flows (%/yr.): Year 1	1.0%	4.0% Note 6D		4.0% Note 6E
Year 2	7.0%	11.0%		11.0%
Year 3	18.0%	39.0%		17.0%
Year 4	47.0%	45.0%		27.0%
Year 5	22.0%	5.0%		28.0%
Year 6	5.0%			12.0%
Year 7				10.0%
Construction cost ($/kW) (Excl. of siting, licensing & AFUDC)	$1,823 Note 6F	$1,760 Note 6G		$1,270 Note 6G
Fuel Inventory ($/kW)	$48 Note 6H1	$0 Note 6H2		$0 Note 6H2
OPERATION (January 1988 dollars)				
Fixed Primary Fuel ($/kW/yr.)	$0.00	$8.60 Note 7A		$8.60 Note 7A
Fixed Alternate Fuel ($/kW/yr.)	N/A	N/A		N/A
Fixed O&M ($/kW/yr.)	$36.20 Note 7B	$37.10 Note 7C		$20.70 Note 7C
Capital Replacement ($/kW/yr.)	$12.60	Inc. in FXOM		Inc. in FXOM

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-Fired Power Plants

	Single Small Unit 1986 Power Plan	Single Small Unit 1989 Supplement	Two Large Units 1986 Power Plan	Two Large Units 1989 Supplement
		OPERATION (January 1988 dollars)		
Variable Primary Fuel ($/MMBtu)	$2.00 Note 7A	$1.49 Note 7A		$1.49 Note 7A
Variable Alternate Fuel ($/MMBtu)	N/A	N/A		N/A
Variable O&M (mills/kWh)	1.1 Note 7B	4.8 Note 7D		3.1 Note 7D
Consumables (mills/kWh)	Inc. in VROM	Inc. in VROM		Inc. in VROM
Physical Life (years)	40	30		30

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-fired Power Plants

NOTES:

1A1. Plant design based on 1x110-megawatts (net) AFBC coal-fired power plant case appearing in Bonneville Power Administration/Kaiser, 1985. Derivation of planning assumptions is described in Volume II, Appendix 6D of the 1986 Power Plan.

1A2. Plant design based on 1x200-megawatt overbed-fired AFBC coal-fired power plant case, Hermiston, Oregon, location, appearing in Electric Power Research Institute, 1987.

1A3. Plant design based on 2x500-megawatt overbed-fired AFBC plant, Hermiston, Oregon, location, appearing in Electric Power Research Institute, 1987.

2A. Heat rate is from McGowin, 1988.

3A. From Electric Power Research Institute, 1986 Exhibit B.5-10B, Technology 10.2.

3B. From Electric Power Research Institute, 1986 Exhibit B.5-10B, Technology 10.1.

3C. Planned outages are from Electric Power Research Institute, 1986 Exhibit B.5-10B, Technology 10.2, converted to days.

3D. Planned outages are from Electric Power Research Institute, 1986 Exhibit B.5-10B, Technology 10.1, converted to days.

4A. Seasonal constraints on energy capability judged insignificant.

5A. 1986 estimates, escalated to January 1988 using GNP deflators.

5B. Siting and licensing cost components are as follows:
- Securing option on land (500 acres @ 15 percent of market value [$2,000 per acre], Battelle, 1982).
- Conceptualization, preliminary engineering site selection, secure licenses - 3 percent of total plant cost (from Bonneville Power Administration/Kaiser, 1986, rounded to nearest percentage).

5C. Siting and licensing cost components are as follows:
- Securing option on land (750 acres @ 15 percent of market value [$2,000 per acre], Battelle, 1982).
- Conceptualization, preliminary engineering site selection, secure licenses - 3 percent of total plant cost (from Bonneville Power Administration/Kaiser, 1986, rounded to nearest percentage).

5D. Option hold cost components are as follows:
- Project management - 1 engineer (Coal Options Task Force, 1985).
- Siting council fees - $0.05 kilowatts per year (WWP, 1984).
- Environmental base line - $0.16 kilowatts per year (WWP, 1984).
- Maintenance of land option - 15 percent of fair market value per year (Battelle, 1982).
- Owner's indirect costs - 11 percent (WWP, 1984).

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-fired Power Plants

6A. Construction lead times are from Electric Power Research Institute, 1987, Figure 4-13, plus 24 months for detailed engineering.

6B. Construction lead times are from Electric Power Research Institute, 1987, Figure 4-14, plus 24 months for detailed engineering.

6C. Unit 2 lag is from Electric Power Research Institute, 1987, Figure 4-14.

6D. From Kaiser, 1987, one 270-megawatt pulverized-coal unit.

6E. From Kaiser, 1987, two 650-megawatt pulverized-coal units (cash flows for years one and two combined).

6F. 1986 estimates, escalated to January 1988, using Handy-Whitman indices.

6G. Overnight construction costs include the following:
- Land
- Direct plant construction costs
- Contractor overhead and profit
- Engineering
- Construction management
- Contingency
- Owner's costs during construction
- Transmission interconnect
- Spare parts
- Prepaid royalties
- Socioeconomic impact mitigation
- Start-up costs

Construction costs are derived from McGowin, 1988, adjusted as follows:
- Land cost component adjusted to $2,000 per acre from $6,500 per acre (page C-32 of Electric Power Research Institute, 1987).
- Cost of transmission interconnect added (Bonneville estimates).
- Owner's costs during construction added (4 percent of direct and indirect costs).
- Start-up (pre-production) costs excluded.
- Socioeconomic impact mitigation costs added (1 percent of total direct and indirect plant costs, Coal Options Task Force, 1985).
- Costs escalated from January 1983 to January 1988, using Handy-Whitman indices.

Start-up cost components are as follows:
- One month of fixed operating and maintenance costs.
- One month of variable operating and maintenance costs.
- One week at rated capacity primary-fuel cost.
- Two percent of total construction cost.
- 1986 fuel costs currently used.

6H1. 1986 estimates, escalated to January 1988, using GNP deflators.

6H2. Fuel inventory cost is based on 90 days operation at rated capacity.

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-fired Power Plants

7A. Annual capital and maintenance cost of railroad rolling stock.

7B. 1986 estimate escalated to January 1988, using Bonneville "JEFOM" escalation series.

7C. Fixed operating and maintenance cost components are as follows:
- Operating labor.
- Maintenance costs.
- Overhead charges.

Fixed operating and maintenance costs are derived from McGowin, 1988, escalated to January 1988, using the Bonneville "JEFOM" steam plant operating and maintenance deflator.

7D. Variable operating and maintenance costs components are as follows:
- Utilities.
- Raw materials and chemicals (Consumables).

Variable operating and maintenance costs are derived from McGowin, 1988, escalated to January 1988, using the Bonneville "JEFOM" steam plant operating and maintenance deflator.

Table 8-A-3 (cont.)
Atmospheric Fluidized-Bed Combustion Coal-fired Power Plants

REFERENCES:

Battelle, 1982: Battelle, Pacific Northwest Laboratories. Development and Characterization of Electric Power Conservation and Supply Resource Planning Options. August 1982.

Bonneville Power Administration/Kaiser, 1985: Kaiser Engineers Power Corporation. Bonneville Power Administration Comparative Electric Generation Study (Supplemental Studies). February 1985.

Bonneville Power Administration/Kaiser, 1986: Kaiser Engineers. Preconstruction Costs and Schedules for Comparative Electric Generation Study Coal-Fired Power Plants. November 1986.

Bonneville Power Administration/Kaiser, 1987: Kaiser Engineers. Comparative Electric Generation Study, Coal-fired Power Plants. October 1987.

Coal Options Task Force, 1985: Northwest Power Planning Council Coal Options Task Force, convened for preparation of the 1986 Power Plan.

EPRI, 1986: Electric Power Research Institute. TAG - Technical Assessment Guide (EPRI P-4463-SR).

EPRI, 1987: Electric Power Research Institute. Evaluation of Alternative Steam Generator Designs for Atmospheric Fluidized-bed Combustion Plants (EPRI CS-5296). July 1987.

Handy-Whitman, 1988: Whitman, Requardt and Associates. Handy-Whitman Index of Public Utility Construction Costs, Preliminary Numbers, Bulletin 127. January 1988.

McGowin, 1988: Letter from C.R. McGowin (EPRI) to Kevin Watkins (Bonneville Power Administration) of March 23, 1988, regarding cost breakouts and additional background information on EPRI CS-5296 Hermiston, Oregon, cases.

PNUCC, 1984: Pacific Northwest Utilities Conference Committee. Working Paper Development of Generic Resource Data. October 1984.

WWP, 1984: Washington Water Power Company. Creston Generating Station Status Report. July 1984.

Table 8-A-4
Coal-Gasification Combined-Cycle Power Plant

	Simple-Cycle Combustion Turbines (Total Plant)	Combined-Cycle Combustion Turbines (Incremental/Plant)	Coal Gasification Combined-Cycle (Incremental/Plant)
Design	GE MS7001F Enclosed	GE STAG 207F Enclosed CTs Note 1A1	Shell gasifier w/GE STAG 207F Note 1A2
Configuration: CT Section	2 x 139MW (ISO)	2 x 139MW (ISO)	2 x 139MW (ISO)
HRSG/TG Section	N/A	1 x 142MW (ISO)	1 x 141MW (ISO)
Site	Hermiston, OR	Hermiston, OR	Hermiston, OR
Primary Fuel	Natural Gas	Natural Gas	Wyoming sub. PRB coal
Heat Value	1,021 Btu/scf (HHV)	1,021 Btu/scf (HHV)	8,445 Btu/lb
Primary Fuel Delivery	High Pressure Pipeline	High Pressure Pipeline	Unit Train
Alternate Fuel	Fuel Oil No. 2	Fuel Oil No. 2	Natural Gas
Heat Value	19,430 Btu/lb (HHV)	19,430 Btu/lb (HHV)	1,021 Btu/scf (HHV)
Alternate Fuel Delivery	Truck, Barge or Rail	Truck, Barge or Rail	High Pressure Pipeline
Fuel Inventory	14 day FO @ 270MW	14 day FO @ 410MW	90 days coal @ 419MW
Heat Rejection	Atmosphere	Mech. Draft Towers	Mech. Draft Towers
Particulates	None required	None required	Pre-comb. gas treatment
Sulfuric Oxide Control	Low-sulfur fuel oil	Low-sulfur fuel oil	"Selexol" acid gas removal
Nitrogen Oxide Control	Water injection	Water injection	Vapor injection
Transmission Interconnect	10 mi 230kV single circuit	10 mi 230kV double circuit	10 mi 230kV double circuit
CAPACITY AND HEAT RATES			
Max. Sust. Cap. @ 35F (MW)	152.4/unit Note 2A	452.2 Note 2A	451 Note 2B
Rated Capacity @ ISO (MW)	139.3/unit Note 2A	419.6 Note 2A	419 Note 2B
Minimum Sustainable Cap. (MW)	N/A	N/A	N/A
Net Heat Rate @ Max. Sus. (Btu/kWh)	11,130 Note 2A	7,500 Note 2A	9,160 Note 2B
Net Heat Rate @ Rated (Btu/kWh)	11,480 Note 2A	7,620 Note 2A	9,270 Note 2B
Net Heat Rate at Min. Sus. (Btu/kWh)	N/A	N/A	N/A

Table 8-A-4 (cont.)
Coal-Gasification Combined-Cycle Power Plant

	Simple-Cycle Combustion Turbines (Total Plant)		Combined-Cycle Combustion Turbines (Incremental/Plant)		Coal Gasification Combined-Cycle (Incremental/Plant)	
OPERATING AVAILABILITY						
Equivalent Annual Availability	85.0%		83.0%		80%	
Routine Annual Insp. & Maint.	30 days		30 days		30 days	
Major Inspection & Overhaul	90 days		90 days		90 days	
Freq. of Major Insp. & Overhaul	5 years		5 years		5 years	
Average Maintenance Outage	42 days		42 days		42 days	
Other Planned & Unplanned Outages	4.0%		6.0%		9%	
SEASONALITY						
Monthly Energy Production Potential (Percent of average annual, exclusive of outages):						
Jan	114.0%	Note 4A1	110.0%	Note 4A2	108.2%	Note 4A3
Feb	112.0%		108.0%		106.0%	
Mar	109.0%		106.0%		104.3%	
Apr	106.0%		104.0%		102.0%	
May	103.0%		101.0%		99.2%	
Jun	100.0%		99.0%		96.8%	
Jul	97.0%		97.0%		94.5%	
Aug	98.0%		97.0%		95.0%	
Sep	101.0%		100.0%		97.7%	
Oct	106.0%		104.0%		101.6%	
Nov	111.0%		107.0%		105.5%	
Dec	113.0%		109.0%		107.2%	

Table 8-A-4 (cont.)
Coal-Gasification Combined-Cycle Power Plant

	Simple-Cycle Combustion Turbines (Total Plant)	Combined-Cycle Combustion Turbines (Incremental/Plant)	Coal Gasification Combined-Cycle (Incremental/Plant)
PROJECT DEVELOPMENT - SITING AND LICENSING (January 1988 dollars)			
Siting & Licensing Lead Time (mos)	48 Note 5A1	12/48 Note 5A2	12/48 Note 5A3
Siting & Licensing Cost ($/kW)	$49 Note 5B1	$8/33 Note 5B2	$16/$38 Note 5B3
Siting & Licensing Shelf Life (yrs.)	5	5	5
Siting & Licensing Hold Cost ($/kW/yr.)	$0.60 Note 5D1	unknown/$0.50	unknown/$0.50
Prob. of S&L Success (%)	75.0%	90%/75%	75.0%
Prob. of S&L Hold Success (%)	90.0%	90.0%	90.0%
PROJECT DEVELOPMENT - ENGINEERING & CONSTRUCTION (January 1988 dollars)			
Const. Lead Time (to first unit) (mos)	24	38/38	39/39
Lag Between Units (mos)	none	none	none
Cash Flows (%/yr.): Year 1	48.0%	8.0%	12.0%
Year 2	52.0%	41.0%	48.0%
Year 3		51.0%	40.0%
Construction Cost ($/kW) (Excl. of siting, licensing and AFUDC)	$530 Note 6D1	$280/620 Note 6D2	$1,230/1820 Note 6D3
Fuel Inventory ($/kW)	$14	$3/9	$30/30
OPERATION (January 1988 dollars)			
Fixed Primary Fuel ($/kW/yr.)	$0.00	$0.00	$8.60 Note 7A3
Fixed Alternate Fuel ($/kW/yr.)	$0.00	$0.00	$0.00
Fixed O&M ($/kW/yr.)	$2.00 Note 7C1	$5.40 Note 7C2	$61.22 Note 7C3
Capital Replacement ($/kW/yr.)	Inc. in FXOM	Inc. in FXOM	Inc. in FXOM

Table 8-A-4 (cont.)
Coal-Gasification Combined-Cycle Power Plant

	Simple-Cycle Combustion Turbines (Total Plant)	Combined-Cycle Combustion Turbines (Incremental/Plant)	Coal Gasification Combined-Cycle (Incremental/Plant)
	OPERATION (January 1988 dollars)		
Variable Primary Fuel ($/MMBtu)	$3.16	$3.16	$1.49
Variable Alternate Fuel ($/MMBtu)	$3.66	$3.66	$3.16
Variable O&M (mills/kWh)	0.1 Note 7G1	0.2 Note 7G2	0.2 Note 7G3
Consumables (mills/kWh)	0.0 Note 7G1	0.1 Note 7G2	0.8 Note 7H3
Byproduct Credit (mills/kWh)	none	none	0.2 Note 7I3
Physical Life (years)	30	30	30

Table 8-A-4 (cont.)
Coal-Gasification Combined-Cycle Power Plant

NOTES:

1A1. One General Electric 207F STAG combined-cycle plant. This plant consists of two single-shaft, heavy-duty, combustion turbines, (General Electric MS7001S), one heat-recovery steam generator and one steam turbine generator. Steam conditions are 905 psig 998°F/1,000°F reheat. Plant design based on case study Phase 3 appearing in Bonneville Power Administration, 1986.

1A2. Shell entrained gasifier supplying medium-Btu gas to one General Electric 207F STAG combined-cycle plant (see Note 1B). Plant design based on case study Phase 4 appearing in Bonneville Power Administration, 1986.

2A. From Table 3-2, Bonneville Power Administration, 1988 (more recent data regarding the MS7001F than Bonneville Power Administration, 1986).

2B. From Table 2-3, Bonneville Power Administration, 1986.

4A1. Seasonal effects on capacity are significant due to ambient temperature effects on combustion turbine output. From Figure 3.1 of Bonneville Power Administration, 1986, using mean monthly temperatures for Arlington, Oregon (NOAA, 82).

4A2. Seasonal effects on capacity are significant due to ambient temperature effects on combustin turbine output. From Figure 3.4 of Bonneville Power Administration, 1986, using mean monthly temperatures for Arlington, Oregon (NOAA, 82).

4A3. Seasonal effects on capacity are significant due to ambient temperature effects on combustion turbine output. From least squares regression on power versus ambient temperature data of Table 2-3 of Bonneville Power Administration, 1986, using mean monthly temperatures for Arlington, Oregon (NOAA, 82).

5A1. The siting and licensing lead time for a "gasifier-ready" combustion turbine plant is assumed to be the same as for a pulverized-coal-fired power plant.

5A2. A permit review lead time of 12 months is assumed to be required for conversion of "gasifier-ready" combustion turbines to combined cycle. The siting and licensing lead time for a complete "gasifier-ready" combined-cycle plant is assumed to be the same as for a pulverized-coal-fired power plant.

5A3. A permit review lead time of 12 months is assumed to be required for addition of a coal gasification plant to the "gasifier-ready" combined-cycle plant. The siting and licensing lead time for a complete gasification plant is assumed to be the same as for a pulverized-coal-fired power plant.

5B1. Siting and licensing costs include:
- Securing option on land at 15 percent fair market value - Battelle (1982).
- Easements and rights of way, owner's costs, permits & licenses, geotechnical studies and environmental impact statement - Bonneville Power Administration (1986) T.1-1.

5B2. Siting and licensing costs for complete plant include:
- Securing option on land at 15 percent fair market value - Battelle (1982).
- Easements and rights of way, owner's costs, permits and licenses, geotechnical studies and environmental impact statement - Bonneville Power Administration (1986) T.1-1.

Siting and licensing costs for combined-cycle increment include estimated review costs of 25 percent of the estimated total costs of Bonneville Power Administration (1986) T.1-1 for owner's costs, permits and licenses and environmental impact statement.

5B3. Siting and licensing costs for complete plant include:
- Securing option on land at 15 percent fair market value - Battelle (1982).
- Easements and rights of way, owner's costs, permits and licenses, geotechnical studies and environmental impact statement - Bonneville Power Administration (1986) T.1-1.

Siting and licensing costs for gasifier increment include estimated review costs of 50 percent of the estimated total costs of Bonneville Power Administration (1986) T.1-1 for owner's costs, permits and licenses and environmental impact statement.

5D1. Hold cost rounded to nearest $0.10 kilowatt-hour per year.

6D1. Construction cost components are as follows:
- Land purchase - Bonneville Power Administration (1986) T.6-4.
- Direct construction costs, general facilities - Bonneville Power Administration (1986) T.5-1,-2.
- Direct construction costs, power generation - Bonneville Power Administration (1988) T.5-1,-2.
- Direct construction costs, catalysts and chemicals - Bonneville Power Administration (1988) T.5-1,-2.
- Contingency - 10 percent of direct and indirect costs - Bonneville Power Administration (1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, inc. contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Transmission interconnect - Bonneville estimates.
- Spare parts inventory - Bonneville Power Administration (1986) T.6-4.
- Royalties - Bonneville Power Administration (1986) T.6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Natural gas pipeline - Two miles at $500,000 per mile (Bonneville).
- Start-up costs as noted below.

All costs escalated to January 1988, using Handy-Whitman, 1988 where appropriate, GNP deflator otherwise. Based on rated capacity; rounded to the nearest $10 per kilowatt.

Start-up cost components are as follows:
- One month of fixed operating and maintenance costs.
- One month of variable operating and maintenance costs.
- One week at full capacity primary fuel cost.
- Two percent of total construction cost.

Table 8-A-4 (cont.)
Coal-Gasification Combined-Cycle Power Plant

6D2. Construction cost components for incremental addition of combined-cycle plant are as follows:

- Direct construction costs, general facilities - Bonneville Power Administration (1986) T.5-3.
- Direct construction costs, power generation - Bonneville Power Administration (1988) T.5-3.
- Direct construction costs, catalysts and chemicals - Bonneville Power Administration (1988) T.5-3.
- Contingency - 10 percent of direct and indirect costs - Bonneville Power Administration (1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, including contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Second 10 mile, 230kV transmission interconnect - Bonneville estimates.
- Spare parts inventory - Bonneville Power Administration (1986) T.6-4.
- Royalties - Bonneville Power Administration (1986) T.6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Start-up costs as noted below.

All costs escalated to January 1988, using Handy-Whitman, 1988 where appropriate, GNP deflator otherwise. Based on total rated capacity. Rounded to the nearest $10 per kilowatt.

Start-up cost components are as follows:

- One month of fixed operating and maintenance costs.
- One month of variable operating and maintenance costs.
- One week at full capacity primary fuel cost.
- Two percent of total construction cost.

Construction cost components for the complete combined cycle phase are as follows:

- Land purchase - Bonneville Power Administration (1986) T.6-4.
- Direct construction costs, general facilities - Bonneville Power Administration (1986) T.5-1,-2,-3.
- Direct construction costs, power generation - Bonneville Power Administration (1988) T.5-1,-2,-3.
- Direct construction costs, catalysts and chemicals - Bonneville Power Administration (1986) T.5-1,-2,-3.
- Contingency - 10 percent of direct and indirect costs - Bonneville Power Administration (1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, including contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Transmission interconnect - Bonneville estimates.
- Spare parts inventory - Bonneville Power Administration (1986) T.6-4.
- Royalties - Bonneville Power Administration (1986) T.6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Natural gas pipeline - Two miles at $500,000 per mile (Bonneville).
- Start-up costs as noted above.

All costs escalated to January 1988, using Handy-Whitman, 1988 where appropriate, GNP deflator otherwise. Based on rated capacity; rounded to the nearest $10 per kilowatt.

6D3. Construction cost components for incremental addition of the gasification plant are as follows:

- Direct construction costs, incremental - Bonneville Power Administration (1986) T.5-2.
- Construction management - 5 percent of direct costs (Bonneville Power Administration/Kaiser(1987)).
- Contingency - 14.9 percent of direct and indirect costs - Bonneville Power Administration (1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, including contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Spare parts inventory - Bonneville Power Administration (1986) T.6-4.
- Royalties - Bonneville Power Administration (1986) T.6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Start-up costs as noted below.

All costs escalated to January 1988, using Handy-Whitman, 1988 where appropriate, GNP deflator otherwise. Based on total rated capacity. Rounded to the nearest $10 per kilowatt.

Startup cost components are as follows:

- One month of fixed operating and maintenance costs.
- One month of variable operating and maintenance costs.
- One week at full capacity primary fuel cost.
- Two percent of total construction cost.

Construction cost components for the complete gasification-combined cycle plant are as follows:

- Land purchase - Bonneville Power Administration (1986) T.6-4.
- Direct construction costs, complete - Bonneville Power Administration (1986) T.5-2.
- Construction management - 5 percent of direct costs (Bonneville Power Administration/Kaiser(1987)).
- Contingency - 13.3 percent of direct and indirect costs - Bonneville Power Administration (1988).
- Owner's costs during construction - 4 percent of direct and indirect costs, including contingency (Pacific Northwest Utilities Conference Committee, 1984).
- Transmission interconnect - Bonneville estimates.
- Spare parts inventory - Bonneville Power Administration (1986) T.6-4.
- Royalties - Bonneville Power Administration (1986) T.6-4.
- Socioeconomic impact mitigation - 1 percent of total direct and indirect plant costs (Coal Options Task Force, 1985).
- Natural gas pipeline - Two miles at $500,000 per mile (Bonneville).
- Start-up costs as noted above.

All costs escalated to January 1988, using Handy-Whitman, 1988 where appropriate, GNP deflator otherwise. Based on rated capacity; rounded to the nearest $10 per kilowatt.

Table 8-A-4 (cont.)
Coal-Gasification Combined-Cycle Power Plant

7A3. Annual fixed costs of purchase and maintenance of unit train rolling stock.

7C1. See SCCT datasheet for derivation of fixed operating and maintenance costs. Rounded to the nearest $0.10 kilowatts per year.

7C2. See CCCT datasheet for derivation of fixed operating and maintenance costs. Rounded to the nearest $0.10 kilowatts per year.

7C3. Fixed operating and maintenance costs include:
- Fixed operating costs - Bonneville Power Administration (1986) T.6-3, escalated to 1988 using Bonneville "JEFOM" index.
- General and administrative costs of 17 percent - Pacific Northwest Laboratories (1985).

Rounded to the nearest $0.10 kilowatts per year.

7G1. See SCCT datasheet for derivation of variable operating and maintenance costs. Rounded to the nearest 0.1 mills per kilowatt-hour.

7G2. See CCCT datasheet for derivation of variable operating and maintenance costs. Rounded to the nearest 0.1 mills per kilowatt-hour.

7G3. Variable operating and maintenance costs include:
- Variable operating costs - Bonneville Power Administration (1986) T.6-3, escalated to 1988 using Bonneville's "JEFOM" index.
- General and administrative costs of 17 percent - Pacific Northwest Laboratories (1985).

Rounded to the nearest 0.1 mills per kilowatt-hour.

7H3. Consumable costs include:
- Consumables - Bonneville Power Administration (1986) T.6-3, escalated to 1988 using Bonneville's "JEFOM" index.
- General and administrative costs of 17 percent - Pacific Northwest Laboratories (1985).

Rounded to the nearest 0.1 mills per kilowatt-hour.

7I3. Credit for elemental sulfur by-product of Selexol sulfur removal process. Sulfur valued at $78.00 per long ton (1988 dollars).

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APPENDIX 8-B

POTENTIALLY DEVELOPABLE HYDROPOWER SITES

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
00044-00	Hugh L. Cooper	WA	051	1.00	0.60	0.60	I	0	22.371	22.380	13.428
01815-03	Mahoney Springs Minor	MT	053	1.00	0.60	0.60	F	0	0.004	0.001	0.001
02151B00	Beaver Creek Hydroelectric	WA	007	1.00	0.80	0.80	I	4,781	14.000	7.000	5.600
02316B00	E.F. Griffin Creek	WA	033	0.65	0.75	0.65	O	0	29.381	20.566	13.409
02316C00	Carnation	WA	033	0.65	0.75	0.65	O	6,102	34.100	17.050	11.117
02494A02	White River	WA	053	0.69	0.90	0.69	J	6,050	14.000	9.532	6.598
02507A00	Flathead	MT	089	1.00	0.60	0.60	L	0	120.000	67.831	40.699
02507B00	Flathead 2	MT	047	1.00	0.60	0.60	L	0	120.000	45.662	27.397
02526-13	Sullivan Lake Dam	WA	051	1.00	0.85	0.85	F	2,664	13.600	7.050	5.992
02657-00	Thunder Creek	WA	073	0.60	0.10	0.10	C	0	1.305	13.014	1.301
02811D03	White Salmon Wallace Bridge	WA	039	0.64	0.10	0.10	F	0	30.000	12.000	1.200
02811G03	White Salmon Conduit	WA	039	0.91	0.20	0.20	J	0	42.000	29.400	5.880
02833-13	Cowlitz Falls	WA	041	1.00	0.99	0.99	C	4,534	70.000	30.502	30.197
02844-01	Tumwater	WA	007	0.69	0.25	0.25	G	0	4.000	2.511	0.628
02899-03	Milner	ID	083	1.00	0.95	0.95	P	2,636	43.650	16.210	15.400
02952-21	Gem State	ID	011	1.00	1.00	0.95	I	4,023	22.300	14.283	13.569
02959-17	South Fork Tolt	WA	033	0.55	0.95	0.55	D	5,027	15.000	8.596	4.737
02973-04	Island Park	ID	043	0.92	0.99	0.92	J	0	4.800	1.347	1.239
03073-01	Clifford Rosenbalm	ID	015	1.00	0.92	0.92	D	0	0.008	0.003	0.003
03109-01	Blue River	OR	039	0.92	0.90	0.90	J	4,938	14.650	3.930	3.537
03111-01	Dorena	OR	039	0.70	0.20	0.20	M	0	2.900	1.689	0.338
03112B02	Minto 2A Powerhouse B	OR	047	1.00	0.10	0.10	O	7,702	32.770	16.233	1.623
03210-01	Gold Hill	OR	029	0.56	0.60	0.56	D	1,366	3.000	2.540	1.425
03239A09	Koma Kulshan	WA	073	0.50	0.95	0.50	F	1,770	5.600	4.154	2.096
03239B09	Koma Kulshan-Sandy Creek	WA	073	0.50	0.95	0.50	F	2,263	5.600	4.154	2.096
03257-05	Zillah Wasteway	WA	077	0.54	0.92	0.54	D	4,466	11.900	3.379	1.832
03347-01	Sunset Falls Water Power Plant	WA	061	0.55	0.20	0.20	D	0	7.500	7.192	1.438
03378-00	Ochoco Project	OR	013	0.93	0.20	0.20	A	0	1.600	0.457	0.091
03385-02	Oxbow Ranch	ID	059	0.92	0.25	0.25	D	10,366	1.800	1.370	0.342
03403-00	Mora Canal Drop	ID	001	1.00	0.95	0.95	P	5,815	1.900	0.926	0.880
03466A01	Columbia Southern Canal	OR	017	1.00	0.30	0.30	P	0	3.200	1.573	0.472
03466B01	Columbia Southern Canal 2	OR	017	1.00	0.30	0.30	P	6,095	3.200	1.573	0.472
03466C01	Columbia Southern Canal	OR	017	0.92	0.25	0.25	A	7,801	2.400	1.180	0.295
03473-13	North Canal Dam	OR	017	0.91	0.90	0.90	G	3,875	2.825	0.809	0.728
03486-01	Easton Dam	WA	037	0.61	0.92	0.61	D	4,283	1.500	0.840	0.513
03489-01	Roza Dam	WA	037	0.71	0.60	0.60	A	4,686	2.400	1.573	0.944
03560-01	Wickiup	OR	017	0.91	0.90	0.90	G	3,950	7.000	2.979	2.682
03571-08	Central Oregon Siphon	OR	017	1.00	0.60	0.60	P	2,953	5.500	3.209	1.925
03672-00	Horn Rapids Water Power	WA	005	0.69	0.25	0.25	A	32,494	1.395	0.822	0.205
03701-01	Tieton	WA	077	0.70	0.90	0.70	G	3,099	13.600	5.651	3.937
03717-00	Ringold Wasteway	WA	021	1.00	0.30	0.30	P	3,350	3.100	1.228	0.368

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
03784-00	Bend Diversion Dam	OR	017	0.91	0.20	0.20	G	10,256	2.300	0.662	0.132
03827-00	Haystack	OR	031	1.00	0.30	0.30	P	0	2.500	1.027	0.308
03828A00	North Unit Canal Mile 45	OR	031	1.00	0.30	0.30	P	2,591	2.200	1.256	0.377
03828B00	North Unit Canal Mile 51	OR	031	1.00	0.30	0.30	P	3,293	1.900	1.027	0.308
03840-01	Unity	OR	001	0.95	0.25	0.25	G	11,487	0.500	0.171	0.043
03867-01	McKay Dam	OR	059	0.97	0.25	0.25	G	4,658	2.500	0.674	0.168
03913-01	Thunder Creek	WA	057	0.90	0.85	0.85	F	1,758	9.425	5.800	4.930
03918-02	Gold Ray	OR	029	0.68	0.20	0.20	M	7,452	7.200	0.936	0.187
03975-00	Deschutes Main Canal Mile 45	OR	031	1.00	0.20	0.20	P	0	4.000	1.393	0.279
03989-00	Savage Rapids Diversion Dam	OR	029	0.68	0.20	0.20	J	5,292	9.400	4.646	0.929
03991-06	Cross Cut Diversion	ID	043	0.91	0.95	0.91	G	5,351	1.754	1.239	1.132
04061-00	Eagle Creek	OR	001	1.00	0.30	0.30	P	0	1.800	1.142	0.342
04159-00	Magic Springs	ID	047	1.00	0.20	0.20	S	0	2.531	2.278	0.456
04160-02	Rangen Research	ID	047	1.00	0.30	0.30	P	0	0.250	0.179	0.054
04188-01	John W. Jones, Jr.	ID	047	1.00	0.92	0.92	D	0	0.105	0.111	0.102
04217-00	Rock Creek	WA	045	1.00	0.10	0.10	F	9,196	1.800	0.696	0.070
04220-01	Park Creek	WA	073	1.00	0.85	0.85	F	3,984	1.900	1.062	0.902
04227-00	Snake River Trout	ID	047	1.00	0.20	0.20	S	0	0.150	0.138	0.028
04243-00	Saddle Springs	ID	047	1.00	0.20	0.20	S	0	0.100	0.085	0.017
04269-00	Manson Hydroelectric Project	WA	007	0.95	0.25	0.25	D	0	1.800	1.621	0.405
04295-00	Aldrich Creek	WA	073	1.00	0.10	0.10	F	5,088	0.575	0.394	0.039
04308-01	Mud Mountain-White River	WA	033	0.69	0.25	0.25	G	0	5.800	2.968	0.742
04358-00	Scooteney Inlet	WA	021	1.00	0.30	0.30	P	8,515	2.800	1.142	0.342
04408-00	Mill City Diversion	OR	047	0.53	0.25	0.25	D	4,219	60.000	30.137	7.534
04435-05	Damnation Peak	WA	057	1.00	0.60	0.60	F	3,333	5.000	2.127	1.276
04458A04	Middle Fork Irrig. Dist. PH 1	OR	027	1.00	1.00	0.60	M	3,466	2.130	1.724	1.034
04458B04	Middle Fork Irrig. Dist. PH 2	OR	027	1.00	1.00	0.60	M	7,315	0.593	0.475	0.285
04458C04	Pressure Reducing Station 1	OR	027	1.00	1.00	0.60	M	2,232	0.399	0.367	0.220
04458D04	Pressure Reducing Station 2	OR	027	1.00	1.00	0.60	S	0	0.236	0.217	0.130
04458E04	Middle Fork Irrig. Dist. PH 3	OR	027	1.00	1.00	0.60	S	0	0.584	0.395	0.237
04458F04	Pressure Reducing Station 3	OR	027	1.00	1.00	0.60	M	7,303	0.078	0.071	0.043
04458G04	Pressure Reducing Station 4	OR	027	1.00	1.00	0.60	S	0	0.092	0.084	0.051
04458H04	Pressure Reducing Station 5	OR	027	1.00	1.00	0.60	M	136,223	0.027	0.008	0.005
04458I04	Pressure Reducing Station 7	OR	027	1.00	1.00	0.60	S	0	0.077	0.002	0.001
04458J04	Pressure Reducing Station 6	OR	027	1.00	1.00	0.60	M	8,085	0.062	0.017	0.010
04479-00	Howard Prairie Hydroelectric	OR	029	0.94	0.25	0.25	A	18,688	0.224	0.148	0.037
04507-00	Lost Lake	WA	037	1.00	0.10	0.10	F	6,063	2.000	0.639	0.064
04539-01	Clear Lake Hydro Project	WA	077	1.00	0.60	0.60	A	4,128	1.230	0.445	0.267
04574A06	Three Lynx Creek	OR	005	0.58	0.95	0.58	F	1,001	0.565	0.203	0.119
04574B06	Three Lynx Creek	OR	005	0.65	0.95	0.65	D	2,560	0.565	0.079	0.052
04586-06	Swamp Creek	WA	073	0.76	0.95	0.76	F	3,877	3.500	1.712	1.305

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
04587-07	Ruth Creek	WA	073	0.65	0.95	0.65	F	4,402	2.800	1.313	0.856
04606-01	Little Rattler Hydro Project	WA	077	0.73	0.25	0.25	G	0	12.400	6.804	1.701
04656-02	Arrowrock Dam	ID	039	0.94	0.90	0.90	G	3,959	60.000	19.132	17.219
04698-01	Nevada Creek	MT	077	1.00	0.25	0.25	G	0	1.480	0.320	0.080
04709-00	Lake Como	MT	081	1.00	0.20	0.20	J	9,260	0.570	0.320	0.064
04710-00	Potholes Canal Chute 1158	WA	001	1.00	0.20	0.20	P	4,869	7.630	3.105	0.621
04711-01	Potholes E Canal Sta. 1720+44	WA	021	1.00	0.30	0.30	P	0	0.690	0.297	0.089
04712-00	Dry Falls Dam Canal	WA	025	1.00	0.20	0.20	M	5,427	20.860	9.418	1.884
04732-00	Applegate Lake	OR	029	0.95	0.60	0.60	J	3,302	9.000	4.292	2.575
04748-00	Potholes Canal Chute 3480&43	WA	021	1.00	0.20	0.20	P	0	10.150	4.292	0.858
04750-02	Eltopia Branch Canal 625+90	WA	021	1.00	0.95	0.95	P	3,299	0.682	0.352	0.334
04759-00	West Canal Station 1992+00	WA	025	1.00	0.20	0.20	P	4,269	9.120	3.858	0.772
04763-01	EL 85 Station 125+25	WA	001	1.00	0.30	0.30	P	0	0.400	0.148	0.045
04764-01	EL 68 Station 31+00	WA	001	1.00	0.30	0.30	P	0	0.420	0.160	0.048
04765-01	EL 68 Station 65+54.65	WA	001	1.00	0.30	0.30	P	0	0.390	0.148	0.045
04766-01	EL 68 Station 135+76.24	WA	001	1.00	0.30	0.30	P	0	0.350	0.126	0.038
04768-01	EL 85 Station 140+10	WA	001	1.00	0.30	0.30	P	0	0.440	0.160	0.048
04776-01	Experimental Forest Hyd. Proj.	ID	017	1.00	0.10	0.10	F	21,439	0.100	0.048	0.005
04778-01	Morris Creek	ID	017	1.00	0.10	0.10	F	22,980	0.200	0.102	0.010
04780-00	Keokee Creek	ID	017	1.00	0.10	0.10	F	45,106	0.100	0.043	0.004
04858-00	Arena Drop	ID	027	1.00	0.95	0.95	P	0	0.540	0.188	0.179
04885-20	Twin Falls	WA	033	0.68	0.95	0.68	F	3,609	20.000	8.801	5.985
04886-02	Sand Hollow	WA	025	1.00	0.30	0.30	P	0	1.700	0.993	0.298
04887-02	CCL4 Hydroelectric Project	WA	025	1.00	0.30	0.30	P	0	0.600	0.354	0.106
04890-01	Bumping Lake	WA	077	0.69	0.25	0.25	G	2,108	31.000	18.493	4.623
04905-03	Big Lost River	ID	037	0.94	0.60	0.60	M	10,648	3.000	0.491	0.295
04948-02	Thief Valley	OR	061	0.94	0.60	0.60	G	0	0.712	0.331	0.199
05038-00	Main Canal 6	ID	001	1.00	0.95	0.95	S	8,554	1.200	0.480	0.456
05039-00	Golden Gate	ID	027	1.00	0.95	0.95	S	0	0.700	0.313	0.298
05040-00	Fargo Drop 2	ID	027	1.00	0.95	0.95	P	15,955	0.175	0.076	0.072
05041-00	Main Canal 10	ID	027	1.00	0.95	0.95	P	12,165	0.500	0.241	0.229
05042-00	Fargo Drop 1	ID	027	1.00	0.95	0.95	P	5,709	0.650	0.277	0.263
05043-00	Waldvogel Bluff	ID	001	1.00	0.95	0.95	P	14,581	0.300	0.130	0.124
05056-00	Low Line 8	ID	027	1.00	0.95	0.95	P	8,611	0.385	0.175	0.166
05074-06	Mill Creek	OR	019	0.49	0.95	0.49	F	3,296	10.500	3.702	1.830
05094-01	Barnum Creek	MT	053	0.91	0.10	0.10	F	12,409	0.300	0.150	0.015
05097-01	Lime Creek	MT	047	1.00	0.10	0.10	F	24,366	0.100	0.057	0.006
05098-00	Hall Creek	MT	047	0.99	0.10	0.10	F	4,736	0.400	0.238	0.024
05100-01	Indian Springs	MT	053	0.96	0.10	0.10	F	6,009	0.375	0.169	0.017
05101-01	Deep Creek	WA	065	1.00	0.10	0.10	F	12,172	0.150	0.084	0.008
05102-01	Brush Creek	MT	053	1.00	0.10	0.10	F	7,833	0.100	0.057	0.006

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
05104-01	Ruby Creek	MT	053	0.99	0.10	0.10	F	5,412	0.300	0.148	0.015
05106-01	Highland Creek	ID	021	1.00	0.10	0.10	F	9,930	0.150	0.080	0.008
05107-01	Spruce Creek Water Power	ID	021	1.00	0.10	0.10	F	13,333	0.200	0.087	0.009
05108-01	Curley Creek	ID	021	0.88	0.60	0.60	F	3,597	0.500	0.285	0.171
05109-01	Hellroaring Creek	ID	021	1.00	0.10	0.10	F	16,043	0.125	0.065	0.007
05110-01	Curtis Creek	ID	017	0.98	0.10	0.10	F	16,095	0.050	0.032	0.003
05112-01	Falls Creek	ID	017	0.86	0.10	0.10	F	13,518	0.100	0.056	0.006
05113-01	Canyon Creek	ID	017	0.86	0.10	0.10	F	22,637	0.075	0.033	0.003
05116-01	Tieton Canal Drop	WA	077	1.00	0.30	0.30	P	3,735	10.000	3.002	0.901
05208A02	Lower Crow Creek	MT	047	1.00	0.20	0.20	G	0	1.000	0.500	0.100
05241-01	Wallace Creek Hydro Project	WA	073	1.00	0.20	0.20	O	8,647	3.000	1.484	0.297
05242-01	Warm Creek	WA	073	1.00	0.10	0.10	F	0	3.200	1.484	0.148
05278-03	N. Fork Flume Creek Hyd Proj.	WA	051	1.00	0.87	0.87	D	0	0.100	0.060	0.052
05279-05	Birch Creek	WA	073	1.00	1.00	0.87	D	0	0.010	0.007	0.006
05290-01	Pugh Creek	WA	061	0.98	0.10	0.10	F	4,943	2.800	1.427	0.143
05299-00	Ana Springs	OR	037	0.82	0.25	0.25	D	5,901	0.350	0.251	0.063
05301A00	Drews 2	OR	037	1.00	0.30	0.30	P	0	0.300	0.104	0.031
05301B00	Drews 1	OR	037	1.00	0.30	0.30	P	8,771	0.186	0.078	0.024
05341-01	Mineral Butte	WA	061	0.51	0.90	0.51	F	0	5.000	2.235	1.145
05349-00	Swift Creek	WA	073	0.98	0.85	0.85	F	3,478	17.500	6.279	5.337
05364-00	Deschutes-Tumwater	WA	067	0.70	0.60	0.60	G	7,121	2.500	0.890	0.534
05376-06	Horseshoe Bend	ID	015	0.63	0.95	0.63	F	4,043	9.500	5.959	3.730
05396-00	Fairwell Bend	OR	029	0.83	0.10	0.10	F	0	3.100	1.998	0.200
05407-00	Oakley Dam	ID	031	0.97	0.25	0.25	G	0	0.836	0.325	0.081
05409-00	C. Ben Ross Dam	ID	003	0.98	0.25	0.25	G	17,503	2.050	0.394	0.099
05415-00	Trail Creek	ID	013	0.94	0.25	0.25	G	0	0.300	0.150	0.038
05418-01	Big Creek	WA	057	0.98	0.60	0.60	F	3,211	17.500	6.621	3.973
05454-00	Sheep Creek Falls	WA	065	0.51	0.60	0.51	L	1,143	4.900	3.430	1.736
05467-01	Little North Fork	MT	053	0.99	0.10	0.10	F	0	0.150	0.077	0.008
05468-01	Flower Creek	MT	053	0.99	0.10	0.10	F	9,952	0.400	0.190	0.019
05470-01	North Meadow Creek	MT	053	0.97	0.10	0.10	F	11,084	0.150	0.076	0.008
05471-02	Upper Tenmile Creek	MT	053	0.91	0.10	0.10	F	27,676	0.300	0.110	0.011
05475-01	O'Brian Creek	MT	053	0.89	0.10	0.10	F	10,839	0.250	0.120	0.012
05476-09	Lower Tenmile Creek	MT	053	0.91	0.10	0.10	F	28,091	0.200	0.090	0.009
05477-01	Whitetail Creek	MT	053	1.00	0.10	0.10	F	15,790	0.050	0.021	0.002
05478-00	Boulder Creek	MT	053	0.89	0.10	0.10	F	5,783	0.750	0.367	0.037
05479-01	Camp Creek	MT	053	0.78	0.10	0.10	F	11,893	0.225	0.095	0.009
05480-01	Pheasant Creek	MT	053	1.00	0.10	0.10	F	11,135	0.075	0.050	0.005
05481-01	Middle Parsnip Creek	MT	053	1.00	0.10	0.10	F	114,133	0.075	0.037	0.004
05482-01	Gold Creek	MT	053	1.00	0.10	0.10	F	29,471	0.200	0.064	0.006
05483-01	Flat Creek	MT	053	1.00	0.10	0.10	F	31,652	0.150	0.080	0.008

Table 8-B-1
Potentially Developable Hydropower Sites[a]

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05484-01	Sutton Creek	MT	053	1.00	0.10	0.10	F	18,676	0.260	0.153	0.015
05485-00	Sullivan Creek	MT	053	0.89	0.10	0.10	F	6,415	0.500	0.264	0.026
05486-01	Arbo Creek	MT	053	1.00	0.10	0.10	F	5,880	0.230	0.114	0.011
05487-01	Independence Creek	MT	053	1.00	0.10	0.10	F	12,776	0.100	0.050	0.005
05488-01	Alexander Creek	MT	053	1.00	0.10	0.10	F	13,365	0.060	0.036	0.004
05489-01	Cyclone Creek	MT	053	1.00	0.10	0.10	F	9,156	0.150	0.064	0.006
05491-01	Cadette Creek	MT	053	1.00	0.10	0.10	F	11,255	0.200	0.071	0.007
05497-04	Falls Creek Small Hydro Proj.	WA	009	1.00	1.00	0.10	F	6,242	0.200	0.160	0.016
05498-00	Kaster Riverview	ID	083	1.00	0.90	0.90	F	0	0.316	0.315	0.283
05507A00	Crooked River (Mile 2)	OR	017	1.00	0.30	0.30	P	0	2.200	0.970	0.291
05507B00	Crooked River (Station 688)	OR	017	1.00	0.30	0.30	P	0	1.400	0.674	0.202
05507C00	Crooked River (C)	OR	017	1.00	0.30	0.30	P	0	10.700	2.694	0.808
05513-00	Napoleon Gulch	MT	053	1.00	0.10	0.10	F	10,373	0.125	0.060	0.006
05517-01	Scout Creek	MT	047	1.00	0.10	0.10	F	0	0.407	0.281	0.028
05521-02	Porcupine Creek	MT	047	0.99	0.10	0.10	F	4,446	0.259	0.179	0.018
05522-02	Bethal Creek	MT	047	1.00	0.10	0.10	F	3,634	0.263	0.182	0.018
05525-02	Cedar Creek	MT	047	0.89	0.10	0.10	F	0	0.377	0.260	0.026
05544-00	Tomyhoi Creek	WA	073	1.00	0.10	0.10	F	6,783	3.200	1.484	0.148
05545-02	White Salmon Creek	WA	073	1.00	0.82	0.82	F	6,716	1.300	0.765	0.627
05554-01	Iron Mountain Project	WA	057	0.64	0.90	0.64	F	3,653	1.620	0.836	0.539
05556-01	South Fork Woodward Creek	MT	047	0.99	0.10	0.10	F	4,093	1.411	0.974	0.097
05558-01	Cold Creek	MT	063	0.91	0.10	0.10	F	5,041	0.929	0.641	0.064
05562-01	Upper Oak Grove Fork	OR	005	0.76	0.10	0.10	F	3,339	10.500	7.420	0.742
05584-01	Coffee Pot	OR	037	0.61	0.10	0.10	L	0	3.750	1.027	0.103
05600-01	Springfield Canal	OR	039	1.00	0.30	0.30	P	0	0.300	0.263	0.079
05608-00	McCully Creek	OR	063	1.00	0.60	0.60	P	6,416	0.200	0.084	0.050
05616-01	Icicle Creek	WA	007	0.98	0.10	0.10	F	1,181	80.000	34.247	3.425
05617A00	Meadows Waterpower (A)	WA	059	1.00	0.10	0.10	F	2,830	10.000	5.936	0.594
05617B00	Meadows Waterpower (B)	WA	059	1.00	0.10	0.10	F	0	31.000	17.808	1.781
05650-02	Kanaka Creek	ID	047	1.00	0.60	0.60	P	12,250	0.090	0.046	0.027
05653-00	Mission Dam	MT	047	1.00	0.20	0.20	J	10,950	0.300	0.148	0.030
05654-01	Hubbart Dam	MT	029	0.99	0.20	0.20	J	41,394	0.250	0.070	0.014
05655A00	Post Creek (A)	MT	047	1.00	0.20	0.20	A	0	0.400	0.153	0.031
05655B00	Post Creek (B)	MT	047	1.00	0.20	0.20	G	5,895	1.500	0.793	0.159
05656A00	Dry Creek (A)	MT	047	1.00	0.20	0.20	G	13,155	0.500	0.217	0.043
05656B00	Dry Creek (B)	MT	047	1.00	0.20	0.20	P	0	5.000	0.234	0.047
05658-00	Stahl Creek	MT	053	0.97	0.10	0.10	F	4,690	0.750	0.518	0.052
05659-00	Williams Creek	MT	053	0.99	0.10	0.10	F	4,393	1.300	1.036	0.104
05660-00	Deep Creek	MT	053	0.99	0.10	0.10	F	9,963	1.500	1.053	0.105
05661-00	Kopsi Creek	MT	053	1.00	0.10	0.10	F	4,838	0.500	0.345	0.035
05663-01	Foundation Creek	MT	053	0.99	0.10	0.10	F	6,929	0.350	0.242	0.024

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05664-00	Blue Sky Creek	MT	053	0.97	0.10	0.10	F	6,046	1.000	0.690	0.069
05699-00	Victor Falls	WA	053	0.73	1.00	0.73	M	0	0.125	0.070	0.052
05711-01	Nespelem River	WA	047	1.00	0.25	0.25	D	2,574	1.800	1.027	0.257
05719-00	Bond Creek	MT	047	0.96	0.20	0.20	F	0	0.367	0.254	0.051
05733-00	Groom Creek	MT	047	1.00	0.10	0.10	F	4,965	0.376	0.260	0.026
05783-00	Woodward Tributary	MT	047	0.99	0.10	0.10	F	13,485	0.200	0.100	0.010
05819-00	Johnson Creek	WA	061	1.00	0.10	0.10	F	4,503	4.700	1.781	0.178
05823-00	Boulder Creek	OR	039	0.87	0.10	0.10	F	2,553	4.900	2.694	0.269
05825-00	May Creek	WA	061	1.00	0.10	0.10	F	3,665	0.800	0.571	0.057
05829-01	Beckler River Hydro Project	WA	061	0.50	0.90	0.50	F	6,152	3.000	2.100	1.060
05830-02	New Willamette Falls	OR	005	0.68	0.25	0.25	G	0	60.000	34.932	8.733
05851-00	Black Creek	OR	039	0.93	0.20	0.20	M	0	9.000	4.589	0.918
05853-00	Olney Creek Falls	WA	061	0.70	0.60	0.60	G	2,590	1.500	1.062	0.637
05877-00	Dodge Creek	MT	053	0.76	0.10	0.10	F	13,210	0.760	0.524	0.052
05882-00	Roaring Creek	WA	007	1.00	0.10	0.10	F	5,491	0.600	0.282	0.028
05883-00	Resort Creek	WA	037	1.00	0.10	0.10	F	6,106	0.350	0.165	0.017
05884-00	Rocky Run Creek	WA	037	1.00	0.10	0.10	F	7,851	0.525	0.207	0.021
05898-00	Bliss Diversion	ID	047	1.00	0.30	0.30	P	0	0.550	0.331	0.099
05899-00	Mill Creek Waterpower Project	WA	037	1.00	0.10	0.10	F	0	0.225	0.100	0.010
05903-01	Black Canyon	ID	045	0.91	0.45	0.45	M	0	24.000	7.078	3.185
05926A02	N. Fork Snoqualmie River (A)	WA	033	0.73	0.60	0.60	C	37	14.800	7.400	4.440
05926B02	N. Fork Snoqualmie River (B)	WA	033	0.73	0.60	0.60	I	0	20.000	10.000	6.000
05932-00	Crane Creek	MT	047	0.91	0.10	0.10	F	4,819	0.210	0.145	0.014
05939-00	Granite Creek Power Project	WA	019	1.00	0.60	0.60	G	0	0.050	0.040	0.024
05957-01	Reed Road Pump Generator	OR	027	1.00	0.95	0.95	S	0	0.160	0.086	0.081
05978-03	Diamond Creek	WA	073	1.00	0.90	0.90	F	5,677	0.350	0.171	0.154
05979-01	I Coulee Hydroelectric	ID	083	1.00	0.60	0.60	F	5,075	0.299	0.186	0.111
05982-00	Smith Creek Project	WA	073	0.64	0.90	0.64	F	16,697	0.093	0.054	0.035
06003-00	Watson Creek	WA	045	1.00	0.10	0.10	F	7,264	0.973	0.411	0.041
06007-00	Boulder Creek	WA	045	1.00	0.10	0.10	F	3,953	3.000	1.438	0.144
06089-03	Skate Creek	WA	041	0.71	0.90	0.71	F	2,428	5.000	3.653	2.601
06092-05	Butter Creek	WA	041	0.70	0.90	0.70	F	0	2.785	1.210	0.842
06138-11	Pine Creek	MT	053	1.00	0.60	0.60	F	6,471	0.350	0.138	0.083
06143-00	Mt. Rose Hydro Project	WA	045	1.00	0.10	0.10	F	4,364	0.200	0.199	0.020
06151-06	Cabin Creek	WA	031	1.00	0.95	0.95	F	2,948	2.890	1.355	1.287
06165-00	Dixie Waterworks	WA	041	1.00	0.60	0.60	F	0	0.001	0.001	0.000
06169-00	Dupris Hydro	WA	073	1.00	0.60	0.60	F	0	0.009	0.006	0.003
06221-01	Black Creek	WA	033	1.00	0.95	0.95	F	8,659	3.700	1.199	1.139
06231-01	Wardenhoff Creek	ID	085	1.00	0.90	0.90	F	3,425	0.392	0.120	0.108
06247-00	Upper Big Creek	WA	057	0.98	0.60	0.60	F	2,534	2.700	1.397	0.838
06248-01	Waste Waterway 68D Dike 9	WA	001	1.00	0.30	0.30	P	12,883	0.250	0.114	0.034

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06254-00	Lower Big Creek	WA	057	0.98	0.60	0.60	F	0	3.610	1.842	1.105
06259-00	Little Squaw Creek	ID	045	0.98	0.20	0.20	F	0	0.800	0.320	0.064
06260-01	Shafer Creek	ID	015	0.86	0.60	0.60	F	0	0.150	0.060	0.036
06263-01	Waste Waterway 68D Dike 8	WA	001	1.00	0.30	0.30	P	0	0.190	0.094	0.028
06264-01	Waste Waterway 68D Dike 6	WA	001	1.00	0.30	0.30	P	0	0.220	0.108	0.033
06271B00	White Water Ranch	ID	047	1.00	0.90	0.90	F	59,523	0.030	0.022	0.020
06272-00	Grade Creek Project	WA	057	1.00	0.60	0.60	F	3,856	3.240	1.651	0.990
06273-00	Big Creek	WA	057	0.98	0.60	0.60	F	7,067	2.600	1.336	0.801
06283B02	Twin Lks/Goose Lk/Brundage R	ID	003	0.49	0.90	0.49	F	11,997	0.250	0.126	0.061
06283C02	Twin Lks/Goose Lk/Brundage R	ID	003	0.69	0.60	0.60	M	7,577	0.985	0.492	0.295
06283D02	Twin Lks/Goose Lk/Brundage R	ID	003	0.49	0.90	0.49	F	3,763	2.800	1.400	0.681
06286-00	Little Wolf Creek	WA	047	1.00	0.30	0.30	P	0	0.100	0.100	0.030
06287-02	Lena Creek	WA	031	1.00	0.60	0.60	F	2,485	5.000	2.671	1.603
06301-00	Trout Creek	WA	061	0.50	0.90	0.50	F	5,187	5.000	1.884	0.950
06316-00	Carroll Creek	WA	033	1.00	0.20	0.20	I	2,629	0.900	0.884	0.177
06331-03	McGowan Properties	WA	049	1.00	0.87	0.87	D	0	0.030	0.022	0.019
06343-00	Dinner Creek	OR	005	0.89	0.10	0.10	F	10,129	0.568	0.252	0.025
06348-01	Harlan Creek	WA	033	1.00	0.60	0.60	F	0	2.000	1.370	0.822
06381-00	Little Goose Creek	ID	003	1.00	0.82	0.82	F	3,146	0.730	0.307	0.252
06382-00	Lemah Creek	ID	085	1.00	0.60	0.60	F	2,751	0.559	0.264	0.158
06385-00	Wind River	WA	059	0.60	0.25	0.25	D	0	0.500	0.197	0.049
06400-00	Mann Creek	ID	087	0.95	0.25	0.25	G	10,115	0.365	0.160	0.040
06401-00	Tyee/Jumbo Basin	ID	085	1.00	0.60	0.60	F	3,072	0.741	0.298	0.179
06406-01	Gerber Reservoir	OR	035	0.95	0.25	0.25	A	0	0.190	0.095	0.024
06407-00	KID Upper "C" Drop	OR	035	1.00	0.30	0.30	P	0	0.760	0.308	0.092
06415-03	Bagley Creek	WA	073	1.00	0.60	0.60	F	4,078	3.000	1.427	0.856
06422-06	Wyeth	OR	027	0.64	0.90	0.64	F	5,571	1.000	0.308	0.199
06434-06	Ditch Creek	ID	085	1.00	0.85	0.85	F	3,826	0.440	0.137	0.116
06437-05	Upper Glacier Creek	WA	073	0.50	0.90	0.50	F	5,776	3.300	1.815	0.910
06444-02	Cedar Creek	MT	053	0.97	0.90	0.90	F	553	1.300	1.300	1.170
06460-00	Dry Creek	OR	001	1.00	0.95	0.95	P	0	0.421	0.235	0.224
06461-08	Morse Creek	WA	009	1.00	1.00	0.95	D	3,106	0.465	0.348	0.331
06468-01	Star Creek	MT	053	0.97	0.60	0.60	F	0	2.000	0.571	0.342
06472-01	King Hill/Draper	ID	039	1.00	0.95	0.95	P	0	0.175	0.088	0.084
06477-01	Lilborn Creek	WA	041	1.00	0.60	0.60	F	2,911	0.861	0.651	0.390
06481-00	Beyer	OR	005	0.97	1.00	0.97	G	0	0.024	0.008	0.007
06496-00	Skykomish Tributaries Project	WA	061	1.00	0.10	0.10	F	4,410	3.260	1.631	0.163
06504-04	Upper Found Creek	WA	057	0.90	0.82	0.82	F	3,985	1.870	0.936	0.768
06505-00	Howard Creek	WA	061	1.00	0.10	0.10	I	5,089	3.450	1.727	0.173
06506-00	Excelsior Creek	WA	061	1.00	0.10	0.10	F	2,795	1.630	0.816	0.082
06510-00	Trout Creek Water Power	ID	021	0.77	0.10	0.10	F	0	3.780	1.941	0.194

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06524-05	Elk Creek Falls	ID	035	0.62	0.85	0.62	F	2,515	4.320	2.167	1.344
06538-00	Helena Creek	WA	061	1.00	0.20	0.20	F	4,840	1.810	1.084	0.217
06552-08	Sprague River	OR	035	0.66	0.95	0.66	F	6,073	1.119	0.656	0.433
06558-00	Sullivan Springs	ID	047	1.00	0.60	0.60	F	6,168	0.170	0.118	0.071
06568-04	Grave Creek 2	OR	033	0.49	0.95	0.49	F	7,154	2.500	1.267	0.627
06582-00	Woodcock Creek	OR	005	0.87	0.60	0.60	F	0	0.082	0.046	0.027
06600-03	Silver Creek	WA	041	0.75	0.90	0.75	F	0	4.900	3.425	2.562
06616-00	Sky Creek	WA	057	1.00	0.60	0.60	F	0	1.900	1.427	0.856
06636-00	Big Elk Creek YMCA Camp	ID	019	1.00	1.00	0.60	F	0	0.007	0.003	0.002
06654-00	Fall Creek	OR	005	0.82	0.10	0.10	F	0	1.400	0.848	0.085
06656-00	McGee/Elk Creek	OR	027	0.87	0.10	0.10	F	0	1.870	0.928	0.093
06659-00	Sardine Creek	OR	047	0.87	0.10	0.10	F	0	1.720	0.909	0.091
06663-04	KTFI Creek	ID	083	1.00	0.82	0.82	F	20,732	0.034	0.033	0.027
06667-00	Battle Ridge	ID	049	0.51	0.60	0.51	D	5,599	0.908	0.794	0.406
06675-01	Spruce	WA	059	0.69	0.60	0.60	A	3,556	0.385	0.170	0.102
06692-01	Ollalie Creek	OR	043	0.80	0.10	0.10	F	2,000	4.550	3.901	0.390
06707-05	Sheep Falls	ID	043	0.74	0.60	0.60	F	5,936	4.200	2.486	1.492
06709-00	Cortright Creek	WA	041	1.00	0.82	0.82	F	4,162	4.900	2.397	1.966
06711-01	Crystal Springs Hatchery	ID	047	1.00	0.60	0.60	S	7,182	0.200	0.182	0.109
06717-00	Thunder Creek 3	WA	073	0.95	0.82	0.82	F	3,913	5.000	3.699	3.033
06719-00	Thunder Creek 2	WA	073	0.95	0.82	0.82	F	2,995	5.000	3.699	3.033
06737-00	Thunder Creek 1	WA	073	0.95	0.82	0.82	F	6,661	5.000	3.699	3.033
06741-00	Blackfoot Dam	ID	029	0.92	0.25	0.25	G	9,729	1.000	0.685	0.171
06760-00	Oroville-Tonasket Canal	WA	047	1.00	0.20	0.20	P	2,434	2.000	1.438	0.288
06769-00	Sixmile Creek	MT	047	1.00	0.10	0.10	F	5,812	0.200	0.137	0.014
06788-02	Deep Creek	ID	083	0.75	0.82	0.75	F	19,794	0.280	0.127	0.095
06798-00	Tunnel Creek	OR	047	1.00	0.10	0.10	F	27,767	1.100	0.590	0.059
06799-00	Lost Creek	OR	039	1.00	0.10	0.10	F	0	3.200	2.797	0.280
06800-00	White Water Creek	OR	047	0.82	0.10	0.10	F	7,865	3.600	1.901	0.190
06801-02	FID Project 3	OR	027	1.00	1.00	0.10	P	0	1.800	0.850	0.085
06804-01	Downing Creek	OR	043	0.89	0.10	0.10	F	2,936	3.277	1.802	0.180
06824-02	Silver Creek	WA	053	0.58	0.95	0.58	F	4,007	3.800	2.426	1.407
06828-00	Lower Palouse River	WA	021	0.32	0.10	0.10	O	0	50.000	13.402	1.340
06832A00	Basin Creek (A)	MT	093	0.91	0.10	0.10	F	0	0.190	0.076	0.008
06832B00	Basin Creek (B)	MT	093	0.82	0.10	0.10	O	0	0.090	0.063	0.006
06836-00	Dryden	WA	007	1.00	0.20	0.20	P	3,531	4.000	2.511	0.502
06842-14	Wynoochee River	WA	027	0.69	0.95	0.69	G	3,708	10.800	4.811	3.335
06850-00	Cox's Hydro Project	ID	083	0.75	0.90	0.75	F	0	0.300	0.088	0.066
06854-00	Brown's Pond	ID	085	0.96	0.25	0.25	G	0	0.750	0.288	0.072
06857-01	Yakima Diversion Dam	WA	077	0.71	0.25	0.25	A	0	0.650	0.400	0.100
06858-00	Honeymoon Creek	MT	089	0.95	0.10	0.10	F	4,150	0.950	0.329	0.033

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Regul.	Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
06859-00	Bull Run Creek	ID	035	0.98	0.10	0.10	F	0	2.580	1.008	0.101
06874-00	South Fork Eagle Creek	OR	005	1.00	0.10	0.10	F	4,086	6.861	4.498	0.450
06895-01	Fisher Creek	ID	085	0.81	0.60	0.60	F	5,104	5.000	1.461	0.877
06921-00	Dry Ridge	OR	005	1.00	0.10	0.10	F	2,568	1.400	0.878	0.088
06965-00	Hecla Power Project	ID	079	1.00	1.00	0.10	G	0	0.000	0.878	0.088
06978-00	Fern Ridge	OR	039	0.91	0.20	0.20	G	0	2.500	0.822	0.164
06979-00	Huckleberry Creek	OR	039	0.87	0.20	0.20	F	0	5.700	5.575	1.115
06989-01	Little Sardine Creek	OR	047	1.00	0.10	0.10	F	0	0.305	0.153	0.015
07018-00	Goldsborough Creek	WA	045	0.72	0.25	0.25	G	8,563	0.380	0.151	0.038
07028-00	Cottage Grove Dam	OR	039	0.91	0.20	0.20	J	5,997	1.400	0.628	0.126
07032-00	Gresham Brothers Lake Creek 3	ID	079	1.00	0.10	0.10	F	0	0.185	0.126	0.013
07036A00	Stillaguamish Tributaries (A)	WA	061	1.00	0.20	0.20	F	0	1.600	0.799	0.160
07036E00	Stillaguamish Tributaries (E)	WA	061	1.00	0.20	0.20	F	0	1.810	0.905	0.181
07036F00	Stillaguamish Tributaries (F)	WA	061	1.00	0.20	0.20	F	0	2.340	1.171	0.234
07036G00	Stillaguamish Tributaries (G)	WA	061	1.00	0.20	0.20	F	0	3.580	1.790	0.358
07038B00	Wallace-Isabel (B)	WA	061	1.00	0.20	0.20	F	2,572	2.628	2.591	0.518
07039-01	Bob Moore Creek	ID	059	1.00	0.20	0.20	F	28,975	0.550	0.201	0.040
07065-00	Long Lake Dam	WA	043	1.00	0.30	0.30	P	2,247	67.610	30.537	9.161
07074-00	Snowshoe Creek	MT	053	0.89	0.60	0.60	F	0	4.500	2.051	1.231
07075-00	McNary Fish Attraction	WA	005	0.76	0.30	0.30	B	0	7.000	4.680	1.404
07076-00	The Dalles	WA	039	0.77	0.99	0.77	H	3,116	4.200	3.687	2.827
07083-01	Savage Rapids	OR	029	0.68	0.20	0.20	J	0	7.500	3.750	0.750
07089-00	Alfred Teufel Nursery	OR	067	0.91	0.85	0.85	F	10,433	0.040	0.012	0.010
07092-00	P.E. 16.4 Wasteway Hendricks	WA	021	1.00	0.30	0.30	P	4,114	0.790	0.587	0.176
07097-01	Rainbow Creek Hydro	WA	009	1.00	0.95	0.95	P	3,626	3.000	2.100	1.995
07110-00	Boulder Creek	ID	079	1.00	0.10	0.10	F	7,040	0.185	0.126	0.013
07111-01	Wright Creek	WA	027	1.00	0.60	0.60	F	6,740	0.500	0.251	0.151
07134-00	Squirrel Creek	OR	047	0.87	0.20	0.20	F	0	0.510	0.319	0.064
07166-00	Diamond Cogeneration	OR	027	1.00	0.60	0.60	P	0	0.050	0.035	0.021
07174-05	Cottrell	WA	059	0.49	0.99	0.49	I	4,089	3.000	1.142	0.563
07182-06	Davis Creek	WA	041	0.77	0.82	0.77	F	2,422	1.600	0.742	0.570
07184-00	Sorensen	ID	037	0.78	0.10	0.10	F	0	0.030	0.029	0.003
07185-00	NG Rock Creek 5	ID	079	1.00	0.10	0.10	F	0	0.150	0.126	0.013
07214-01	Spring Creek	WA	039	1.00	1.00	0.10	C	0	0.006	0.003	0.000
07215-00	South Prairie Creek	WA	053	0.60	0.20	0.20	D	3,258	5.000	2.255	0.451
07217-01	Valsetz	OR	053	0.64	0.87	0.64	D	0	3.900	1.943	1.241
07225-03	Fall Creek	ID	003	1.00	0.85	0.85	F	5,031	1.091	0.298	0.253
07255-01	Stanton Creek	MT	029	0.81	0.10	0.10	F	8,290	0.100	0.080	0.008
07269-00	Jim Boyd	OR	059	1.00	1.00	0.10	F	16,906	1.095	0.483	0.048
07276-02	Fall Creek	ID	077	0.95	0.60	0.60	F	2,563	0.150	0.137	0.082
07286-00	Beulah (Agency Valley)	OR	045	0.94	0.25	0.25	G	6,591	2.000	0.594	0.148

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
07289-00	Juntura	OR	045	0.93	0.25	0.25	G	6,521	3.000	0.799	0.200
07290-00	Hood River	OR	027	1.00	0.20	0.20	P	0	3.960	2.232	0.446
07294-03	North Fork	OR	029	0.65	0.82	0.65	F	3,288	3.350	2.112	1.373
07311-00	Timberline	OR	005	0.82	0.10	0.10	F	0	0.350	0.314	0.031
07315-01	Curry Ditch	OR	001	1.00	0.60	0.60	P	0	0.420	0.251	0.150
07318-02	Kirtley-York	ID	013	0.76	0.60	0.60	D	0	0.600	0.382	0.229
07322-00	Trail Creek	ID	081	1.00	0.20	0.20	P	4,455	0.450	0.212	0.042
07324-00	Dead Horse Creek	ID	085	1.00	0.60	0.60	F	36,267	0.360	0.148	0.089
07325-00	Rogue River	OR	029	0.69	0.10	0.10	F	0	19.000	12.215	1.221
07368-00	Wagner Enterprises	OR	005	0.72	1.00	0.72	A	0	0.032	0.014	0.010
07390-00	Little Palouse Falls	WA	021	0.55	0.60	0.55	F	6,295	5.000	1.986	1.092
07393-02	Bagley Creek Water	WA	073	1.00	0.60	0.60	F	3,178	2.500	1.199	0.719
07402-00	Dailey Creek	OR	019	1.00	0.60	0.60	F	0	0.300	0.080	0.048
07405-00	Upper Indian Creek	OR	061	1.00	1.00	0.60	F	31,124	0.075	0.065	0.039
07439-00	George 1	ID	043	0.74	0.10	0.10	F	6,168	2.649	1.804	0.180
07440-00	George 2	ID	043	0.74	0.10	0.10	F	5,712	3.098	2.110	0.211
07441-00	George 3	ID	043	0.74	0.10	0.10	F	0	3.547	2.416	0.242
07447-02	Portneuf River	ID	005	0.73	0.99	0.73	I	2,744	0.744	0.445	0.324
07452-01	Clear Creek	OR	001	0.89	0.82	0.82	F	0	0.522	0.459	0.376
07455-00	Triple Creek	WA	061	1.00	0.60	0.60	F	5,080	0.640	0.279	0.167
07533-00	Farmers Irrigation District	OR	027	1.00	0.95	0.95	P	0	2.500	1.484	1.410
07562-00	Tomtit Lake Power Project	WA	061	1.00	0.30	0.30	S	0	0.300	0.228	0.068
07577-00	Burton Creek	WA	041	1.00	1.00	0.30	F	7,175	0.800	0.400	0.120
07589-00	Shingle Creek	ID	049	1.00	0.85	0.85	F	5,790	0.621	0.160	0.136
07491-00	Italian Creek	WA	015	1.00	0.10	0.10	F	0	1.500	0.228	0.023
07598-00	Arrow Creek	WA	057	1.00	0.10	0.10	F	0	0.950	0.380	0.038
07600-00	Iron Creek	WA	057	1.00	0.20	0.20	F	3,309	2.800	1.118	0.224
07601-00	Peek-a-boo Creek	WA	061	1.00	0.10	0.10	F	13,919	0.890	0.356	0.036
07602-01	Loch Katrine	WA	033	1.00	0.20	0.20	F	13,009	1.147	0.459	0.092
07606-00	Harvey Creek	WA	051	1.00	0.10	0.10	F	6,574	0.700	0.490	0.049
07620-00	SMC Lake	WA	033	0.73	0.20	0.20	F	4,579	1.700	0.670	0.134
07627-00	Ashley Creek	MT	029	0.93	0.10	0.10	F	4,318	0.352	0.243	0.024
07640-00	French Cabin Creek	WA	037	1.00	0.20	0.20	N	5,863	2.949	1.180	0.236
07641-00	Black Creek	WA	061	1.00	0.20	0.20	F	3,685	2.040	0.815	0.163
07644-00	Greider Creek Water Power	WA	061	1.00	0.20	0.20	F	6,690	0.860	0.342	0.068
07666-00	Meadow Creek	WA	061	1.00	0.20	0.20	F	0	3.470	1.389	0.278
07668-00	Silver Creek	WA	037	1.00	0.20	0.20	F	0	2.817	1.127	0.225
07672-00	Canyon Creek	WA	053	0.78	0.20	0.20	N	7,221	1.960	0.784	0.157
07675-00	Sloan Peak Water Power Proj	WA	061	1.00	0.20	0.20	F	3,996	1.150	0.460	0.092
07684-00	Leishman Irrigation System	WA	037	1.00	1.00	0.20	S	0	0.032	0.007	0.001
07697-00	Chester Dam	ID	043	0.71	0.60	0.60	D	10,222	0.900	0.674	0.404

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
07719-03	O.J. Power Company	ID	071	1.00	1.00	0.60	F	6,695	0.146	0.152	0.091
07732-00	Mason Dam	OR	001	0.93	0.90	0.90	G	3,267	2.300	0.902	0.812
07741-00	Thorp Creek	WA	037	1.00	0.20	0.20	F	7,583	2.393	0.957	0.191
07786A00	Three Mile Falls 1	OR	059	1.00	0.30	0.30	P	0	5.000	0.463	0.139
07786B00	Three Mile Falls 2	OR	059	1.00	0.30	0.30	P	0	3.700	0.722	0.217
07788-01	Nancy 3 Water Power	WA	051	1.00	0.10	0.10	F	4,945	0.200	0.171	0.017
07806-01	Prospect Creek	MT	089	0.86	0.95	0.86	F	3,535	2.900	0.936	0.807
07817-00	Cummings Hydro Power	ID	059	1.00	0.60	0.60	F	0	0.030	0.012	0.007
07819-01	Lava Creek	ID	023	1.00	0.10	0.10	F	7,384	0.530	0.308	0.031
07829-00	Emigrant Dam	OR	029	0.72	0.90	0.72	M	7,912	1.850	0.628	0.450
07833-00	Gill Creek Hydro Project	WA	007	1.00	0.20	0.20	F	6,380	0.993	0.397	0.079
07834-00	Evans Lake	WA	033	1.00	0.20	0.20	F	8,399	1.005	0.402	0.080
07839-00	Cougar Creek	WA	061	1.00	0.20	0.20	F	6,981	1.334	0.534	0.107
07840-00	Hansen Creek	WA	033	1.00	0.20	0.20	F	5,816	1.340	0.534	0.107
07846-00	Bonneville Fish Attraction	OR	051	0.76	0.20	0.20	B	0	7.600	7.237	1.447
07858-00	Boulder Park	OR	001	1.00	0.60	0.60	F	0	0.600	0.046	0.027
07859-00	Carmen Creek	ID	059	0.88	0.10	0.10	F	8,434	2.300	0.986	0.099
07878-00	Hidden Springs	ID	047	1.00	0.87	0.87	D	10,762	0.073	0.035	0.031
07903-00	Squaw Creek	OR	017	0.66	0.10	0.10	F	0	3.500	2.511	0.251
07926-00	Spread Creek	MT	053	0.89	0.10	0.10	F	7,393	0.700	0.490	0.049
07940-00	Price Creek	WA	073	1.00	0.60	0.60	F	2,020	1.900	1.073	0.644
07978-00	Boulder Creek	MT	039	0.99	0.60	0.60	F	2,406	0.500	0.194	0.116
08040-02	Kinney Lake	OR	063	1.00	0.20	0.20	P	6,104	1.277	0.596	0.119
08043-03	Crow Creek	OR	065	0.74	0.20	0.20	O	8,607	3.350	1.747	0.349
08082-00	Cotten Hydro	WA	041	1.00	0.60	0.60	F	0	0.040	0.020	0.012
08094-02	Pine Creek	OR	001	0.70	0.20	0.20	F	4,338	1.700	1.095	0.219
08120-00	Wallace Creek	ID	059	0.98	0.60	0.60	F	0	0.007	0.007	0.005
08121-00	Deer Creek	ID	015	0.98	0.95	0.95	F	1,414	0.383	0.275	0.261
08128-00	Bob Nydegger Hydro Project	ID	083	0.90	0.20	0.20	J	0	4.702	0.940	0.188
08130-01	Brush Creek	ID	085	1.00	0.20	0.20	F	9,373	2.000	0.571	0.114
08131-00	Box Creek	ID	085	0.98	0.10	0.10	F	10,824	2.000	0.571	0.057
08133-04	East Fork Ditch	ID	003	0.98	0.95	0.95	D	3,145	4.980	1.522	1.446
08151-00	Clearwater Ditch and Chamberlin Pipeline	OR	063	1.00	0.95	0.95	S	0	0.057	0.047	0.045
08183-00	Deer Creek	WA	061	1.00	0.20	0.20	F	1,404	2.600	2.600	0.520
08202-00	Home Project	WA	041	1.00	0.60	0.60	F	0	0.008	0.002	0.001
08229-00	Freeman Creek	ID	059	0.98	0.10	0.10	F	6,066	1.200	0.853	0.085
08250-00	Amy Ranch	ID	023	0.98	0.82	0.82	F	11,389	0.450	0.228	0.187
08251-03	Riser Creek	ID	017	0.88	0.10	0.10	F	7,040	0.500	0.225	0.022
08253-00	Sharrott Creek	MT	081	1.00	0.60	0.60	F	20,255	0.095	0.040	0.024
08279-00	Lincoln Bypass	ID	063	1.00	0.60	0.60	P	2,070	1.960	1.139	0.684

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
08289-08	Noisy Creek	WA	073	0.98	0.95	0.95	F	2,910	10.700	5.057	4.804
08314-00	Deer Creek	WA	061	1.00	0.10	0.10	F	0	2.600	1.541	0.154
08332-00	1146 Wasteway	WA	037	1.00	0.20	0.20	P	0	3.600	0.792	0.158
08375-01	Blind Canyon	ID	047	1.00	1.00	0.20	P	4,958	1.300	0.646	0.129
08379-01	Louie Creek	ID	085	0.84	0.10	0.10	F	7,608	3.600	1.800	0.180
08479-00	Damfino Creek	WA	073	1.00	0.10	0.10	F	4,156	4.300	2.055	0.205
08481-00	Hill-Hagerman	ID	047	1.00	0.60	0.60	S	12,188	0.050	0.050	0.030
08515-00	Hope Creek	OR	063	1.00	0.60	0.60	F	2,773	0.115	0.040	0.024
08523-01	Jug Creek	ID	085	1.00	0.10	0.10	F	9,733	1.500	0.308	0.031
08524-01	Fall Creek	ID	085	1.00	0.10	0.10	F	7,725	3.900	0.799	0.080
08525-01	Boulder Creek	ID	085	0.95	0.10	0.10	F	8,485	4.500	0.890	0.089
08547-00	North Bend	WA	033	0.77	0.10	0.10	F	2,490	7.700	3.938	0.394
08601-01	Jore	MT	047	1.00	0.85	0.85	F	897	1.000	0.362	0.307
08612-01	Geo-Bon 1	ID	063	0.64	0.85	0.64	F	2,252	1.350	0.799	0.511
08643-00	Lower Patterson Creek	ID	059	0.82	0.20	0.20	F	7,164	1.350	0.675	0.135
08646-06	Mink Creek	ID	041	1.00	1.00	0.20	F	2,497	2.750	1.071	0.214
08667-00	Greenwood	ID	053	1.00	0.60	0.60	P	0	2.400	2.352	1.411
08670-00	Prineville	OR	013	0.90	0.20	0.20	G	0	2.900	1.949	0.390
08706-04	Keechelus to Kachess	WA	037	1.00	0.20	0.20	J	0	3.250	2.477	0.495
08790-00	Wishkah	WA	027	1.00	0.95	0.95	S	0	0.330	0.220	0.209
08795-00	Royal Catfish	ID	053	1.00	0.60	0.60	P	0	3.100	2.800	1.680
08804-01	Strawberry Flats	OR	029	0.93	0.20	0.20	M	0	20.000	7.991	1.598
08860-03	Little Gold	MT	039	1.00	1.00	0.20	F	5,017	0.450	0.217	0.043
08864-03	Calligan Creek	WA	033	0.77	0.45	0.45	F	0	5.050	2.020	0.909
08871-00	Marsh Valley	ID	005	1.00	0.60	0.60	P	3,796	1.700	0.813	0.488
08917-00	Phillips Ditch	OR	001	0.87	0.20	0.20	F	8,674	0.260	0.153	0.031
08946-01	Willow Creek	ID	031	1.00	0.20	0.20	F	10,665	0.740	0.308	0.062
08950-04	Twelve Mile Creek	ID	059	0.76	0.10	0.10	F	0	0.450	0.338	0.034
08971-05	Lincoln Bypass	ID	063	1.00	0.95	0.95	P	2,070	1.900	1.139	1.082
09006-02	Tumalo Creek	OR	017	0.76	0.25	0.25	D	6,186	7.300	3.311	0.828
09025-00	Hancock Creek	WA	033	0.77	0.45	0.45	F	0	5.220	2.599	1.169
09035-00	Clarence Creek	OR	057	0.53	0.95	0.53	F	3,120	0.550	0.258	0.138
09044-01	Bigg's Creek	WA	011	1.00	0.95	0.95	F	0	0.015	0.006	0.005
09060-01	North Boulder Creek	OR	005	1.00	0.10	0.10	F	0	3.100	1.747	0.175
09067-01	Warm Springs Creek	OR	019	0.87	0.20	0.20	F	0	3.000	1.374	0.275
09103-02	Cherry Creek	OR	003	1.00	0.85	0.85	F	1,647	0.015	0.006	0.005
09121A00	Nampa 1	ID	027	0.98	0.25	0.25	G	0	4.000	1.204	0.301
09121B00	Nampa 2	ID	027	0.98	0.25	0.25	G	0	4.000	1.204	0.301
09134-00	Dry Creek	ID	023	1.00	1.00	0.25	S	0	3.600	2.021	0.505
09247-01	Pratt Creek	ID	059	1.00	0.82	0.82	F	8,126	0.305	0.183	0.150
09336-00	Eagle Creek	WA	047	1.00	0.20	0.20	F	0	0.350	0.137	0.027

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
09364-00	Painted Rocks Dam	MT	081	0.99	0.45	0.45	J	0	5.000	3.500	1.575
09377-02	Big Quilcene	WA	031	0.70	0.25	0.25	G	1,173	1.000	5.708	1.427
09424-04	Cascade Creek	ID	021	0.77	0.95	0.77	F	2,286	0.900	0.405	0.313
09491-00	Fall Creek	OR	039	0.70	0.45	0.45	M	0	1.400	0.719	0.324
09543A00	Rim View Trout Company, Inc.	ID	047	1.00	0.65	0.65	S	9,911	0.215	0.205	0.133
09543B00	Rim View Trout Company, Inc.	ID	047	1.00	0.65	0.65	S	6,861	0.333	0.317	0.206
09587-00	Patterson Creek Associates	ID	059	0.74	0.20	0.20	F	4,448	3.000	1.712	0.342
09633-01	Hawkins Willow Creek	ID	019	0.75	0.20	0.20	F	6,647	0.693	0.428	0.086
09643-00	Tony Creek	MT	089	0.96	0.55	0.55	D	0	0.100	0.040	0.022
09656-02	Marble Creek	ID	079	0.65	0.95	0.65	F	0	3.200	1.142	0.742
09693-00	Challis Canal	ID	037	1.00	0.30	0.30	P	2,871	1.600	1.313	0.394
09867-00	Newman Ranch	ID	059	0.73	0.60	0.60	F	20,859	0.140	0.086	0.052
09883-02	Black Canyon	WA	033	1.00	0.45	0.45	F	0	2.500	13.744	6.185
09885-03	Falls River	ID	043	1.00	0.95	0.95	P	1,307	7.500	5.274	5.010
09890A02	Upper Mesa Falls	ID	043	0.74	0.10	0.10	F	1,763	8.000	7.203	0.720
09907-00	Sunshine	ID	059	1.00	1.00	0.10	S	5,503	0.110	0.065	0.006
09940-00	Pines Hydro	ID	037	1.00	0.20	0.20	F	11,200	0.900	0.628	0.126
09975-00	Howard Hanson Dam	WA	033	0.68	0.50	0.50	G	0	24.500	12.250	6.125
09986-00	Elk Creek Lake	OR	029	0.71	0.45	0.45	M	0	7.000	4.900	2.205
09998-00	St Anthony Canal	ID	043	1.00	0.20	0.20	P	0	0.800	0.628	0.126
10002-00	Lake Isabel	WA	061	1.00	0.40	0.40	I	0	5.000	2.500	1.000
10019-01	Scoggins Water Power	OR	067	0.69	0.20	0.20	M	0	1.500	0.474	0.095
10027-00	Broughton	WA	059	0.57	0.55	0.55	D	0	4.500	4.326	2.380
10039-00	Riverdale Hydro	ID	041	0.74	0.20	0.20	F	0	5.200	2.215	0.443
10040-01	Dry Creek	ID	041	0.74	0.20	0.20	F	17,776	14.000	2.340	0.468
10069-00	Upper Deer Creek	OR	033	0.55	0.95	0.55	F	0	3.350	1.296	0.713
10100-00	Irene Creek	WA	057	1.00	0.45	0.45	F	0	3.680	1.839	0.828
10101-00	Black Creek	WA	061	1.00	0.45	0.45	F	0	1.230	0.629	0.283
10106-00	South Creek	ID	023	1.00	0.45	0.45	F	0	0.450	0.198	0.089
10115-01	Bull Run Creek	ID	035	0.98	0.20	0.20	O	0	3.950	2.765	0.553
10145-00	Lowe Creek	WA	033	1.00	0.45	0.45	F	0	1.720	0.864	0.389
10146-00	San Juan Creek	WA	061	1.00	0.45	0.45	F	0	2.240	0.896	0.403
10148-00	Bear Creek	WA	061	1.00	0.45	0.45	F	0	2.700	1.080	0.486
10151-00	Howard Creek	WA	061	1.00	0.45	0.45	F	0	3.500	1.727	0.777
10152-00	Excelsior Creek	WA	061	1.00	0.45	0.45	F	0	1.700	0.816	0.367
10164-00	Hazelton A	ID	053	1.00	0.95	0.95	P	0	8.940	2.854	2.711
10178-00	Deadwood Dam	ID	085	0.87	0.20	0.20	J	0	2.600	2.055	0.411
10180-00	Deep Creek	ID	003	0.98	0.45	0.45	F	0	1.646	0.982	0.442
10184-00	Pressentin Creek	WA	057	1.00	0.45	0.45	F	0	3.160	1.264	0.569
10186-00	Sloan Creek	WA	061	1.00	0.45	0.45	F	1,333	3.620	2.174	0.978
10187-00	Salmon Creek	WA	061	1.00	0.45	0.45	F	1,712	2.880	1.438	0.647

Table 8-B-1
Potentially Developable Hydropower Sites[a]

FERC No.	Project Name	Location ST	Location CO[b]	Development Probability River	Development Probability Regul.	Development Probability Final	Type Code[c]	Cost ($/kWa)[d]	Installed Capacity (MW)	Average Energy (MWa)	Probable Energy (MWa)
10189-00	Burn Creek	WA	033	1.00	0.45	0.45	F	1,357	3.440	1.751	0.788
10193-00	Crystal Creek	WA	061	1.00	0.45	0.45	F	1,457	2.880	1.467	0.660
10194-00	Helena Creek	WA	061	1.00	0.45	0.45	F	1,114	2.200	1.701	0.765
10197-00	Skykomish Tributaries	WA	061	1.00	0.45	0.45	F	0	4.408	2.626	1.182
10206-01	New Prospect	OR	029	0.82	0.20	0.20	I	2,176	16.000	11.073	2.215
10208-00	Enterprise Hydro	ID	043	1.00	0.65	0.65	P	0	1.200	0.600	0.390
10210-00	Harlan Creek	WA	033	1.00	0.40	0.40	I	0	2.330	1.164	0.466
10213-00	Boulder Creek 1	WA	061	1.00	0.45	0.45	F	0	1.362	0.680	0.306
10214-00	Evergreen Creek	WA	061	1.00	0.45	0.45	F	0	1.701	0.850	0.383
10215-00	Fourth of July Creek	WA	061	1.00	0.45	0.45	F	0	1.696	0.848	0.382
10216-00	Bullbucker Creek	WA	061	1.00	0.45	0.45	F	0	1.548	0.774	0.348
10217-00	Johnson Creek	WA	061	1.00	0.40	0.40	I	0	2.515	1.258	0.503
10222-00	Barometer Creek 2	WA	073	1.00	0.45	0.45	F	0	10.700	5.365	2.414
10236-00	Lower Cedar Creek	ID	037	1.00	0.40	0.40	C	0	2.660	1.330	0.532
10237-00	Low Head 1	WA	001	1.00	0.95	0.95	P	2,524	0.200	0.080	0.076
10238-00	Low Head 2	WA	001	1.00	0.95	0.95	P	2,524	0.200	0.080	0.076
10239-00	Low Head 3	WA	001	1.00	0.95	0.95	P	2,524	0.200	0.080	0.076
10256-00	Hood Street Reservoir	WA	053	1.00	1.00	0.95	U	0	0.800	0.548	0.521
10258-00	Sonny Boy Creek	WA	057	1.00	0.45	0.45	F	0	3.510	1.791	0.806
10266-00	Found Creek 2	WA	057	0.90	0.45	0.45	F	0	4.120	2.079	0.935
10272-00	Thunder Creek	WA	057	0.90	0.45	0.45	F	0	2.494	1.244	0.560
10273-00	Shannon Creek	WA	073	1.00	0.45	0.45	F	0	2.430	1.215	0.547
10274-00	Sibley Creek	WA	057	1.00	0.45	0.45	F	0	2.980	1.493	0.672
10277-00	Wells Creek	WA	073	1.00	0.20	0.20	F	0	6.514	3.257	0.651
10287A00	Grandy Creek Tributary 1	WA	057	1.00	0.45	0.45	F	0	2.524	1.261	0.568
10287B00	Grandy Creek Tributary 2	WA	057	1.00	0.45	0.45	F	0	0.680	0.548	0.247
10290-00	Sandy + Dillard Creek	WA	073	1.00	0.45	0.45	F	0	3.787	1.894	0.852
10299-00	Nooksack River Tributary	WA	073	1.00	0.45	0.45	F	0	5.467	2.734	1.230
10305-00	Hidden Creek	WA	073	1.00	0.45	0.45	F	0	4.805	2.402	1.081
10326-00	Hazelton B	ID	053	1.00	0.95	0.95	P	0	7.500	2.580	2.451
10328-00	Alma/Copper Creek	WA	057	1.00	0.45	0.45	F	0	10.478	5.239	2.357
10356E00	Middle Fork Snoqualmie River	WA	033	1.00	0.45	0.45	F	0	1.397	0.699	0.314
10356G00	Middle Fork Snoqualmie River	WA	033	1.00	0.45	0.45	F	0	2.072	1.037	0.466
10360-00	Upper S. Fork Snoqualmie River	WA	033	0.63	0.40	0.40	I	7,379	1.838	0.919	0.368
10371-00	Bear Creek Power	WA	057	0.97	0.50	0.50	G	1,988	2.000	1.370	0.685
10382C00	N. Fork Snoqualmie (Calligan)	WA	033	0.77	0.20	0.20	F	1,448	3.583	1.791	0.358
10382D00	N. Fork Snoqualmie (Hancock)	WA	033	0.77	0.20	0.20	F	2,848	4.328	2.164	0.433
10392-00	Falls Creek	WA	061	1.00	0.45	0.45	F	7,021	3.460	1.764	0.794
10396B00	North Fork Payette	ID	015	0.43	0.40	0.40	C	0	320.000	114.808	45.923
10398-00	Goblin Creek	WA	061	1.00	0.45	0.45	F	0	0.759	0.377	0.170
10416-00	Anderson Creek	WA	073	1.00	0.45	0.45	F	2,052	3.094	1.705	0.767

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10420-00	Tye River	WA	033	1.00	0.60	0.60	I	0	8.000	3.984	2.390
10421-00	Howard Creek	WA	057	0.90	0.40	0.40	C	1,213	4.230	2.115	0.846
10424-00	Anderson Creek	WA	073	1.00	0.20	0.20	F	3,558	3.500	1.370	0.274
10428-00	Ebey Hill	WA	061	1.00	1.00	0.20	M	4,051	0.100	0.070	0.014
10432-00	Lookout-Fossil Creek	WA	073	1.00	0.40	0.40	I	0	1.500	0.582	0.233
10433-00	Ririe	ID	019	0.96	0.20	0.20	G	2,365	3.400	2.283	0.457
10468-00	Dike	ID	005	0.80	0.85	0.80	F	0	1.700	0.850	0.677
10496-00	Big Creek	WA	033	1.00	0.45	0.45	F	2,675	1.183	0.591	0.266
10536-00	Enloe Dam	WA	047	0.70	0.50	0.50	G	0	4.500	3.425	1.712
10540-00	Harry Nelson	ID	087	0.79	0.35	0.35	L	1,401	4.500	2.333	0.817
10552-00	Mile-28 Water Power	ID	053	1.00	0.65	0.65	P	0	1.500	0.750	0.487
10558-00	McCoy Creek	WA	061	0.73	0.20	0.20	M	3,541	0.230	0.228	0.046
10568-00	Cispus River 3	WA	041	0.77	0.45	0.45	F	0	13.100	9.804	4.412
10574-00	Freeway Drop	ID	039	1.00	0.65	0.65	P	0	1.400	0.685	0.445
10607-00	Reeds Creek	ID	035	0.88	0.45	0.45	F	10,556	4.800	1.735	0.781
10610-00	Trout Creek	ID	029	0.95	0.60	0.60	D	5,466	0.640	0.274	0.164
10611-00	Whiskey Creek	ID	029	0.91	0.60	0.60	D	2,353	0.640	0.584	0.351
10625-00	Taneum Chute	WA	037	1.00	0.65	0.65	P	0	0.760	0.212	0.138
10671-00	Silver Creek	WA	041	0.81	0.10	0.10	F	0	6.000	4.566	0.457

a This table was compiled using the best information available to the Council at the time the draft plan was prepared. Hydropower site information changes over time and is being refined constantly. Therefore, the inclusion of a specific project on this list does not imply that there are no institutional constraints on the development of the project. In particular, it should be noted that possible constraints presented by the Oregon listings of the federal Wild and Scenic Rivers Act and the Oregon Scenic Waterway Act (ORS 390805 to 390925) may apply to certain projects included on this list.

b Federal General Data Standard county code (key follows).

c Type code key:

Status of Waterway Structure	Run-of River	Diversion	Run-of River Reservoir with Diversion	Storage Reservoir	Storage Reservior with Diversion	Canal	Conduit	Pumped Storage
Existing	A	D	G	J	M	P	S	V
Existing w/power	B	E	H	K	N	Q	T	W
Undeveloped	C	F	I	L	O	R	U	X

d Note that capital cost is in terms of dollars per average kilowatt energy production.

CHAPTER 9

ACCOUNTING FOR ENVIRONMENTAL EFFECTS IN RESOURCE PLANNING

Chapter 9
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The Council's Environmental Strategy

The Northwest Power Act identifies several distinctly different ways that environmental effects are to be considered by the Council, in developing its power plan, and by the administrator, when Bonneville acquires the capability or output of resources. Section 4(e)(2) of the Act requires the Council to give "due consideration" to the environment in developing its plan for the region. Section 4(e)(3)(C) requires the Council to include in the plan "a methodology for determining quantifiable environmental costs and benefits under section 3(4)." Section 3(4)(B) defines incremental system costs of a resource to include "such quantifiable environmental costs and benefits as the administrator determines, on the basis of a methodology developed by the Council as part of the plan...are directly attributable to such measure or resource."

Congress recognized that the Council's consideration of environmental effects would occur during the planning stage, before specific information related to siting is available. At that phase of planning, it is not possible to develop specific estimates of environmental effects. Consequently, the Council's consideration of environmental effects must be focused on general effects associated with various types of electricity resources. This required the Council to use considerable judgment in its deliberations on how environmental effects are factored into establishing priorities for resource acquisition.

To shape that judgment, the Council adopted the following strategy to help explore the environmental effects of resources and to decide how to incorporate them in the planning process.

1. The Council elected to continue to incorporate existing regulation in resource costs. The costs of meeting existing laws and regulations, such as provisions in the Clean Air Act, are reflected in the resource costs that are used throughout the power plan.

2. The Council elected to continue incorporating into resource decisions prior environmental judgments on resources. In prior deliberations, the Council moved to protect the environment in specific ways. For example, the Council incorporated indoor air quality provisions in its efforts to secure energy-efficient housing, it designated certain river stretches as protected from hydropower development, and it developed criteria that are to be met before Bonneville offers financial assistance for hydropower development. These costs and constraints are incorporated into the assessment of each resource and are discussed in their respective chapters.

3. The Council conducted sensitivity analyses to see what would happen if resources with less environmental impact were favored over the base-case portfolio analysis. This meant departing from strict cost-effectiveness based on internalized costs by switching the places of resources in the portfolio. These, as well as other sensitivity studies, were crucial in helping define the

consequences of possible actions. They are described more fully in the resource portfolio chapter (Volume II, Chapter 10).

4. In some circumstances, the Council went beyond current regulation to incorporate the best environmental control technology. This was the case with coal plants.

5. The Council developed descriptive information on emissions and other key impacts from resources, to the extent information is available. This chapter compiles the information that was collected on each resource. The information was used to help judge the relative environmental impact from each resource.

6. The Council expanded the conservation supply curves to see how much of this environmentally more benign resource was available, beyond the amount already identified as cost-effective. This resulted in about 1,100 to 1,200 average megawatts of promising resources. About 880 average megawatts of these resources are commercially available today, but did not fall below the cost-effectiveness threshold, while the remainder were considered emerging technologies. These are all described more fully in the conservation chapter (Volume II, Chapter 7). As a result of these efforts, the Action Plan identifies, and strongly supports, activities to initiate research, development and demonstration to bring these resources to fruition.

7. The Council elected to limit the amount of certain resources that would be available to the portfolio. Part of the reason for these limitations was to constrain risk due to fuel price uncertainties, but another significant reason was to reflect the uncertainty surrounding possible environmentally based regulation of fossil fuel combustion. It appears increasingly likely that some form of regulation or taxation of carbon dioxide and other "greenhouse" gases could occur. Therefore, it is only prudent to anticipate some limitations on the desirability of fossil-fuel combustion resources. Thus, the amount of coal in the portfolio was limited to 4,800 average megawatts, the amount of gas fired cogeneration was limited to 1,720 average megawatts, and the amount of natural gas used to firm hydropower was limited to 2,500 average megawatts, with no more than 1,000 average megawatts developed before the year 2000.

In implementing the strategy described above, the Council effectively weighed the costs and benefits of environmental mitigation and explored alternative actions for incorporating environmental considerations. None of these choices led to establishing an explicit dollar value for externalities. However, the actions did lead to an informed judgment about which resources are most appropriate to meet loads and which have the least impact on the environment. The final judgment was that conservation, in particular, and most renewable resources have fewer and less severe environmental impacts than either fossil-fuel-based generation or nuclear power and, therefore should be vigorously pursued before the development of fossil-fuel-based generation or nuclear. This is especially important given the large uncertainty introduced by potential regulation of emissions from fossil-fuel burning plants to control global warming. Action on conservation has effectively become the theme of the power plan, and this theme is reflected in the direction given in the recommended activities in the Action Plan, Volume II, Chapter 1, of the power plan. In addition, the Council decided to continue work on the enhancement of methodologies for quantifying and incorporating environmental costs. This is also featured in the Action Plan.

While the discussion above describes the strategy for environmental consideration during the planning process, at the time of resource acquisition, the administrator or other purchasers of the electricity will have much more information specific to the resource and its location. Using this more specific information, and a methodology for weighing quantifiable environmental costs and benefits such as that developed by the Council and appearing in Appendix 9-A of this chapter, the administrator or other purchaser can conduct specific estimates of environmental costs and benefits and weigh them accordingly. The Council's methodology for determining quantifiable environmental costs and benefits contains specific steps needed to quantify costs and benefits, but recognizes that within the specific steps, quantification of environmental effects becomes almost an art form. Details of the methodology are, as a result, quite general. The methodology recognizes that not all environmental effects can be adequately quantified in dollars. However, for those that can be so quantified, the methodology refers the analyst to an exhaustive set of tools for quantifying environmental costs and benefits. The tools and their description were assembled for the Council under contract during the development of the 1983 plan. These estimation methods represent the best thinking on various methods in use to quantify the effects of environmental costs and benefits. The Bonneville Power Administration has taken this methodology and applied it to various resources in an attempt to test the methodology. These have been some of the most extensive efforts in the nation to quantify the environmental costs of resources.

The remainder of this chapter reviews the experience of evaluating environmental costs in other regions of the country, and then looks at the various environmental effects of pollutants associated with various types of generating resources and conservation. This section first summarizes the type of impacts that major pollutants have on the environment. It then describes the major pollutants associated with various generating technologies. For example, carbon dioxide is emitted during fossil-fuel burning and therefore is released by both coal plants and gas-fired turbines. Finally, the section reviews the residual environmental effects[1] of each resource. Where applicable and where the information is available, physical quantities of pollutant releases are shown. Physical quantities shown are those released even though mitigation controls are installed and operating satisfactorily.

Review of Experience in Other Regions of the Country

Environmental effects of generating resources historically have been addressed either by establishing required mitigation (design requirements) or by establishing maximum allowable releases (performance standards). The regulations depended in

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1./ In this context, residual environmental effects are defined as the effects of pollutants released to the environment, assuming all pollution control equipment is in place and operating. Each plant is assumed to have incorporated all pollution control equipment required by the most stringent standards in each of the four Northwest states. The capital costs of pollution mitigation equipment are included in the costs estimated for each resource.

part on where the resources were to be developed and the ambient environmental conditions.[2]

Because full control of environmental impacts may be extremely costly or not possible, the requirements fall short of total mitigation of the adverse environmental effects associated with resource exploration, development, operation, waste disposal, and retirement. Thus, there are residual effects on the environment that remain after regulatory requirements have been met. Before the Council was formed in 1981, the residual effects were given a lot of attention by the academic community, but were often ignored by utility planners when they made resource decisions. Because the costs of environmental damage caused by power plants were not being "paid" by utilities, the costs and rates of the utilities often did not account for the damages, and the utilities had no economic incentive to mitigate pollutant levels. Environmental damages that are not paid for by the polluter represent the classic economic problem of externalities, actions that impose costs on society, but for which, in this instance, the polluter is not required to pay.

The typical response to fix externalities is government regulation, to either control the externalities or to establish a market for the right to impose the external costs. Both of these methods internalize the costs imposed by forcing the agent of the externality to either mitigate or pay[3] for the external costs imposed. Typically, governments at the federal and state level have chosen regulation. The most important of the regulations is the Clean Air Act and the rules established by the Environmental Protection Agency pursuant to the Clean Air Act. Recently, several states have established markets in "rights to pollute" as an alternative approach to limiting pollutants. In this concept, there is usually an overall air-quality level established for an airshed, and within the allowed level, polluters are allowed to bid for the right to pollute. If the market works as it should, higher-valued products will be able to bid away rights from lower-valued products. The question of the overall level of pollutants to be allowed is still a major environmental and political policy call.

The Northwest Power Act directed the Council to give due consideration to environmental quality. In addition, the Council is the first planning body that actually included an explicit premium for conservation in its planning. As mentioned earlier, in general, the Council does not include a dollar value for externalities during its planning stage, but instead it considers the relative environmental degradation from each of its planned resources subjectively.

2./ Requirements are established based on whether a resource is developed in an area that has attained a certain level of environmental acceptability or not. These areas, for obvious reasons, are referred to as attainment and non-attainment areas. Resources developed in attainment areas have to use the best available control technologies to reduce the amount of undesirable emissions. Resources developed in non-attainment areas must obtain a permit, one requirement of which is emission control to a level that does not violate performance standards (for releases) or ambient air-quality requirements. In addition, offsets of pollutants from other sources may be required to achieve a net reduction in emissions.

3./ In fact, payment is not tied to damages imposed. It is determined by willingness to pay for the right to pollute.

However, in the five-year review of conservation, submitted to the U.S. Congress in 1987 pursuant to Section 4(k) of the Northwest Power Act, the Council recommended to the administrator of Bonneville that he maintain the 10-percent cost advantage for conservation, in part, because conservation is benign environmentally compared to most other resources.

The Council also has made environmental decisions based on the preponderance of evidence and on its own initiative. These decisions were made without specific dollar estimates of the differential environmental damages of alternative resources, but with considerable supporting information. For example, the Council's decision to protect certain important stream reaches was aided by a lengthy and detailed study of the effects of hydropower development on fish and wildlife; however, an assessment of the dollar value of hydropower-related damages was not made, nor was it needed. In the future, the Council can continue to grant a pre-approved environmental benefit to one or more resources, or to make environmental decisions based on the preponderance of evidence, whether or not valid dollar estimates of the relative damages can be made.

Other states followed the Council's decision to maintain an environmental benefit for conservation. Wisconsin, citing the Council's actions, adopted a 15-percent credit for conservation resources because of their environmental benefits. New England is considering going well beyond the 15-percent benefit given conservation in Wisconsin. New York has recently adopted a scoring system to evaluate the environmental costs of all resources. In this system, conservation scores well, as do some renewables. The fact that all of these efforts have attached a benefit to conservation relative to all other resources, is an indication of how difficult it is to treat all resources on a comparative basis. Conservation clearly is more environmentally benign than most generating resources, but the residual effects of all generating resources also vary. And, the relative effects of these resources are very hard to determine. As a result, the difficult task of determining the comparative effects, in a quantitative assessment, has not been completed satisfactorily in other areas of the country. This chapter attempts to make that comparative assessment.

Many utility representatives have expressed concern over the assessment of environmental effects, because if the damages from generating resources are determined to be high, utilities' avoided costs will be raised. Higher avoided costs could force acquisition of higher-cost resources because of the Public Utility Regulatory Policies Act (PURPA) and inclusion of higher-cost conservation in utility acquisition plans. Some utilities in New England have accepted estimates of environmental costs that were higher than anticipated. If high external costs push up the avoided cost and require utilities to do more conservation, it is acceptable as long as they get adequate returns on conservation expenditures. In this instance, rates will increase more than they would otherwise. Some utilities, perhaps those whose rates have been stable for some time, can deal with rate increases more easily than others.

Review of Environmental Pollutants and Their Major Effects on the Environment

The purpose of this section is to lay out in some detail the major environmental effects caused by actions related to both generation and conservation options contained in this plan. In any discussion of environmental effects, it is important to maintain a balanced perspective, one that does not distort the relative effects of each resource. If taken in isolation, discussion of the effects of a particular pollutant or action associated with resource development can be misleading. Discussion tends to focus on what we know best, when what we do not know may be of greater environmental harm. Each resource has some negative environmental effects. Because very few, if any, resources are environmentally benign, the effects of each of the resources have to be considered relative to one another. The existing literature is not well balanced in its treatment of each resource, nor are the environmental effects of resource development compared against other resources or against the risks that humans face every day. The environmental effects of any resource development and operation looked at alone may appear to be great, but the risks imposed on humans and the environment may be less than activities we choose to do every day. It is critical, to the extent possible, that we keep these issues in perspective.

To the extent practicable, each of the major environmental pollutants or other disruptions to the environment are physically quantified, and the damages or benefits associated with each are described. This enabled the Council to consider the order of resource acquisition based on systemwide criteria, such as costs, operating profiles and so forth, along with the anticipated environmental effects associated with each resource. As discussed above, through this process, the Council decided to pursue aggressively the more environmentally benign resources, such as conservation.

The first step in this overview is to identify all of the known and hypothesized effects of major pollutants or other actions related to generating electricity. This will be done without regard for the source of the pollutant. The effect of sulfur dioxides, for example, will be discussed regardless of its source. Later, in the discussion of each resource, the physical quantity of sulfur dioxides per megawatt-year associated with each generating technology will be presented. This will allow consideration first of the effect (cost and benefits) of the pollutant, followed by a comparison of each resource based on the physical amount of the pollutant emitted.

Table 9-1 contains a list of environmental pollutants from actions related to generating power in the left hand column and the element of the environment that is affected along the top of each column. An "x" in a cell of the table indicates where there are known environmental effects. Table 9-2 contains the same list of pollutants in the left hand column of the table and three review criteria along the top of the columns. The three criteria are: 1) the National Environmental Policy Act; 2) "criteria pollutants" regulated by the Clean Air Act; and 3) applicability to more than one resource. Entries in Table 9-2 can be thought of as a measure of the perceived importance of the pollutant historically. Entries in the first and second columns mean that the pollutants are addressed by the Environmental Protection Agency in one way or another and are also addressed in the federal Clean Air Act. While it can be argued that all of these effects are important, to consider all of the effects equally will obscure those that are more important. Tables 9-1 and 9-2 taken together can help to pare down the exhaustive list to concentrate on those major pollutants or actions that are expected to have the greatest effect on the environment.

Although none of the pollutants can be considered unimportant, a review of Tables 9-1 and 9-2 shows that pollutants emitted during plant operation have been given more attention by the regulatory agencies than pollutants emitted at other times. This is due in part to the vast amounts that can be emitted, in part because of the damaging properties of the pollutants, and in part because airborne emissions from plants can affect the environment, not only at and around the plant site, but also as far away as thousands of miles. In particular, the following airborne emissions appear to be the most onerous and deserving of scrutiny: 1) particulates; 2) sulfur dioxide (SO_2); 3) nitrogen oxides (NO_x); 4) carbon monoxide (CO); 5) hydrocarbons[4] (HC); and 6) carbon dioxide (CO_2). Carbon dioxide is not one of the "criteria pollutants" designated by the Environmental Protection Agency, but it is the major "greenhouse gas," which could cause the planet to undergo dramatic climate changes. Thus, it has been included in the list of emissions of major concern.

The task of the rest of this paper is to describe the effects indicated in Table 9-1 for each resource and to distill all of the information down to a usable summary of environmental impacts. The distillation should be adequate for power planning, because the specific site of the plant is not known at this time. At the time of proposed acquisition, additional specific analyses will have to be undertaken before any resource can be considered environmentally acceptable.

4./ Hydrocarbons are not discussed further in this document, because they are easy to control and are well controlled by existing regulation.

Table 9-1
Second-Order Impact Matrix

	Physical Environment			Biological Environment				Socioeconomic Environment	
				Fauna		Flora			
	Visibility	Material Damage	Human Health	Population Changes	Habitat Change	Vegetation Damage	Crop Losses	"Boom Town" (Public Services)	Recreation
Air									
Particulates	X		X						X
Sulfur Dioxide	X	X	X	X	X	X	X		X
Nitrogen Oxides		X	X	X	X	X	X		X
Carbon Monoxide			X	X	X	X	X		X
Hydrocarbons	X		X		X				
Lead			X	X					
Trace Elements			X	X	X				
Aldehydes									
Dust	X	X	X		X				X
Other: Methane									
Hydrogen Sulfide		X	X	X	X	X	X		X
Radioactive Gas (Tritium, Iodine, Noble Gases)		X	X	X					X
Ammonia		X	X	X					
Argon									
Carbon Dioxide[a]			X	X	X	X	X		X
Water									
Biological Oxygen Demand				X					
Chemical Oxygen Demand				X					
Suspended Solids			X	X	X	X	X		
Dissolved Solids			X	X	X	X	X		X
Toxic Substances/			X	X	X	X	X		X
Trace Elements			X	X	X	X	X		X
Organics				X	X	X	X		X
Consumption/Requirements				X	X	X	X		X
Other: Carbonates									
Ammonia			X						
Chlorine			X	X	X	X	X		

Table 9-1 (cont.)
Second-Order Impact Matrix

	Physical Environment			Biological Environment				Socioeconomic Environment	
				Fauna		Flora			
	Visibility	Material Damage	Human Health	Population Changes	Habitat Change	Vegetation Damage	Crop Losses	"Boom Town" (Public Services)	Recreation
Land									
Use/Requirements					X	X	?	X	X
Solid Waste			X	?	?	?	?		
Other									
Noise		X		X				X	
Radioactive Emissions			X	X	X	X	X		X
Community Infrastructure									

a These impacts assume that increased carbon dioxide will cause global warming.

C:TF/V21990.AA9 Tables 9-1 and 9-2

Table 9-2
Applicability of Selection Criteria to First-Order Impacts

	Criteria		
	NEPA Requirements	Criteria Pollutant	Applicability to Multiple Resource Options
Air			
Particulates	X	X	X
Sulfur Dioxide	X	X	X
Nitrogen Oxides	X	X	X
Carbon Monoxide	X	X	X
Hydrocarbons	X	X	X
Lead	X		X
Trace Elements	X		
Aldehydes	X		
Dust	X		
Other: Methane	X		
Hydrogen Sulfide	X		
Radioactive Gas (Tritium, Iodine, Noble Gases)	X		
Ammonia	X		
Argon	X		
Hydrogen	X		
Carbon Dioxide	X		
Water			
Biological Oxygen Demand	X		X
Chemical Oxygen Demand	X		X
Suspended Solids	X	Water	X
Dissolved Solids	X	quality	X
Toxic Substances/		criteria	
Trace Elements	X		X
Organics	X		X
Consumption/Requirements	X		X
Other: Carbonates	X		X
Ammonia	X		X
Chlorine	X		
Phosphates			
Land			
Use/Requirements	X		X
Solid Waste	X		X
Other			
Noise			X
Radioactive Emissions	X		
Community Infrastructure	X		X

C:TF/V21990.AA9 Tables 9-1 and 9-2

Description of Major Pollutants Associated with Multiple Plant Types

This section describes the major airborne effluents released from power plants and appropriate mitigation technologies for each.[5] Tables 9-1 and 9-2 show a number of important pollutants that are associated with most of the fossil fuel-fired plants. They are: 1) particulates, 2) sulfur dioxide, 3) oxides of nitrogen, 4) carbon monoxide, 5) carbon dioxide and 6) methane. These effluents may be released from gas, coal, biomass and other combustion technologies. They are being addressed here as a group, so that the information will not have to be repeated under the discussion of each separate resource, which follows. Effluents and damages unique to a particular resource will be discussed below for each resource.

Particulates

All small particles and liquid droplets in the air are referred to as the Total Suspended Particles (TSP). That subset of particles small enough to be inhaled and to lodge in the lungs is referred to as Respirable Suspended Particulates (RSP). These smaller particles are often toxic, because they can carry harmful pollutants that can damage the lining of the lungs. Most of the respirable suspended particles are formed by combustion of fossil fuels in automobiles, industrial processes and in power plants.

Particulates also affect visibility, because they are part of the smog and haze problems that are epidemic in large cities. Loss of visibility has been shown to be costly to the public in a number of economic studies.

Mitigation

With coal combustion, the composition of the particulates and their emission levels are a function of the plant's firing configurations, boiler operation and coal properties. The primary kinds of control devices include electrostatic precipitators, fabric filters (baghouses) and scrubbers. Some control even results from ash settling in boiler/air heater/economizer dust hoppers, large breeches and chimney bases.

Electrostatic precipitators are the most common high-efficiency control device used on pulverized coal. They are typically more than 99-percent efficient at removing the particulates in the flue gas. The presence of sulfur increases the efficiency of the electrostatic precipitators. When low sulfur coal is being used and

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5./ Much of the material that follows is taken from reports produced for the Council by NERO, Inc. under contract in 1982; from a draft report prepared for Bonneville by Battelle Northwest earlier this year; from the Council's 1986 Power Plan; and work done for the Council by Battelle as the Council developed its first power plan.

the precipitator is located after air preheaters (i.e., cold side precipitators) their efficiency is significantly reduced.

Baghouses have a similar efficiency and are being used increasingly in utility and industrial applications. An advantage of this technology is that it is unaffected by high fly ash resistivities associated with low-sulfur coals, which affects the operation of electrostatic precipitators.

Scrubbers also are used to control particulates, although their primary use is to control sulfur oxides. A drawback with scrubbers is the large amount of energy they require if they are to achieve a control efficiency comparable to precipitators or baghouses.

For fuel oil combustion, particulate emissions depend most on the grade of fuel fired. Lighter distillate oils result in significantly fewer particulates than the heavier residual oils. And the heavier residual oils produce more than the lighter residuals. In boilers firing residual (No. 6) fuel oil, particulate emissions are a function of the sulfur content of the oil. These emissions can be reduced considerably when low-sulfur residual oil is fired.

On large, oil-fired boilers, mechanical collectors often are used to control particulates. Electrostatic precipitators also are commonly used. Older, usually smaller precipitators remove generally 40 to 60 percent of the particulate matter. Today, new or rebuilt precipitators have collection efficiencies of up to 90 percent. Scrubbing systems can also remove 50 to 60 percent of the particulates.

Boiler load also can affect the emissions of particulates in units firing residual fuel oil. At low-load conditions, particulate emissions may be lowered 30 to 40 percent from utility boilers and by as much as 60 percent from small industrial and commercial units. However, this does not appear to be true when firing lighter grades of oil.

Particulates are the major emission of concern from wood-fired boilers, in which furnace design and operating conditions are particularly important in controlling particulates. For example, because of the high moisture content that can be present in wood wastes, a larger than usual area of refractory surface is often necessary to dry the fuel before combustion. In addition, sufficient secondary air must be supplied over the fuel to burn the volatiles. Fly ash reinjection has a considerable effect on particulate emissions and is a technique commonly used in many larger boilers to improve fuel efficiency.

In addition, wood-fired boiler emissions are influenced by boiler size and type, design features, age, load factors, wood species and operating procedures. And when wood is co-fired with other fuels, as it often is, the effect of these factors on emissions is difficult to quantify.

Municipal solid waste plants use a wide variety of control technologies to control particulate emission rates. Currently the most widely used are electrostatic precipitators, fabric filters, wet scrubbers and dry scrubbers.

Sulfur Dioxide

Much of the sulfur in coal and fuel oil is converted to sulfur dioxide during combustion. The sulfur dioxide emitted into the atmosphere either settles out locally or is slowly transported over large distances and converted to sulfuric acid or sulfates. The potential impacts from these emissions include human health effects, crop and forest damage, acid rain, metal corrosion and visibility degradation.

Health effects in humans include shortness of breath, coughs, viral respiratory infections, and allergic reactions when inhaled as respirable particles. Long-term exposure to sulfur dioxide can cause chronic bronchitis and exacerbate asthma. Other effects include changes in blood chemistry, enzyme levels, lung capacity and pulmonary resistance. Sulfur dioxide is also believed to have carcinogenic effects. These impacts occur when sulfur dioxide levels are high, generally above the national ambient air quality standards.

Acid rain results from the combination of sulfates and oxides of nitrogen.[6] Acid rain is known to acidify lakes, harm certain key flora and fauna, corrode buildings, bridges, and other infrastructure, and is a major culprit in impairing visibility. It is also believed to be a carcinogen.

Mitigation

One way to reduce sulfur dioxide from coal combustion is to burn lower-sulfur coals, since sulfur oxide emissions are proportional to the sulfur content of the coal. Most commercially available western coals have a low sulfur content.

Flue gas desulfurization techniques are used for further reduction of sulfur oxides formed during combustion. Wet lime scrubbing or limestone scrubbing are the most common methods used and can remove up to 95 percent[7] of the sulfur dioxide from the flue gases. A slurry of lime or limestone absorbs the sulfur dioxide, and a waste sludge of calcium sulfate (in the case of lime scrubbing) or sulfate and limestone (in the case of limestone scrubbing) is formed.[8]

6./ Acidity is measured in terms of "pH" or (p)otential of (H)ydrogen. The scale runs from 0 to 14, with 7 being considered neutral, above 7, alkaline, and below 7, acidic. The pH scale is logarithmic; for example, the acidity of a pH 5 liquid is 10 times that of a liquid of pH 6. Acid rain is defined as rain with a ph of less than 5.6. The effect of acid rain depends on where it falls. For example, if it falls on an area that is already acidic, it could do more damage than if it falls on an area that is naturally low in acidity.

7./ The higher the removal rate, the higher the capital and operating costs. Scrubbing to 95 percent will require more capital and higher operating costs. With a given scrubber, operating costs are related directly to the degree of scrubbing done.

8./ Magnesium oxide, double alkali, sodium bicarbonate, ammonia or alkali fly ash can also be used as fluids to absorb sulfur dioxide.

After being treated to prevent sulfur from leaching to the groundwater, the waste sludge is buried in landfills. Some is recycled for its gypsum content.

Advanced generating plants offer alternate ways to control sulfur dioxide emissions. For example, fluidized-bed combustion coal plants prevent the creation of sulfur dioxide by injecting lime in the fluidized bed before sulfur dioxide is produced. This technique appears to be all that is needed with low-sulfur coal, but fluidized-bed combustion would need additional mitigation if high-sulfur coal is used. Gasification plants incorporate sulfur removal equipment in the product gas clean-up section to remove sulfur from the gas prior to combustion.

The sulfur emissions from fuel oil combustion depend almost entirely on the sulfur content of the fuel and are not affected by boiler size, burner design or grade of fuel being fired. Scrubbing systems have been installed on oil-fired boilers to control sulfur oxides. These can be 90 to 95 percent effective.

Municipal solid waste systems also widely use scrubbing systems.

Oxides of Nitrogen

Oxides of nitrogen include nitrogen dioxide (NO_2) and nitric oxide (NO). Both of these can form nitrosamines--highly potent carcinogens in aqueous solution.

When exposed to ozone, nitric oxide reacts to form nitrogen dioxide. Nitric oxide is a gas that can irritate membranes and can cause coughs and headaches. Further, nitrogen dioxide can react with moisture to form nitric acid ("acid rain"), which is known to damage buildings, bridges and other infrastructure, as well as fish, vegetation, soil and surface water.

Mitigation

One technique to minimize oxides of nitrogen is to switch to a coal or fuel oil with a lower nitrogen content. However, this is limited by the ability of a given boiler configuration to fire a different type of fuel and by the cost and availability of substitute fuels.

In coal units, the formation of oxides of nitrogen can be reduced by modifying the way the fuel is burned. One technique called "low excess air firing" limits the amount of combustion air (and thus nitrogen) available, reducing the formation of oxides of nitrogen. This is the most widely used technique, because it can be practiced in both old and new units and in all sizes of boilers. It is easy to implement and has the added advantage of increasing fuel-use efficiency. Low excess-air firing is generally effective only above 20 percent excess air for pulverized coal units. Below these levels, the nitrogen oxides reduction from the decreased availability of oxygen is offset by the increasing nitrogen oxide levels due to the increased flame temperature.

Staged combustion requires two burn cycles. The first cycle uses a minimum amount of oxygen, and the second cycle increases the oxygen level to yield a more complete burn. Staged combustion is another technique that limits the amount of nitrogen available in combustion by separating or stratifying the air/fuel mixture in the boiler. In fluidized-bed plants, the formation of oxides is slowed, because the combustion temperature is lower than for conventional furnaces (nitrogen oxide levels increase as a function of the combustion temperatures).

Other nitrogen oxide reduction techniques include flue-gas recirculation, load reduction, and steam or water injection. However, these techniques are not very effective for use on coal-fired equipment because of the nitrogen content of the fuel. Ammonia injection is another technique that can be used, but it is costly.

The reduction of nitrogen oxides from any of these techniques or combinations varies considerably with boiler type, coal properties and existing operating practices. Typical reductions range from 10 to 60 percent of the nitrogen oxides released from unmitigated coal plants.

Finally, the problem of nitrogen oxides is avoided entirely in medium Btu gasification plants, which use an oxygen feed so that no nitrogen is introduced to the combustion process through the fuel[9] or the combustion air.

Similar combustion modifications are used for fuel oil, natural gas and municipal solid waste plants. Limited excess air firing, flue-gas recirculation and staged combustion reduce nitrogen oxide emissions in large fuel oil facilities by 5 to 60 percent. Nitrogen oxide emissions with fuel oil can also be reduced by 0.5 to 1 percent for each percentage reduction in load from full load operation.

For natural gas plants, staged combustion can reduce emissions by 5 to 50 percent; low excess-air firing can reduce nitrogen oxide emissions 5 to 35 percent, and flue gas recirculation by 4 to 85 percent, depending on the amount of gas recirculated. Flue gas recirculation is best suited for new boilers, because retrofit applications would require extensive burner modifications. Low nitrogen oxide burners (20 to 50 percent reduction) and ammonia injection (40 to 70 percent reduction) also offer nitrogen oxide emission reductions. Combinations of these modifications also may be used to reduce emissions further.

Selected catalytic reduction can be used to reduce nitrogen oxide emissions by about 80 percent. This technique has not been used until recently, probably because it is expensive.

Carbon Monoxide

Carbon monoxide is a colorless, odorless gas. It interferes with the body's ability to deliver oxygen throughout the body. Moderate levels of oxygen deficiencies have caused vision and brain dysfunction. Headaches, nausea, irregular heart beat, weakness and confusion also can be caused by exposure to high levels of carbon monoxide. At the extreme, exposure to high levels of carbon monoxide can cause death. Fetuses whose mothers have been exposed to carbon monoxide have experienced decreased growth and mental development.

9./ The nitrogen is removed from the coal in the gasification plant.

Mitigation

Carbon monoxide is generally emitted in quite small amounts from coal plants. However, during start-ups, temporary upsets or other conditions preventing complete combustion, these emissions may increase dramatically. Measures used for nitrogen oxide control can increase carbon monoxide emissions, so such measures are applied only to the point at which carbon monoxide in the flue gas reaches a maximum of about 200 parts per million. Other than maintaining proper combustion conditions in coal and fuel oil units, control measures to limit carbon monoxide are not typically applied.

Carbon Dioxide

The combustion of any fossil fuel or the gasification of coal produces carbon dioxide. Carbon dioxide is the main component of "greenhouse gases," the gases popularly believed to cause global warming. Carbon dioxide and the other greenhouse gasses let the sun's radiation through, but trap in the heat, keeping it from escaping the earth's surface. The greenhouse effect of the atmosphere is not anything new. The earth would be too cold for human survival without this characteristic of the atmosphere. What is new is the rapid change in the concentrations of greenhouse gasses. Climatologists have argued that the increasing concentrations of greenhouse gasses are causing the earth's temperature to increase, with potentially disastrous results. The feared results include rising sea levels inundating vast areas of the world, climate changes too rapid too allow plants and animals time to adjust to the new realities, and dramatic changes in local climates around the world.[10] One of the key elements driving these fears is the expected doubling of the world's population over the next 40 to 50 years. The doubling would take the earth's population to 10 billion people. In 1940, the earth's population was 2 billion people.

Mitigation

Variations in carbon dioxide emissions from one coal-based technology to another depend almost entirely on the overall efficiency of the process.

To date, there is no good way to mitigate the release of carbon dioxide from the combustion of fossil fuels. Some studies have been conducted to determine the cost of recovering carbon dioxide from the flue gasses, but the costs would be prohibitive and, if required, would probably mean that other resource options, such as wind, solar, geothermal and other renewables would be more cost-effective than coal.

10./ Interested readers should review the papers presented during a major workshop held by the Council on the greenhouse effect and its result, global warming. The workshop included presentations to the Council by world experts on the subject of global warming. It was held in Olympia, Washington, on February 9, 1989. Call the Council's public involvement division for copies.

A technique used recently is to plant trees in numbers appropriate to absorb carbon dioxide from a given power plant. The number of trees would be selected based on the ability of the tree type and climate to absorb over their lives the amount of carbon dioxide expected to be released from the subject power plant. Urban tree planting, which has the added effect of lowering temperatures in urban spaces could achieve the same results with fewer trees.

Methane

In addition to carbon dioxide, methane is an important greenhouse gas. The greenhouse effect is described above under the discussion of carbon dioxide. Methane is produced from naturally occurring biological processes. It is also released to the atmosphere when natural gas is vented. While carbon dioxide is undoubtedly a key greenhouse gas, methane is also important, because it is about 21 times more effective, molecule-for-molecule, than carbon dioxide at trapping infrared radiation.

Mitigation

Leaks when natural gas is drilled, transported and used are the key source of methane related to power production. Mitigation is best accomplished by prevention of leaks through maintenance.

Review of Environmental Effects by Resource Type

The previous section contained a discussion of pollutants that are released by most fossil-fuel-burning generators. This section will review the remaining environmental pollutants from each specific resource being considered for inclusion in the Council's power plan.

Coal-fired Generation

The previous section discussed the effects of oxides of nitrogen, carbon monoxide, carbon dioxide, sulfur dioxide and particulates released from any resource, including coal-fired resources. This section on coal-fired resources discusses other effects of coal-fired generation on the environment. Environmental effects of coal-fired generation start with the mining of the coal and continue through transportation to the generating plant, combustion of the coal to produce electricity and in decommissioning the plant.

Mining, Transportation and Coal Handling

Exploration for coal can include drilling and blasting which risk contamination of groundwater. Strip-mining coal involves removing large amounts of soil and other materials overlaying the coal beds. Federal law and state laws in a number of states require reclamation of strip-mined lands and include procedures for refilling and regrading, water protection and revegetation, as well as prohibitions against mining sensitive lands, such as alluvial valley floors and prime farmland. However, there is some question whether these reclaimed lands can sustain long-term productivity or establish a diversity of species characteristic of native range.

Because coal beds often serve as aquifers, their removal by mining often disrupts groundwater and can dry up neighboring wells used for domestic or stock water uses. The resaturation of soils when mined pits are refilled can degrade water quality. The Council's data indicated that acid mine runoff can contaminate local surface and groundwater, and toxic materials exposed by mining can both contaminate nearby water sources and hamper later efforts to reclaim the land.

Air quality is affected at this stage by the release of dust particles. Because the dust particles are large, and therefore reasonably filtered by the respiratory system, health problems are not considered to be a major concern. However, the total amount released can be large, both in the mining process and in the transportation of the coal. A unit train (100 cars long) can lose about 140 tons in particulates on a 700-mile run for each trillion (10^{1}) Btu of fuel transported. At a heat rate of 10,000 Btu per kilowatt-hour, 114 megawatts of coal plant could run for one year on 10^{12} Btu of coal. Therefore, a train haul supporting a plant the size of Boardman (in eastern Oregon) would lose about 455 tons of coal dust per year, assuming a 700 mile haul.

Plant Construction

See discussion under nuclear, later in this chapter.

Combustion of Fuel to Produce Electricity

Coal is contaminated with heavy metals, radionuclides and rare elements. Coal also can contain small amounts of radioactive materials. These are released into the atmosphere in the coal combustion process. The types and amounts of these pollutants released from a typical plant burning western coal are displayed in Table 9-3.

Table 9-3
Releases of Heavy Metals from Coal-Fired Power Plant

	Thousand pounds per megawatt-year	Pounds per year per plant[a]
Arsenic	.0003	128
Beryllium	Unknown	Unknown
Cadmium	.00003	11.7
Manganese	.000002	.6
Lead	.00008	32.1
Selenium	.000005	2.0
Uranium	.0018	718
Zinc	.0007	286
Radium-226	.0035 Curies	1,400 Curies

a Typical 500-megawatt coal plant burning western coal.

Water quality can be affected when cooling water is returned to its source. The water is heated in the cooling process and may come in contact with and be contaminated by solids, oils, grease and metals. This discharge can affect the health of the ecosystem and change productivity of the body of water, especially if the body of water is small. These effects can be mitigated with the use of large, contained settling ponds next to the plant.[11] Water quality also can be affected if rainwater comes in contact with coal piles, sludge or other contaminated surfaces before entering the groundwater.

The use of water in a coal plant also can affect fish and wildlife habitat when the water is withdrawn.

Waste Disposal

A typical 500-megawatt plant produces about 176,000 tons of solid waste per year, or about 440 tons per megawatt year, or about 25 tons per hour of operation. The waste is generally not considered to be toxic, but it does require a significant amount of land--several thousand acres over the life of a typical plant. The waste is disposed of in landfills or ash ponds. Leachate from the landfills can pollute surface waters. Because of the existence of lead in some waste, some vegetation has a difficult time growing in the waste.

Natural Gas-fired and Oil-fired Generators

Combined-cycle combustion turbines and single-cycle combustion turbines are being considered for the resource portfolio. These resources appear to have the best overall set of characteristics to complement the existing power system, in

11./ For example, Boardman's pond is 1,400 acres.

particular the hydropower portion of the system. These resources are being considered as the best way of "firming" nonfirm hydropower. Natural gas is generally much cleaner environmentally than coal. Distillate fuel oil, which will be used when gas is not available, will produce more pollutants than natural gas, but less than if coal were being burned.

There remains some question related to how methane releases to the atmosphere, associated with natural gas exploration, recovery and transportation, contribute to greenhouse gases and the related potential effect on global warming.

Exploration, Extraction, Transportation and Fuel Handling

Use of combustion turbines fueled with natural gas or oil raises certain environmental concerns in connection with exploration, development and transportation of the fuel. Off-shore exploration and development of fossil fuels can interfere with commercial and recreational fishing and could cause aesthetic impacts on shoreline areas. In addition, there can be fish and wildlife impacts from spills and leaks of crude oil from off-shore operations. On-shore exploration and development can intrude on roadless areas and wildlife habitat and affect the aesthetics of natural areas. If imports are relied on, there also may be increased risk of oil spills from tanker accidents. Transportation by pipeline involves potential spills and can disrupt existing land uses and cause some aesthetic impacts.

Most of the potential effect is related to the transportation of oil. When oil is transported, there is always a possibility of a spill. Spill rates have been estimated to be about 2.5 barrels per 219,000 barrels of oil transported. This would translate into about .08 barrels of oil spilled per megawatt-year, for a typical plant. Other effects, whose physical amounts have not been quantified, include methane releases in the exploration, extraction and transportation of natural gas, contamination of land and seas due to end-uses of oil and gas, and the environmental effects associated with construction and operation of oil and gas pipelines.

Combustion of Fuel to Produce Electricity

Other than the the airborne pollutants discussed in the general section above, there is little additional combustion-related pollution associated with natural gas-fired and oil-fired generation.

Biomass

Biomass can be used to produce electricity alone or to produce both electricity and process steam. This section discusses the effects of using biomass to produce electricity. The biomass resources considered here include: 1) wood residues, and 2) refuse derived fuel from municipal solid waste. Refuse derived fuel is municipal solid waste from which undesirable elements have been removed. It is distinguished in this way from municipal solid waste burned without sorting. Technologies that burn municipal solid waste without any sorting are called "mass burn" units. They are discussed later in this chapter.

Wood Residues

Wood residues usually are composed of logging slash and residues from lumber mills and other wood processing facilities. They include sawdust, bark and other wood leftovers from the cutting of lumber and from the production of manufactured lumber products.

Fuel Handling

The environmental effects of moving wood residues to power plants are minimal. In any case, similar effects would result if the wood residue is moved for an alternative use or to dispose of it, if there is no market value.

Combustion of Fuel to Produce Electricity

Additional environmental effects from wood-fired generation, aside from the major air pollutants discussed above, are not significant.

Refuse-Derived Fuel

Refuse derived fuel comes from garbage that has been sorted to eliminate non-combustibles and other undesirable elements.

Fuel Handling

Because collecting the garbage and sorting it are the only handling operations, whether the garbage is used for fuel or not, the incremental effect of fuel handling is zero.

Combustion of Fuel to Produce Electricity

Production of electricity from refuse-derived fuel can cause air pollution. The major criteria pollutants have been discussed above. In addition to those pollutants, refuse-derived fuel plants can emit volatile organic matter, mercury, lead, fluorides, hydrogen chloride, tetrachlorinated dioxins, beryllium, polynuclear aromatic compounds and polychlorinated biphanyls (PCBs). These pollutants can be mitigated to acceptably low levels by exposing the exhaust gases to temperatures in the 1,800 to 2,000 degree Fahrenheit range for several seconds and by using baghouses and electrostatic precipitators. Residual pollutants remaining after environmental controls have been installed are not well known, because the contents in a stream of garbage are not very consistent.

Waste Handling

Waste produced from garbage burning to produce electricity is in the form of an ash, which is typically buried in a lined landfill. Recently, discussions have centered on the toxicity of the ash. Some knowledgeable people believe that the ash will soon be deemed to be a toxic substance by the Environmental Protection Agency. If this ash were determined to be toxic, the cost of waste handling and the corresponding cost of electricity from refuse-derived fuel would increase. If the ash were judged to be toxic, plant operators would probably be required to "concretize" the ash to make it less likely to leach out toxins into the groundwater.

Biomass: Cogeneration

Wood Residue

Resources are the same as those discussed under biomass.

Fuel Handling

Same as under biomass.

Combustion of Fuel to Produce Electricity

Same as under biomass per unit of fuel input. Because cogeneration is more efficient, the amount of pollution per unit of useful work is lower than for a biomass resource producing electricity only.

Refuse Derived Fuel

Same as for refuse-derived fuel producing electricity only.

Fuel Handling

Same as for refuse-derived fuel producing electricity only.

Combustion of Fuel to Produce Electricity

Same as for refuse-derived fuel producing electricity only. Because cogeneration is more efficient, each level of refuse-derived fuel burned in the process results in more useful work. Therefore, the amount of pollution per unit of useful work is lower when refuse-derived fuel is being burned in a cogeneration mode.

Nuclear

This section presents an overview of the principal potential impacts a nuclear power plant could have on the environment. A summary of the major effects is provided along with a description of mitigating measures. Many of the environmental impacts of nuclear generating plants are those common to other central station generating facilities. This discussion is general (i.e., not plant-specific) and focuses upon unique aspects of nuclear plants.

Uranium Mining and Fuel Processing

Uranium, the fuel source for nuclear generators, is extracted by surface or open pit mining. Exploration can involve drilling, blasting and road building that may contaminate groundwater and disrupt wildlife habitat. The Council's data indicated that many of the same water pollution, air pollution and reclamation problems are encountered in uranium mining as in coal mining; the scale of uranium mining is substantially smaller, however, for a given energy content in the fuel. Also, the radioactive nature of uranium ore poses potential health risks to miners and persons living near uranium mines. Uranium ore processing results in large amounts of tailings that contain radioactive waste materials. These tailings may raise human health concerns and must be disposed of properly to avoid contamination of water sources or transportation by the wind. In addition to mining effects, nuclear fuel for light-water reactors is enriched. Electrical energy is used for the fuel-enrichment cycle, which occurs in areas served by coal-burning utilities. Therefore, nuclear enrichment also causes a portion of the environmental effects of coal burning.

Plant Construction

Construction of a nuclear power plant is a major undertaking and, because of large plant sizes, can create more severe "boom and bust" social and environmental effects than other generating plants. However, the effects are similar for nuclear and large coal plants. Significant local socioeconomic impacts have already been experienced at Washington nuclear projects 1 and 3 (WNP-1 and WNP-3). WNP-1 is located, however, in a community with a long-term commitment to nuclear work. Mechanisms for adjusting to economic fluctuations due to construction, may be better developed there than elsewhere. Some central station power developments (including nuclear plants) require high-voltage transmission lines and their associated effects.

The primary atmospheric impacts resulting from the construction of a nuclear power plant are those common to large construction projects. They include an increase in atmospheric dust due to removal of existing groundcover during construction activities and a decrease in air quality due to pollutants related to automobile exhaust. Soil erosion can be a significant problem at a large construction site. Special soil management practices are typically required to minimize adverse land and vegetation impacts during construction. Where there are small streams, erosion of exposed soil must be controlled to control sediment load, and disturbance of vegetation along the stream's banks must be minimized.

Producing Electricity

The potential atmospheric effects of nuclear power plant operation occur as a result of heat and moisture released from the plant cooling system, cooling tower drift and release of airborne radioactive materials. With the exception of airborne radioactive effluents, these effects are common to large, thermal generating facilities (radioactive materials also are released from the operation of coal-fired power plants). Airborne radioactive effluents can be divided into several groups. The first are isotopes of the fission product noble gases krypton and xenon, as well as those of argon, which are not deposited on the ground and are not absorbed and accumulated within living organisms. Treatment of noble gas effluents generally consists of collection, holding-up to permit decay of shorter-lived isotopes, followed by release. Noble gas isotopes act primarily as a source of direct external radiation emanating from the effluent plume.

A second group of airborne radioactive effluents, the fission product radioiodines, as well as carbon 14 and tritium, also are gaseous, but these effluents tend to be deposited on the ground and/or inhaled during breathing. Because these are active elements that may be incorporated within the body, concentrations of iodine in the thyroid and of carbon 14 in bone are of particular significance. Currently, Iodine-131 is captured by filtration through charcoal beds. Carbon 14 and tritium are released.

The third group of airborne effluents is made up of particulates. These include fission products, such as cesium and barium, and activated corrosion products, such as cobalt and chromium. Particulates are controlled by filtration in high-efficiency particulate filters.

Permissible levels of radiation in unrestricted areas and release of radioactivity and effluents to unrestricted areas are specified in 10 Code of Federal Regulations, part 20, Standards for Protection Against Radiation. These regulations specify limits on levels of radiation and limits on concentrations of radionuclides in releases in the air and water. These regulations state that no members of the general public in unrestricted areas shall receive a radiation dose as a result of facility operation of more than 0.5 rem[12] in one calendar year or, if an individual were continuously present in an area, 2 millirem to the total body in any one hour or 100 millirem in any seven consecutive days. Experience with the design, construction and operation of nuclear reactors indicates that average annual releases of radioactive material and effluents typically will be small percentages of the limits specified in 10 Code of Federal Regulations, part 20 (Table 9-4).

Potential water-related effects of nuclear power plant operation include thermal discharges, release of waterborne chemical pollutants, water consumption and release of waterborne radioactive materials.

Because of potential thermal impacts to aquatic organisms residing in surface waters, either through raising of the temperature of the receiving waters or by

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12./ A rem is the dosage of any ionizing radiation that will cause the same amount of biological injury to human tissue as one roentgen of high-penetration x-rays. A millirem is one thousandths of a rem.

thermal shock accompanying changes in plant operation, most contemporary power plants use the atmosphere as a heat sink. This is accomplished by use of closed-cycle cooling involving the use of cooling ponds, lakes, canals, or natural or mechanical draft cooling towers for heat exchange with the atmosphere. The existing Washington nuclear project 2 and Trojan nuclear plant, plus all Northwest nuclear plants currently planned or under construction use some form of cooling tower for waste heat discharge.

Table 9-4
Representative Releases of Airborne Radioisotopes from Commercial Nuclear Power Plants

Isotope	Boiling Water Reactors (curies/year)	Pressurized Water Reactors (curies/year)
Noble Gases	32,774.0	10,179.0
Iodine-131,133	2.9	0.015
Carbon-14	9.5	8.0
Tritium (H-3)	78.0	760.0
Particulates	0.26	0.06
Maximum individual Total Body Dose from Noble Gases	0.31 millirem/yr.	0.14 millirem/yr.
Maximum Individual Organ Dose from Iodine and Particulates	3.4 millirem/yr.	0.14 millirem/yr.

Due to partial evaporation of coolant in evaporative cooling towers, the natural concentration of contaminants, such as mineral salts, that enter the system in the make-up water continually increases. These increases are controlled through periodic blowdown of coolant, whereby portions of the coolant are withdrawn and replaced with fresh coolant. Because of the concentration of impurities, the blowdown can be environmentally damaging when discharged to receiving waters. Waste-water treatment techniques can be used to remove impurities prior to discharge of blowdown. "Zero discharge" plant designs incorporating total recycle of plant water are available. Typically, a large power plant, whether nuclear or fossil-fuel, requires about 40 or 50 cubic feet per second of water for cooling, assuming it uses evaporative cooling towers. About two-thirds of this amount is evaporated into the atmosphere, and one-third is returned to the receiving water as blowdown. The effect of water withdrawals and discharges of this magnitude depends on the receiving water body.

In addition to thermal discharges, there may be release of waterborne radioactive materials, including fission products such as nuclides of strontium and iodine, activation products such as sodium and manganese, and tritium. Standards are established to control internal doses, if any, from fish consumption, from water ingestion (as drinking water), from eating, and from any direct external radiation from recreational use of the water near the point of discharge. Monitoring programs are established to ascertain that standards are not exceeded.

Waste Disposal

Solid waste from nuclear power plants include those common to any industrial plant as well as the radioactive wastes related to the unique aspects of the nuclear process. The latter are by far the most significant.

Radioactive isotopes produced as a result of reactor operation include fission products, actinides and activation products. *Fission products* are radioisotopes formed as the products of the fissioning of uranium and plutonium during reactor operation. *Actinides* are the isotopes of elements, of atomic weight 89 (Actinide) and greater. For commercial reactors, the actinides of greatest significance include residual amounts of unfissioned uranium fuel plus unfissioned plutonium and heavier actinides formed by transmutation of uranium during reactor operation. *Activation* products include radioisotopes formed by neutron flux during reactor operation.

The classes of radioisotopes described above appear in a variety of physical and chemical forms during the course of reactor operation. Airborne particulates and gaseous wastes were discussed earlier; the solid waste forms will be discussed here.

Techniques for treatment and disposal of radioactive waste depend upon the physical and chemical characteristics of the waste form as well as the radiological characteristics of the contained isotopes. For purposes of determining the general method of final disposal, radioactive waste is classified as high-level waste, transuranic waste or low-level waste.

High-level waste has high concentrations of beta and gamma-emitting isotopes and may have significant concentrations of transuranic materials (isotopes of neptunium and heavier elements including plutonium). The only reactor product within the category is spent fuel. Spent fuel must either be reprocessed to recover uranium and plutonium or it must be treated as waste. Reprocessing will not be common practice for a long time, if at all. Transport to disposal sites or reprocessing plants raises concerns regarding highway accidents, accidental spillage, and theft. Short of accidents or willful sabotage, the transfer of wastes are expected to result in no damage to the environment or to fish and wildlife with the exception of the land developments, which could affect wildlife.

Transuranic wastes have significant amounts of alpha-emitting transuranic isotopes and low levels of beta and gamma emissions. Transuranic wastes are produced during normal reactor operation, but are contained within the spent fuel elements unless the fuel cladding is breached.

High-level and transuranic radioactive wastes containing significant concentrations of long-lived isotopes must be isolated for thousands of years. Pursuant to federal statute, work is now underway to choose suitable disposal sites for spent nuclear fuel and high-level wastes. Under current planning, disposal of high-level waste in the United States will be in a deep geologic repository, although surface storage with adequate monitoring has many proponents. Monitored retrievable storage keeps options open to reprocess the fuel at a later date, and allows for corrective actions in the storage of the waste. On the down side, retrievable storage increases the risk of sabotage and accidents from acts of war or nature. Spent reactor fuel is currently held in storage at reactor sites, pending implementation of a federal spent-fuel disposal system.

Finally, low-level wastes are characterized by relatively low levels of beta or gamma emissions and insignificant concentrations of transuranic materials. Low-level wastes produced during reactor operation include gaseous waste, compactable and combustible wastes, concentrated liquids and wet wastes, and non-combustible operating and decommissioning wastes. Disposal of low-level wastes is either by dilution to acceptable levels and release or by shallow land burial. Compactable and combustible wastes are reduced in volume by compaction and incineration, packaged and placed in shallow land burial sites. Liquids and sludges are solidified, packaged and placed in shallow land burial sites. Non-combustible operating and decommissioning wastes are packaged and placed in shallow land burial sites.

Typical high-level and low-level radioactive waste production from commercial nuclear power plants is summarized in Table 9-4.

Decommissioning

One method of decommissioning a nuclear power plant requires the removal of all fuel. Next, the plant is sealed and cooled for 10 years, during which time the site must be monitored and isolated. The reactor building is then covered to withstand natural forces for 200 years. All expected costs of decommissioning are included in the Council's estimated cost of producing power.

Summary of Environmental Effects: A summary of the primary (first order) environmental effects of a representative nuclear power plant is provided in Table 9-5.

Geothermal

The principal environmental concerns regarding geothermal development in the Pacific Northwest are air, water and noise impacts, land subsidence, effects on water supply, wildlife habitat, aesthetic impacts and land-use conflicts. To a large extent, many of these impacts can be mitigated.

Air Impacts

Impacts of a single geothermal facility on air quality are closely related to the non-condensible gas content of geothermal fluid. Although these impacts are usually minimal when viewed from a regional or national perspective, they may be significant in a given locale, because of site-specific factors. The concentrations of non-condensible gases in geothermal fluids are highly variable from field to field and even from well to well.

Non-condensible gases may include carbon dioxide with lesser amounts of ammonia, methane, hydrogen sulfide, mercury, radon, boron and trace metals.

Table 9-5
Summary of Environmental Impacts for Representative Nuclear Power Plants

Air Residuals	Light Water Reactor[a] Annual Level	Per Megawatt-Year
Sulfur Dioxide (SO_2) (lb.)	Negligible	Negligible
Oxides of Nitrogen (NO) (lb.)	Negligible	Negligible
Total Suspended Particles (TSP) (lb.)	Negligible	Negligible
Carbon Dioxide (CO) (lb.)	Negligible	Negligible
Airborne Radioactive Releases (Ci)	11,000-33,000[b]	15-45[c]
<u>Water Use</u>		
Gross Water Use (gallon)	5.7×10^9 [d]	7.5×10^6 [d]
Consumptive Use (gallon)	5.7×10^9 [d]	7.5×10^6 [d]
<u>Thermal Effects</u>		
Reject Heat (Btu)	45×10^{12}	60×10^9
<u>Solid Waste</u>		
Spent Fuel (lb)	50-60,000	70
<u>Land Requirements</u>		
Site (acres)	200[e]	0.3[f]
Exclusion Area (acres)	7,260[e]	9.7[f]

a 1,250 megawatt unit, 60 percent capacity factor, 10,260 Btu per kilowatt-hour.
b 11,000 for pressurized water reactor; 32,900 for boiler water reactor.
c 15 for pressurized water reactor; 45 for boiler water reactor.
d Using closed-cycle cooling.
e Site and exclusion area totals.
f Per average megawatt energy production.

Non-condensible gases come out of solution during the depressurization of geothermal fluids for steam formation. Principal sources include condenser gas ejection, cooling tower exhaust, power plant bypassing during shutdown and well venting. Hydrogen sulfide is the most troublesome non-condensible gas, because of its odor, even at low concentrations. At higher concentrations, it affects the nervous system by causing excitement and dizziness. Hydrogen sulfide poisoning can result in respiratory failure. Contemporary flash-steam geothermal power plants, such as those likely to be constructed in the Northwest, collect and reinject non-condensible gasses to the geothermal reservoir.

The greatest danger from hydrogen sulfide is to drilling crews during drilling. Available mitigation measures normally include detection and alarms, emergency breathing equipment, well-shutdown procedures, mufflers with scrubbers, and chemical solutions that can be injected to remove hydrogen sulfide.

Concentrations causing discomfort, but not posing a risk to public health or welfare occur at generating facilities. Several treatment technologies have been developed for generation plants, including those that create sludge as a waste product and need proper disposal. Present evidence indicates that hydrogen sulfide will not cause severe vegetation damage. Various state and federal agencies are proposing emission limits for hydrogen sulfide.

Boron has been determined to cause symptoms of stress and serious damage in some tree species. It is unclear whether it would be considered a serious environmental hazard at this time. Boron can be removed before being vented to the atmosphere.

Non-condensible gases appear to be a minor problem when resource development uses binary generating technology. Binary systems use a closed system to handle geothermal fluids, thereby reducing or eliminating their exposure to the atmosphere.

Water Impacts

Water pollution could occur at any stage of geothermal exploration or development. Many regulations and operating orders are intended to prevent contamination. Surface water or groundwater can be contaminated by drilling mud, which may contain petroleum-based additives; by blowouts, in which a well casing ruptures, and geothermal fluids mix with surface water or near-surface aquifers; by rock cuttings that contain toxic chemicals; and by surface erosion during construction. Most of these conditions can be prevented by isolating the surface water or groundwater from possible contaminants. This is done by using sumps with impervious linings, properly designed wells and casings, and removal of toxic wastes to acceptable disposal sites.

The most serious potential contaminant is "spent" hydrothermal fluids. Ways of disposing of the fluids include evaporation, surface spreading and injection. The method used depends upon the quantity of waste water. Contemporary flash-steam and binary plants reinject spent geothermal fluids to the reservoir. This has the added advantage of maintaining reservoir fluid levels. Injection into the producing aquifer is the preferred method, especially when fluids contain brine (salts) and other potential pollutants. This method has the advantage of helping to maintain the long-term productivity of the field by returning fluids to the geothermal reservoir. Subsurface disposal is regulated by the Environmental Protection Agency regulations and by state programs developed under the Safe Drinking Water Act.

Another serious concern is disturbance of aquifers during drilling or reinjection of spent fluids. These aquifers can be accidentally polluted, either chemically or thermally.

Noise Impacts

A number of significant noise sources are associated with development and utilization of geothermal resources. These sources include sounds from diesel engines used in construction machinery, compressors and well drilling equipment; compressed air releases; turbines; gas ejection; cooling towers; and venting of geothermal steam during well testing and plant shutdowns. For example, the noise level from venting an unmuffled well can reach 130 decibels (about the level of a jet on takeoff). The noise levels for drilling could reach 90 decibels, and a cooling tower for a 100-megawatt power plant could reach 84 decibels (slightly higher than a busy street corner in a city). If sensitive receptors such as recreation areas are located closer than one mile, there is likely to be some annoyance or complaints, unless additional mitigation steps are taken. Preliminary noise studies from The Geysers in California on wildlife impacts indicate that moderately increased sound pressure levels up to 100 decibels do not produce any drastic changes in wildlife communities. Some evidence indicates that certain species are displaced from noisy areas, but noise has not been proven to be the causal factor.

Noise shielding by terrain, earth berms, vegetation and equipment can mitigate noise levels. Full use of demonstrated noise control technology can reduce most source noise to levels acceptable to quiet rural communities at a distance of 1,000 feet.

Land Subsidence

The removal of large amounts of geothermal fluids from a geologic formation may cause land surface subsidence (sinking). Permanent and non-recoverable subsidence results from long-term removal of fluids and from the compression of aquitards such as clay, silty material or shale above and below a reservoir.

Subsidence problems can be mitigated through injection of spent geothermal fluids (or other sources of water), which serve to maintain pressures within the resource. Even with mitigation, there still could be some localized sinking around production wells and some uplifting around injection wells.

Reinjection of spent geothermal fluids from electrical generation conserves the resource and is the usual preferred disposal method for the fluid in the United States.

Water Supply

Geothermal power production typically requires large amounts of water for condenser cooling. Evaporative cooling systems with mechanical draft cooling towers normally are used. The source of this water is usually the condensed steam from turbines. At The Geysers, for example, about 80 percent of the condensed water from turbines is used as cooling tower make-up. The remaining 20 percent is injected back into the geothermal reservoir.

Binary systems (in which all geothermal fluids are reinjected) can require large volumes of water from sources other than geothermal reservoirs for cooling. These sources can include lakes, rivers or groundwater aquifers.

Wildlife Habitat

Human activity associated with exploration and development may intermittently affect patterns of wildlife habitat. Exploration activities are generally low-density and short-term, ranging from a few days to a few months. If development takes place, activity would substantially increase during construction and development, but would be reduced to a lower level during production. The production phase would last for 30 years or more.

The timing and location of activities in relation to key habitat and use patterns would determine the significance of displacement or disturbance. Potential conflicts would be greatest in areas where wildlife congregate and during periods of migration and reproduction.

Stipulations that restrict the season of use could be used to mitigate the effects and protect sensitive wildlife habitat.

Land Use/Aesthetics

The amount of land where vegetation will be lost varies with the type of generating facility. For example, well-head generators and small plants (5 to 10 megawatts) have different requirements for space than do large centralized plants (50 to 100+ megawatts). Typically, centralized plants and related developments occupy from 5 to 20 percent of the surface area of the geothermal field. The plant site is used intensively and would require clearing forested areas. Field size could vary from 100 acres to several thousand acres. Field development is less intensive and includes scattered well pads and fluid collection and reinjection piping from the plant to each well. If, for example, one assumes that there is potential to produce electrical energy in amounts ranging from 500 to 1,000 megawatts, the amount of surface area affected by development could range from 750 to 1,500 acres. (These acres would not be contiguous.) If the geothermal resource was depleted, the area would be reclaimed, including revegetation with appropriate species.

Geothermal development often occurs near natural and wilderness areas. Because geothermal development is an industrial activity in an otherwise natural area, this can conflict with the aesthetics of these areas.

Solar Thermal and Solar Thermal with Natural Gas

Solar thermal resources affect land use during construction and thereafter.

Production of Electricity

Production of electricity using solar resources creates no air pollutants. Heat exchange fluids can be quite toxic and spills are possible. Luz International[13] has experienced some leakage of toxic fluid from piping onto the desert floor. Any damages will be confined to the plant site, as no effluents are emitted into the air. For the solar thermal/gas hybrid option, the operation of the plant in the Northwest would result in using gas about 70 percent of the time. Thus, environmental effects of a gas unit would be weighted 70 percent and those of the solar fraction 30 percent. Given that a stand alone solar generator is

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13./ Luz International is a manufacturer of utility-scale solar generating facilities.

environmentally better than gas-fired generation, the solar hybrid also would be environmentally better, albeit to a lesser degree.

As indicated, some leakage of toxic fluids from the piping onto the desert floor has occurred. The clean up required is similar to that required for PCB spills. This problem could be mitigated with better seals on piping, although the operating temperatures make this difficult. Luz is considering using steam instead of synthetic oil as the heat-exchange medium in future plant designs.

Solar Photovoltaic

Production of Electricity

Solar photovoltaics are being made with many different materials. Single crystal silicon or amorphous silicon cells have few potential environmental effects. However, some of the more-efficient cells contain toxic materials, such as gallium arsenide and cadmium sulfide. Water that comes in contact with these cells during the manufacturing process will have to be treated carefully to avoid contaminating nearby groundwater.[14] In addition, these cells may cause a waste disposal problem at the end of their lifetime.

In production, a fire could potentially release some of the toxic chemicals used in the manufacture of the solar cells. In general operation, the levels of environmental effects should be very close to nil.

Wind

Production of Electricity

Using wind to generate electricity produces no pollutants, per se. Environmental effects include aesthetic concerns, land-use impacts, noise, interference with radio signals and possibly some disruption in migratory patterns of birds. Future wind power studies should examine these potential effects further, and mitigation techniques should be identified. Wind turbines alter the aesthetics of shorelines, mountains, gorges and other areas with typically high winds. Each of these effects are site-specific and may or may not cause significant concern among citizens, depending on the site.

The need to avoid obstructions around wind generators may require restrictions on certain types of land use. The Council recognizes that wind generators do not pollute the air, use water, create solid waste and probably would not cause severe "boom town" effects. With proper control, erosion, siltation and water pollution can be avoided. Wind generators do not affect free-flowing rivers and can probably be sited with minimal impact on wildlife habitat. The Council expects wind power

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14./ Environmental effects associated with the manufacture of plant parts have not been addressed for any other resource. They are mentioned here, because the Council received comment that we should address this issue. However, these effects will not be considered in the summary at the end of this document.

to be a desired energy resource for the region with little or no adverse environmental impacts, especially when considered relative to fossil-fuel-fired plants.

Hydropower

The development process for the Council's Columbia River Basin Fish and Wildlife Program, adopted November 15, 1982 and amended October 10, 1984, provided a wealth of information on the effects of hydropower development on fish and wildlife as well as measures for mitigating those effects. Those considerations also were taken into account in development of this plan.

The effects of hydropower generation are limited generally to the stream and fisheries affected by a dam. That is, no serious air pollution or solid waste problems are raised by hydropower projects, and they do not rely on a finite fossil fuel. Since new large dams are not contemplated, the effects described below focus on high-head, run of river or diversion hydropower projects.

Construction and Operation

Construction of a hydropower project may result in erosion and sedimentation near the stream, causing increased water turbidity. These effects can reduce the aesthetic quality of the stream as well as harm its value for fish, wildlife and recreational uses. Sometimes these effects are limited to the period of construction and are not considered significant enough by themselves to warrant foregoing otherwise feasible hydropower sites.

Hydropower plants can block downstream movement of gravel and some sediment. Loss of fish spawning and rearing habitat may occur. This effect can be mitigated somewhat by habitat restoration projects downstream.

Among the adverse impacts on migrating and resident fish are turbine-related mortality, migration barriers, dewatering of streams, alteration of flows, inundation of habitat and the effects of increased travel time. Although they are not entirely effective or feasible in all locations, mitigation measures include fish screening and bypass systems, spilling water to aid fish for passage, fish ladders, establishment of minimum flows and flow augmentation.

Another impact is nitrogen supersaturation caused by excessive spilling of water over the dam. Although lethal to fish, this effect can be and has been mitigated with the use of devices that deflect spilled water. Nitrogen supersaturation also can be the result of entrainment of air into the intake/penstock of a high-head project. Baffling to reduce intake vortexing, air-relief valves in the pipeline, and avoidance of negative pressures in the pipeline are mechanisms to address the problem.

Another impact from operations of hydropower facilities can be stranding of adult and juvenile fish or drying out nests when water fluctuates in the stream. These are important fish considerations when designing project components and developing operation criteria where anadromous fish are found downstream of the project.

When a typical project goes online and offline, it causes a fluctuation in flow in the bypassed reach and downstream of the powerhouse. Because the minimum instream flow in the bypassed reach is often relatively small compared to the quantity of water diverted for power generation, the fluctuation inflow can be significant. The problem often is compounded by the length of time it takes for the water to travel from the diversion to the powerhouse, once water diversion is discontinued. Outages may result in frequent, significant flow fluctuations, particularly if the project is fully shut down. A project outage can cause a decrease in flow and river levels below the powerhouse. This decrease in flow causes downstream habitat to be dewatered. Dewatering habitat can strand and kill juvenile and adult salmon on exposed gravel bars and in dewatered side channels and potholes. A similar problem occurs when a nest is dewatered, the difference being that eggs or yolk sac fry are the life stages affected.

Mitigation recommendations include installation of a flow continuation valve (or a turbine design that performs a similar function) in the powerhouse, identification of critical flow levels, and the establishment of downramping (flow reduction) rates. A flow continuation system, one that maintains the powerhouse discharge during an outage while dissipating the water's energy, is the best way to minimize operation impacts, because it eliminates the fluctuation under many circumstances.

Federal law prevents licensing hydropower projects on or directly affecting wild and scenic rivers, and special consideration is required when Indian lands, Indian fisheries, historic or archaeological sites, national wildlife refuges, national monuments, national recreation areas, national parks, endangered species habitat or lands adjacent to wilderness are involved. In estimating the amount of hydropower potential for the 1983 plan, the Council accordingly eliminated such areas from consideration.

In addition, on August 10, 1988, the Council adopted a proposal to designate some 44,000 miles of streams throughout the region as protected from new hydropower development because of their importance as critical fish habitat. In adopting this proposal, the Council concluded that hydropower development in the designated areas would have major negative impacts that could not be reversed and that protecting these resources is consistent with an adequate, efficient, economical and reliable power supply. Following adoption of this proposal, the Federal Energy Regulatory Commission recognized the Council's plan and program as a comprehensive plan under the Federal Power Act, which means that the Commission will consider the Council's plan and program in reaching decisions on licensing future hydropower projects. As a result, this plan excludes hydropower development in those areas designated by the Council as protected from new hydropower development.

Installation of hydropower projects on a previously free-flowing stream also can reduce or eliminate the stream's value for kayaking, rafting and some types of fishing, as well as reduce the forest land base and affect Indian religious sites. Also, although the effects of particular projects may be relatively minor, the cumulative effects of several hydropower dams on a single stream or in a single basin, drainage or subbasin can be serious. As a result, this plan includes measures to allow future hydropower development only at the least sensitive locations and with minimum environmental impact.

Because of these safeguards, the Council believes necessary additional hydropower development can occur in an environmentally sound manner. The first hydropower included in the plan will be needed in the early 1990s.

Conservation

Conservation will be a key contributor of energy in the resource portfolio no matter how future electrical loads grow. Large amounts of conservation are available from a variety of technologies in almost all energy consuming activities throughout the region. The construction phase of conservation has identical environmental effects as the construction of buildings. For new buildings, the incremental effect of installing conservation measures is virtually nil. For existing buildings, there are clearly some effects, but they are too small to be of concern for this paper.

Indoor Air Quality

The primary environmental cost of conservation has been identified as a potential negative impact on indoor air quality. However, this impact can be negligible--or even positive--if appropriate provisions are made for acceptable indoor air quality and adequate ventilation when conservation measures are installed. The fear is that energy-efficient buildings will have less ventilation than ordinary buildings. In buildings with less natural air leakage, the potential exists for higher concentrations of normally occurring indoor air pollutants.

Formaldehyde, radon, volatile organic compounds and combustion by-products, such as benzo(a)pyrene, are the indoor air pollutants considered the major potential health risks in residential and commercial buildings. Health effects of inhaling higher than average concentrations of these chemicals can range from headaches and sore throats to increased chances of incurring lung cancer. Moisture (i.e., humidity) is also perceived as an indoor air pollutant when it becomes excessive, contributing to the growth of molds, mildews and fungi.

Pollutants can enter a home from a variety of sources. These include the materials used to build the home, the appliances and furnishings within it, materials smoked in the home, chemicals brought into the home, cooking and even the taking of showers. In general, new energy-efficient homes and new conventional homes do not differ significantly in their sources of pollutants.

The amount of pollution within a building depends on three factors: the strength of the source, the ventilation rate of the building and the rate at which the pollutant is removed from the air by chemical reaction or physical processes. The source of the pollutant is a very important factor. If there is no source in the home to start with, there is no need to remove it. Although some pollutant sources are unavoidable, many pollutant sources can be avoided or minimized at the time a building is constructed or remodeled. For example, formaldehyde off-gassing can be reduced through the use of low-fuming formaldehyde wood products rather than the use of ordinary plywood and particle board. Reducing the source of pollution can have significant beneficial impacts in either an energy-efficient or a conventional home.

There have been many studies throughout the world during the past decade to better understand the relationship between indoor air quality and energy conservation. These studies are showing that properly built energy-efficient homes are no more prone to indoor air quality problems than non-energy-efficient homes. This is partially due to the fact that even if an energy-efficient home has a lower air-exchange rate (ACH), it does not necessarily have worse indoor air quality. This is because so much depends on the source of the pollutant being present. Studies are showing that very leaky houses can have indoor air pollution problems, while relatively tight homes can have very low levels of pollutants. These findings indicate that strong pollutant sources can overwhelm ventilation. However, at lower pollutant levels, ventilation is one important means for pollution control. In addition, ventilation rates at point sources may be more important than the average ventilation rate. In some cases, energy lost through ventilation can be recovered through heat exchangers and heat pumps in the effluent stream.

The Council has taken significant precautions to ensure that conservation actions do not worsen indoor air quality. Houses and commercial buildings built to the model conservation standards must have equal if not better indoor air quality than current practice buildings. The potential indoor air problems discussed above have been internalized by the requirement for adequate indoor ventilation in any program aimed at tightening structures to save energy. Residential model conservation standards require mechanical ventilation, radon mitigation packages and spot ventilation to achieve this goal. In addition, model conservation standards require that combustion appliances have access to outside combustion air and that low-formaldehyde products be used in the construction of buildings. Commercial buildings are required to adhere to the ventilation requirements of the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) and the Environmental Protection Agency.

Summary by Resource Type

Table 9-7 displays the physical quantities of air pollutants produced by each of the resources in a megawatt year. A question mark has been inserted where the quantities are currently not known. The effects of these pollutants will depend upon where the plant is located. For example, a ton of particulate matter emitted in a remote area with good dispersion will have less impact than a ton emitted in an area that already has relatively poor air quality.

Table 9-7
Common Pollutants Emitted to the Air
(Tons per Megawatt per Year)

Technology	Total Suspended Particulates	Sulfur Dioxides	Nitrogen Oxides	Carbon Monoxide	Carbon Dioxide
Small Pulverized Coal[a]	1.78	2.00	17.2	1.71	10,368
Large Pulverized Coal[a]	1.76	1.97	16.9	1.69	10,226
Atmospheric Fluidized Bed[a]	1.60	1.80	15.3	1.54	9,313
Integrated Gasified Combustion Cycle[a]		10.3	11.4	?	8,626
Combustion Turbine Gas[a]	.119	.029	7.87	1.91	5,000
Combined Cycle Combustion Turbine Gas[b]	.04	0	2.80	2.23	4,174
Combustion Turbine Oil[b]	1.45	10.3	4.99	5.65	8,006
Combustion Cycle Combustion Turbine Oil[b]	7.62	7.62	1.10	1.10	6,237
Gas Cogeneration	c	c	c	c	c
Biomass Wood[b]	1.88	.57	9.94	18.7	13,183
Biomass Wood Cogen.	c	c	c	c	c
Biomass MSW Ref Der Fl.[a]	.24	3.31	15.0	10.8	?
Biomass MSW Mass Burn[a]	1.43	4.13	13.5	8.34	?
Nuclear	0	0	0	0	0
Geothermal	d	.54[e]	d	d	26[e]
Solar Thermal	0	0	0	0	0
Solar Photovoltaics	0	0	0	0	0
Wind	0	0	0	0	0
Hydropower	0	0	0	0	0
Conservation	0	0	0	0	0

a *Compilation of Air Pollutant Emissions Factors: v. 1 Stationary Point and Area Sources*, Joyner, Michael W., Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, 1985.

b *The Treatment of Environmental Impacts in Electric Resource Evaluation: A Case Study in Vermont*, Bernow and Marron, Tellus Institute, Boston, Massachusetts, January 22, 1990.

c All cogeneration facilities will have fewer impacts than a stand-alone unit, because cogeneration will offset pollutants from another source. Unless the specific fuel and facility being offset is known, the credit to cogeneration cannot be estimated.

d We have not found good emissions data for geothermal plants, probably because the effluents are so dependent on the chemistry of geothermal resource and partly because of an assumption that closed-loop systems do not emit much to the atmosphere.

e These are emissions from CEEI's Coso units, which are thought to be typical.

The information presented in the text of this document and the physical pollutants emitted to the air, shown in Table 9-7, have been synthesized into a summary of environmental effects and the environmental risk faced with each resource alternative. Environmental risk represents exposure to future direct environmental consequences, such as a nuclear accident, as well as the risks of future costly regulation, taxes, or ultimate prohibition. Such a prohibition could result if it is determined that the environmental damages are greater than was believed earlier.

The following summary paragraphs for each resource represent an environmental perspective only; therefore, decisions about which resources to include in a power plan cannot be made solely on this information. The Council could determine that other qualities of resources, such as availability, reliability or costs, justify incurring larger environmental damages. If, for example, other technologies do not mature as envisioned in the Council's plan, coal-fired plants may be the only category of resources capable of meeting loads, even though coal's environmental effects appear to be greater than other alternatives. Also, it should be recognized that very few resources are environmentally benign. Virtually all of resources have some environmental problems, although some clearly have fewer adverse effects.

The actual environmental effects of any plant will be not only based on the plant's emissions to air, water and land throughout the fuel cycle, but also on the location of these activities relative to prevailing winds and potentially affected populations. Because the locations of plants are not known, the implicit working assumption used here is that all plants are located in the same position relative to potentially affected agents. In reality, this might not be the case, as gas-fired plants are more likely to be placed closer to population centers because of their relatively less severe environmental impacts.

Coal Plants

Coal-fired generation probably affects the environment more than any other alternative, although "clean coal" technology has decreased remarkably the amount of pollutants typically emitted from coal plants. Of all the resources included in the Council's resource portfolio, coal plants have relatively more damaging environmental effects. Air, land and groundwater are affected at the mining and combustion stage. No other resource affects the land as adversely during the exploration and mining phase as does coal mining, with the possible exception of oil exploration and development in pristine environments. Rail transportation of coal also affects air quality and disrupts traffic patterns in some towns as 100-car unit trains pass through. Transportation of coal also appears to have more continuing environmental effects than transportation of fuels associated with other resources. Transportation of oil could have more catastrophic environmental problems, but these problems are considered as an environmental risk, as opposed to a continuing effect.

Combustion of coal, even at relatively clean plants,[15] emits more of the major pollutants into the atmosphere than other resources. Per unit of output, coal plants emit more particulates, more sulfur dioxide and more nitrogen dioxide than

15./ Coal plant emissions being considered here and shown in Table 9-7 are assumed to have controls that remove 99.2 percent of all particulates, 95 percent of all sulfur dioxide and 60 percent of all nitrogen dioxide. This level of control is greater than that required by federal new-source performance standards, but does not represent the very best technologies.

any other resource. Coal plants also emit more particulates than every resource except biomass. Only biomass generators emit more carbon monoxide and hydrocarbons. Each of these pollutants affects the air, water and land in adverse ways. These effects are described in this and Chapters 7 and 8 of this plan.

Disposal of ash sludge can require up to 1,400 acres of landfill for a 500 megawatt plant. Since the ash contains toxic elements, it is difficult for vegetation to grow after the sludge is buried.

Since coal plants represent a large project for most locations, their construction can create peaking problems for a community's infrastructure. Often, the cost of expanding local services to accommodate the influx of construction crews and other related personnel is added to the cost of the plant. To the extent that these costs are included for coal plants and all other plants, this issue is resolved. In general, the effects of construction on communities and their infrastructure are both positive and negative and are not as important as the effects from pollutants emitted throughout the fuel cycle.

Coal is also considered to be the most environmentally troubling resource when considered from its effects on the human and natural environment. Effects on man's environment are more severe than for other resources in exploration, mining, transportation and combustion. However, the effects of pollutants emitted during the production of electricity are the ones of most concern. Coal produces more particulates than other resources, and these particulates can attach themselves to toxic gases and be inhaled. Coal plants are also the largest emitters of nitrous oxides and sulfur dioxide, the precursors of acid rain, which affects vegetation, rivers, lakes and fish, as well as buildings, bridges and other physical structures. Finally, of all generating resources, coal emits more of the gases that experts link with global warming than other resources. Table 9-7 shows that coal plants emit from 8,600 to 10,400 tons of carbon dioxide per megawatt a year. Wood biomass resources also produce a considerable amount of carbon dioxide, but trees grown for fuel have zero net effect on the total amount of carbon dioxide emitted, because they remove carbon dioxide from the atmosphere as they grow and then give it up when they are combusted.

Finally, coal also is considered to be an environmental risk mainly because of the uncertainty imposed by the fears of global warming. Should the worst fears of scientists be realized, operating coal plants could be assessed a tax on carbon dioxide emissions or, at the extreme, be prohibited from operating.

Natural Gas

This category includes single-cycle combustion turbines and combined cycle combustion turbines. Gas is a relatively clean fuel compared to coal. Particulates and sulfuric oxide emissions are quite low, as can be seen in Table 9-7. Nitrogen dioxide levels from gas plants can be high, although there is control technology to reduce nitrogen dioxide to fairly low levels (five parts per million down from 25 parts per million). We have assumed that this technology is not incorporated into the plant. If it were added, the capital and operating costs of gas-fired plants would increase.

Gas contains about 50 to 60 percent of the carbon contained in coal per million Btu of fuel, and a gas-fired plant has a heat rate that is 70 percent of a coal plant's rate. Thus, the production of greenhouse gasses from gas-fired plants is about 40 percent of the amount from coal plants.[16] Gas-fired plants are second to coal in the net production of greenhouse gasses. Because of the global warming issue, gas-fired generators impose some risk to developers of incurring costs for future mitigation of carbon dioxide. The effects of gas on water and land are limited to the effects of exploration, development of wells and pipeline construction. On a per Btu delivered basis, the effects of these activities are considered to be less than similar activities related to coal mining and transportation. The negative effects of gas-fired plants on the human and natural environment are about 50 percent less than those from coal-fired plants, because of the lower emissions, shown in Table 9-7, and information relating to the effects of the natural gas fuel cycle on land and water.

Natural Gas as a Resource to Firm Nonfirm Hydropower

Natural gas-fired plants used in the Northwest would not operate as often as they would if they were located in another region, because the plants would not be run when nonfirm hydropower is available. It is expected that the plants will run, on average, about 35 to 40 percent of the time. Thus, the environmental effects associated with plant operation would be about 35 to 40 percent of those listed in Table 9-7. In essence, each megawatt-year would be a mix of 35 to 40 percent generation using gas as a fuel and the remaining 60 to 65 percent would use water as a "fuel."

Oil-fired Combustion Turbines

The single-cycle combustion turbines and combined-cycle combustion turbines described in this plan can be fired with oil as well as natural gas. Exploration and development of petroleum are similar to natural gas, but transportation of oil presents both an ongoing minor problem and represents a large environmental risk, as has been shown in recent spills in Alaska and off the coast of Africa. In addition to the transportation issue, the combustion of oil, although it does not result in the levels of pollutants associated with coal plants, is clearly less desirable than burning natural gas. Therefore, the environmental effects of oil-fired power plants fall somewhere between coal and natural gas-fired plants. Oil and gas are relatively risky, because they both contribute to greenhouse gasses, which could result in the plants being required to be retrofit at some time in the future. Oil has an additional risk related to ocean spills.

16./ In addition, leaks from natural gas burners and pipelines release some amount of methane, which is also a greenhouse gas.

Biomass: Wood

Wood-fired power plants emit about the same amount of particulate matter as coal plants and about 30 percent of the sulfur oxides. Nitrogen oxide emissions from wood-fired generators are similar to those of combustion turbines, and about 70 percent of a coal plant's emissions. Although the amount of carbon dioxide emitted is large, as can be seen in Table 9-7, combustion of wood is a zero net contributor to greenhouse gasses. This is because trees take up carbon dioxide from the air. Thus, when the wood is combusted, it gives up only the carbon dioxide that it removed from the atmosphere. The severity of the environmental effects of wood-fired plants falls between gas and oil-fired generation, but wood is not as risky as these other fuels, because it can help delay global warming. If global warming becomes a real political concern, the effect on wood burning would be to increase its use, probably within a scheme to grow and harvest a sustained yield for electricity production. Other pollutants emitted to the environment during the combustion of wood can be controlled as easily as they can be controlled in other plants burning coal or oil. The collection of wood and transportation to the plant site results in no environmental degradation that would not have occurred with disposal of the wood residue in any other way.

Biomass: Municipal Solid Waste

Municipal solid waste can be burned without sorting in a "mass-burn" facility, or the garbage can be sorted to eliminate non-combustible items from the waste. Sorted fuel is referred to as "refuse-derived fuel." Mass-burn facilities have more severe environmental effects than facilities burning refuse-derived fuel, because there are more toxic substances that remain in the waste stream. The pollutants of major concern with resources that burn garbage are not necessarily the major resources addressed in Table 9-7, but instead are the toxins that can be released from plastics and other unknown elements in the waste. As far as the pollutants addressed in Table 9-7 go, these resources emit about the same level of particulates as coal plants and oil-fired plants. Sulfuric oxide emissions fall within the levels emitted by coal and oil plants, and nitrous oxide emissions are about the same as coal plants. The emissions of municipal solid waste burning to the air and water are judged to be about the same degree of severity as those emitted by oil-fired plants. The effects on the land at the waste disposal stage is about the same degree of severity as the effects of waste from coal plants, although the effects are obviously less at the "mining" stage. However, because the alternative of landfills has to be considered, the effects of waste disposal from municipal solid waste plants is not a major incremental concern. That is, if the refuse were not burned, it would have to be buried. With burning, only the residual ash, which has much less volume than the garbage itself, has to be buried. The overall effect on humans and their environment is considered to be at about the same level as oil-fired plants.

Nuclear

The normal environmental effects of greatest concern associated with the nuclear fuel cycle fall into a different category than those addressed for other resources. Uranium miners face health risks, as do coal miners, and uranium mining disrupts land as does coal mining, albeit to a smaller degree.

However, the key environmental effect from nuclear plants is the risk of an accident. It is difficult to think in terms of expected damages when an event such as a nuclear accident can have huge consequences, but is a low-probability event. Even though the probability is low, it appears that a large segment of the public believes the environmental risk from nuclear plants is great. Thus, regardless of what the probabilities are, nuclear resources will continue to suffer from the risks as perceived by the public. This affects the ability of anyone to acquire the nuclear resource.

In nuclear plants, emissions of the type of pollutants found in fossil-fuel burning plants are virtually nonexistent. However, nuclear has its own set of emissions, reported in Table 9-5. Because the emissions are different from those for other resources, it is difficult to summarize the relative effects of nuclear power, based on its emissions to air, water and land. However, it appears that nuclear's overall effect on the environment is about the same as natural gas. Both have environmental risks, although the risks are dramatically different. Gas plants could see increased controls, depending on the outcome of further global warming research, whereas the nuclear risk is based on accidents, sabotage, "acts of God" and war.

Solar Thermal, Solar Photovoltaics and Wind

Compared to all other resources except conservation, solar thermal, solar photovoltaics and wind are relatively benign. Environmental problems are clearly local in nature and probably will be dealt with by effective zoning ordinances. From a regional planning perspective, these resources probably will not be limited because of environmental concerns.

Geothermal

The environmental concerns with geothermal resources also are somewhat different from those of typical fossil-fuel-fired plants. Geothermal has its own unique set of problems. Development is often located in remote areas that can conflict with other non-industrial uses in contiguous areas. Development of fields can require a large land area, and emissions from plants can be quite toxic. Emissions can be largely controlled with the proper reinjection technology and a closed-loop system.

The environmental effects from geothermal resources are about the same in relative severity as from wood-fired generation. Both of these resource types are renewable, with some lag time, but they are not as environmentally sound as the other broad group of renewables, which is comprised of solar and wind technologies.

Hydropower

The Council has made major decisions based on the environmental effects of hydropower development and operation. Approximately 44,000 miles of stream reaches have been identified as critical habitat, where hydropower development is not appropriate because of the damage development and operation would cause to fish and other important resource values. Those sites that are left have no known important fish or wildlife concerns and, therefore, have relatively benign environmental effects. The biggest effect remaining is on water use and quality in the streams that would be developed. However, new hydropower outside of the protected areas appears to be environmentally better overall than many of the other alternative resources. The environmental consequences of hydropower development are at about the same relative level of severity as solar thermal resources. However, hydropower development is somewhat riskier because of possible future fish, erosion, water use and water quality concerns.

Conservation

This is the most benign resource of those considered. Its key environmental problem, indoor air quality, can largely be mitigated during conservation acquisition efforts.

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APPENDIX 9-A

METHOD FOR DETERMINING QUANTIFIABLE ENVIRONMENTAL COSTS AND BENEFITS

Priority is given in the plan to resources that are cost-effective. The Bonneville Power administrator is required to estimate all direct costs of a resource or measure over its effective life to determine if a resource or measure is cost-effective. Quantifiable environmental costs and benefits are among the direct costs of a resource or measure. The Act requires the Council to include "a methodology for determining quantifiable environmental costs and benefits" in the plan. This methodology will be used by the administrator to quantify all environmental costs and benefits directly attributable to a measure or resource.

Proposed Method

A. Identify the characteristics (technical, economic, environmental and other) of the resource or measure in question. Quantify each identified environmental effect in terms of the physical units involved (e.g., acres of habitat, tons of sulfur dioxide, change in water temperature).

B. Identify all potential environmental costs and benefits (e.g., the economic value of the effects of changes in the environment) that will result from the resource or measure. Each one of the environmental studies previously completed by the Council should be subjected regularly to public review, comment and improvement. Research to identify the environmental costs and benefits of each resource should be continued by Bonneville in light of advancing knowledge about environmental impacts and of technical changes in resources.

C. Screen the identified environmental costs and benefits to determine whether a meaningful economic evaluation can be performed. In making this determination, reference should be made to the work products of the Council--Study Module VI, Nero and Associates, Inc., Reports to Council (Tasks 1-6) on Quantification of Environmental Costs and Benefits, Contract 82-020. In particular, consideration should be given to whether economic techniques are sufficiently developed to allow for a meaningful analysis of the environmental cost or benefit.

D. Determine whether environmental costs and benefits that can be meaningfully evaluated in monetary terms will be so analyzed. This determination should include consideration of:

   1. whether sufficient information exists or can reasonably be obtained to allow for an analysis of the environmental cost or benefit;

   2. whether the relative cost-effectiveness of alternative resources is such that the as yet unquantified environmental costs and benefits would likely affect the decision on resource cost-effectiveness; and

   3. whether significant costs or benefits remain after considering the effect state or local standards may have on the environmental cost.

E. For each environmental cost and benefit that can be quantified, an information base that analyzes the amount of information available should be assembled by the administrator to quantify each cost or benefit and assesses the uncertainty affecting the ultimate quantity estimates. Federal, state, and local studies of such environmental costs and benefits, scholarly and professional quantifications and data obtained as a result of public comment should be used to the extent appropriate.

F. A specific economic evaluation method should then be selected by the administrator, based on the type of environmental cost or benefit, data available to characterize the environmental effect and related environmental cost or benefit, experience with the method (e.g., has it been successfully used in the past) and type of uncertainties involved. The strengths and limitations of the evaluation method will vary with each environmental impact, and this should be documented. More than one evaluation method may be needed to cross check and verify results.

G. For those environmental costs and benefits where it is not possible to develop monetary values, key physical and biological parameters should be described and, if possible, quantified.

H. The application of the evaluation methods should then take place. A record should be compiled that describes the resource, indicates what impacts were identified and which measurement methods were selected, documents each aspect of the calculation and supports the final result. Throughout this process, the administrator should consult with the Council, the resource sponsor, interested persons, Bonneville customers, consumers, states and local political subdivisions. The administrator should involve the public to the maximum extent appropriate.

I. All quantified environmental costs and benefits should then be included in the decision on resource cost-effectiveness. Where the environmental costs or benefits have been quantified in other than monetary terms, the administrator should make a decision about the cost-effectiveness of each resource or measure by comparing the dollar cost of resources or measures with such costs or benefits to the dollar cost of competing resources or measures. A determination should then be made as to whether the quantifiable, but unpriceable, costs or benefits are sufficient to make an otherwise less expensive resource or measure, with such unpriceable environmental costs or benefits, more "costly" than the next most "costly" resource or measure.

J. To the extent that no quantification on any terms is possible, the environmental costs and benefits should be identified and described, and an assessment should be made on their probable magnitude in relative terms. The environmental costs and benefits of a resource should be given due consideration by the administrator before the resource is acquired. Such environmental costs and benefits will be weighed in the decision to acquire.

In 1983 and 1984, Bonneville conducted case studies on the environmental costs and benefits of four existing individual resources--a coal plant, a combustion turbine, a nuclear plant and a hydroelectric dam. These studies tested the feasibility of trying to assess environmental costs, using specific estimating techniques. The studies made environmental cost and benefit estimates for each of the four facilities. Generally, the case studies showed that it should be possible to establish costs for environmental impacts.

In 1985, Bonneville undertook to estimate environmental costs for various types of resources on a generic basis. Bonneville hired consultants and conducted a public involvement process to develop generic environmental costs for hydroelectric, geothermal, cogeneration, biomass, wind and solar resources. These reports are available from Bonneville.

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CHAPTER 16

CONFIRMATION AGENDAS FOR GEOTHERMAL, OCEAN, WIND AND SOLAR RESOURCES

Chapter 16
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This chapter describes four packages of coordinated actions intended to foster the prudent development of geothermal, ocean, solar and wind generating resources when needed. Analyses by the Council and others suggest that these resources have the potential to provide a substantial, cost-effective and environmentally sound contribution to the power generating needs of the region. The recommended actions should reduce uncertainty regarding these resources, and thereby improve planning decisions concerning these and other resources. These actions also may accelerate improvements to the cost-effectiveness, reliability and environmental acceptability of these resources, and the ability to develop these resources in a timely manner when they are needed to meet Pacific Northwest energy needs. These actions support the objectives of the Action Plan of the Draft 1991 Power Plan, and form an important component of the research and development element of the power plan, as required by the Northwest Power Act.

The Council, in its 1986 Power Plan, called for the formation of a Research, Development and Demonstration Advisory Committee under the provisions of the Regional Act providing for the formation of voluntary advisory committees to the Council. The Council charged this committee with delivering recommendations regarding necessary actions to resolve uncertainties affecting resource planning and to improve the cost-effectiveness and environmental acceptability of promising resources.

The Research, Development and Demonstration (RD&D) Advisory Committee convened in March 1989. Over the next year, the Committee assembled technical advisory panels for geothermal, solar and wind resources. Recommendations of these technical advisory panels and subsequent deliberations of the RD&D Advisory Committee led to the actions described in this chapter for geothermal, solar and wind resources. The action for ocean energy technologies was developed by the Committee in response to the Council decision in September 1989 requesting the Committee to prepare recommendations for furthering the development of ocean energy resources. The Council, in deliberating the recommendations of the Committee, added the actions involving a wind demonstration project and solar photovoltaic acquisition.

Each action recommended by the Committee is supported by at least a majority of the Committee members. Many of the recommendations are unanimously supported. Members of the RD&D Advisory Committee are listed in Appendix 16-A, and members of the technical advisory panels are listed in Appendix 16-B.

Criteria for Actions

These actions meet three criteria. First, these actions are believed to have a high probability of achieving the objectives of improving planning certainty; fostering resource cost-effectiveness, reliability and environmental acceptability; and improving the ability to develop these resources in a timely manner when needed.

Second, these actions generally are limited to those addressing needs and circumstances unique to the Pacific Northwest. Organizations such as the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (DOE) are positioned to address resource issues of general interest nationwide. But these organizations typically do not address unique regional problems. Moreover, the U.S. Department of Energy emphasizes basic research, whereas an important need of this region is to prepare for the commercial development of these resources. The Northwest must be prepared to support resolution of problems unique to the Northwest.

Finally, the actions are those that should commence within a period of five years. The Council's power plan will be revised by the end of this period, and this resource confirmation agenda can be reassessed at that time or before. Because many of the actions are conditional upon prerequisite actions, and because the need or feasibility of developing these resources may change through time, the agenda will be reviewed annually by the Committee.

Benefits of the Recommended Actions

The benefit of these actions generally lies in the expectation that they will shorten the development lead time and improve the cost-effectiveness of resources generally thought to possess desirable characteristics and to be present in abundance in the Northwest. Equally important, the information resulting from these actions is expected to lead to better decisions with respect to these resources and their alternatives. Demonstration projects will allow the region to gain experience with resources that have received little exposure here and thereby improve the credibility of the resource. More specifically, the principal reasons for these actions are the following:

- Better Resource Planning Decisions: An important element of the Council's power planning strategy is the management of uncertainty. But an equally important planning strategy is the reduction of that uncertainty. Information gleaned from these actions will lead to improved planning decisions through the reduction of uncertainties regarding geothermal, ocean, solar and wind resources. These decisions affect not only these resources, but other resources that might otherwise have to be developed. Foremost among the resource planning benefits of these actions will be confirmation of the feasibility of developing geothermal resources in the Cascade Mountains and the Rocky Mountain Front wind resources.

- Reduced Lead Time: Many of the actions are expected to reduce the lead time required to bring these resources into service when needed. The geothermal demonstration projects, for example, will promote resolution of siting, technical and environmental issues at their respective sites, facilitating development. Council studies indicate that reduction in project lead time is extremely valuable. For example, shortening the lead time for 300 megawatts of geothermal energy by three years is estimated to have a net present value of $80 million.

- Reduced Environmental Impacts: Some of the actions are expected to reduce environmental impacts through better siting and improved environmental mitigation.

Additional benefits of these actions are:

- Reduced Cost: Some of the actions may lead to reduced resource development costs. For example, wind turbulence and shear data will provide better understanding of wind resource characteristics, thereby improving the siting of wind farms. Improved siting should result in higher capacity factors, lower power production costs and improved reliability. Cost reductions, though directly accruing to project developers, should pass through to ratepayers as more favorable power purchase costs.

- Improved Performance: Some of the actions will facilitate improvements to power plant technical performance. For example, the cold-climate wind turbine pilot project is intended to lead to turbine design refinements enabling reliable operation in the severe climate of the Rocky Mountain Front. Like cost reductions, benefits of improved performance, though directly accruing to the resource developer, should pass through to ratepayers as reduced power costs and greater reliability.

Priority and Timing

Certain actions should be implemented immediately. These are indicated in the descriptions and schedules that follow. Current load growth conditions suggest that follow-on actions be implemented promptly as shown in the schedules, providing that the need for these actions is sustained by findings of preliminary actions. However, it is important that these schedules be periodically reassessed in light of improved resource information, changing technology and electrical load growth. Experience has shown that attempts to develop resources "before their time" may adversely affect the credibility of the resource.

Cost

Preliminary cost estimates are included in the descriptions of the actions. Precise cost estimates, however, will be possible only when a detailed statement of work for each action is completed. And, for some actions, a detailed statement of work only can be prepared upon completion of prerequisite actions. That is because the information obtained from the prerequisite actions defines the scope, design, or even the need for following actions. Preparation of detailed statements of work is best left to those responsible for implementation of each activity. Thus, the cost estimates provided in this chapter should be viewed as approximations to be refined as the confirmation agendas are implemented.

The most expensive actions will be the demonstration projects. Because these will be operational generating plants, they will be costly. And because the demonstration projects may be completed in advance of the resource being cost-effective, a premium over the then-current value of energy may be required to cover the costs and risks associated with first-time development. But, because these projects likely would be developed using output contracts,[1] ratepayers will pay only for successful projects, and then only when the projects enter service. Because a successful demonstration project will produce useful energy, the true cost of the demonstration projects will not be the full cost of the power purchase contracts, but the net of the payments for energy, less the then-current value of energy from new resources. The premium paid for a demonstration project constructed in advance of need should decline as loads grow and avoided costs for new resources rise. The net costs of these projects ultimately are expected to be captured through the reduced cost of follow-on resource development, including the resource options directly secured as a result of the demonstration projects.

The estimated annual cost for the recommended package of actions is shown in Table 16-1. The estimated annual cost of the first four years of the recommended program (the period prior to the first demonstration project coming into service) is estimated to range from about $1 million to $1.6 million. This would increase Bonneville's preference rates about one-tenth of one percent if all costs were borne by Bonneville and incorporated into Bonneville's preferred rates (neither of which is recommended). Rate impacts would increase once the recommended demonstration projects come into service, but even then are estimated to be about .5 percent.[2]

Implementation Issues

The RD&D Advisory Committee has concluded that mechanisms exist to allow accomplishment of the recommended actions. But the committee also has concluded that significant impediments remain to implementation of resource confirmation activities in the Northwest.

One problem is the sharing of costs and benefits. Most of the proposed actions are expected to benefit ratepayers regionwide, yet no mechanism exists to spread the costs of these actions equitably among the region's ratepayers. In previous power plans, the Council tended to look to Bonneville as the principal source of funding to support regional resource research, development and demonstration needs. Through its power sales agreements and the exchange program, Bonneville, more than any other single entity in the region, has the ability to spread resource confirmation costs to those who potentially benefit. But, it is clear that Bonneville will not be the sole entity acquiring new resources. Therefore, in the interest of equity, it is important to seek resource confirmation funding mechanisms that more broadly spread the costs of resource confirmation among those who potentially benefit.

1./ An output power sales contract is one in which the purchaser pays for the energy production of a project at an agreed-upon rate. Payments commence upon delivery of energy.

2./ Based on the estimated net costs of the demonstration projects (total cost less energy value).

Table 16-1
Estimated Annual Costs for Recommended Actions[a]
(thousands)

	Year 2	2	3	4	5	6	7
COM-01 Information[b]	50	50	50	50	50	50	50
GEO-01 Technical Monitoring[b]	25	15	15	15	15	15	15
GEO-02 Base-Line Data[c]	50	100	150	100	50	--	--
GEO-03 Conflict Ident.[b, c]	150	150	150	100	75	75	75
GEO-04 Demonstrations[b, c]	60	60	60	60	6,200 (1,900)	12,300[d] (3,700)	18,400[d] (5,500)
SOL-01 Resource Data[e]	125	125	75	75	75	75	75
SOL-02 Applications	75	--	--	--	--	--	--
SOL-03 Technical Monitoring[b]	--	25	25	25	25	25	25
SOL-04 Resolve Constraints	--	f	f	f	f	f	f
SOL-05 Photovoltaic Acquisition	g	g	g	g	g	g	g
OCN-01 Technical Review	--	--	--	15	--	--	--
WIN-01 Resource Data[b]	100	100	100	100	100	100	100
WIN-02 Technical Monitoring[b]	25	25	25	25	25	25	25
WIN-03 Area Feasibility	275	275	--	--	--	--	--
WIN-04 Area Characterization[h]	--	110	110	110	110	110	--
WIN-05 Development Plans[i]	--	100	100	j	j	j	j
WIN-06 Cold Pilot	--	100	500	900	250[k]	250[k]	250[k]
WIN-07 Demonstration	--	50	50	50	50	5,500[d] (1,800)	5,500[d] (1,800)
Total (Gross)	960	1,295	1,420	1,635	7,035	18,535	24,525
Total (Net)	960	1,295	1,420	1,635	2,735	6,235	7,925

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a Constant 1990 dollars.
b Partly or wholly in Bonneville's budget through Fiscal Year 1993.
c Assuming three resource areas staged at approximately annual intervals.
d Gross costs of power purchase with successful projects; net costs assuming new resource costs of 5 cents per kilowatt-hour are shown in parentheses.
e The costs shown assumed that five additional stations are established over the initial two-year period.
f The scope of SOL-04 will be established by findings of SOL-03.
g Because this resource only would be acquired when cost-effective, there would be no net "R&D" cost. Additional costs could be incurred, if any special assessments of equipment performance were undertaken.
h Assuming 15 wind resource areas.
i Assuming two wind resource areas.
j Continue for other wind resource areas, if successful.
k Special experiments may increase the annual operating cost.

One approach is for a lead utility to enter into joint contracts with other utilities for support of specific activities. Bonneville has proposed this approach for the geothermal demonstration program. But even joint contracting will spread cost imperfectly among the potentially benefitting ratepayers (unless all utilities participate, which is unlikely). Furthermore, soliciting joint participation is difficult and time consuming.

A second impediment is the limited ability of investor-owned utilities to recover costs associated with research, development and demonstration activities. Investor-owned utility expenditures either can be expensed or rolled into the utility's rate base. Expensed costs are immediately recovered through rates, but the utility earns no return on these expenditures. A utility may receive a return on expenditures incorporated into its rate base, but most states require the product of these expenditures to be "used and useful." Many of the recommended actions are not expected to result directly in a project meeting the conventional test of "used and useful." Oregon, for example, though allowing RD&D expenditures to be expensed, does not permit these expenditures to be rate-based.

The committee intends to address impediments to implementation of resource confirmation actions further and plans to prepare recommendations to the Council concerning this issue. But until these impediments are resolved, implementation of these actions and obtaining their expected benefits will require the concerted efforts of the Council, Bonneville, regional utilities, the state public utility commissions, resource developers and others.

Recommended Actions

The package of resource confirmation actions for each resource is described in this section. Each description includes a statement of the purpose and need for the action. This is followed by a description of the recommended action. This is not intended to constrain the design of the activity, but rather to serve as guidance and a benchmark for implementing the proposed action. Next are recommendations regarding the timing of the activity. Finally, an estimate of the cost of the activity is provided. Recommended schedules are shown in the accompanying figures.

The section begins with a general activity applicable to all four resources. The section then continues with geothermal, ocean, solar and wind resources, in that order.

General Actions

This action relates to all of the resources considered in this paper and can be undertaken as a single activity.

Resource Information Program (COM-01)

This action is intended to provide interested and affected individuals and organizations with timely and accurate information regarding geothermal, ocean, solar and wind resources. This should include information concerning technical developments and resource assessment and development activities in the Pacific Northwest and elsewhere. Better information regarding these resources should promote public and utility understanding and acceptance, facilitate resolution of environmental and other concerns, encourage the development of environmental and land use regulations that encourage quality development, and foster the development of these resources when needed. An objective of this effort is to provide current information to utilities engaged in the development of requests for resources to allow fair consideration of these resources in the resource acquisition process.

This action involves implementation of a renewable resource information program. This program should provide information about the current status and plans for resource exploration and development in the Pacific Northwest and the status of technology development. This information should be provided to utilities, developers, state and federal agencies, local governments, the environmental community and the public. Possible avenues include an information clearinghouse, periodic conferences and publications.

This action will draw upon information developed through the activities recommended for specific resources in the following sections. An important focus of this activity should be progress, findings and conclusions from implementation of the resource confirmation agendas described in this chapter.

This action should be implemented immediately and continued on an ongoing basis.

The annual cost of this program is estimated to be about $50,000.

Geothermal Confirmation Agenda

The regional geothermal potential may exceed 4,600 megawatts of energy,[3] at costs ranging from 4 to 9 cents per kilowatt-hour. Some of this potential likely could be obtained by development of basin and range geothermal resources, such as those that have been developed in California, Nevada and Utah. Because this type of resource has been demonstrated elsewhere, the Council considers 350 megawatts of geothermal energy from Northwest basin and range resource areas available for the resource portfolio of the Draft 1991 Power Plan.

The bulk of the regional geothermal potential would be from the Cascade geologic province. But the feasibility of developing Cascade geothermal resources has not been demonstrated. For this reason, the principal focus of this geothermal

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3./ An average megawatt is the amount of energy produced by one megawatt of capacity operating over a period of one year. This is equivalent to 8.76 gigawatt-hours.

agenda is to resolve the uncertainties associated with development of the geothermal resources of the Cascades.

The geothermal confirmation agenda consists of the following activities:

- Monitor geothermal technology and resource development.
- Assemble environmental base-line data.
- Identify environmental and land use conflicts.
- Initiate geothermal resource demonstration projects.

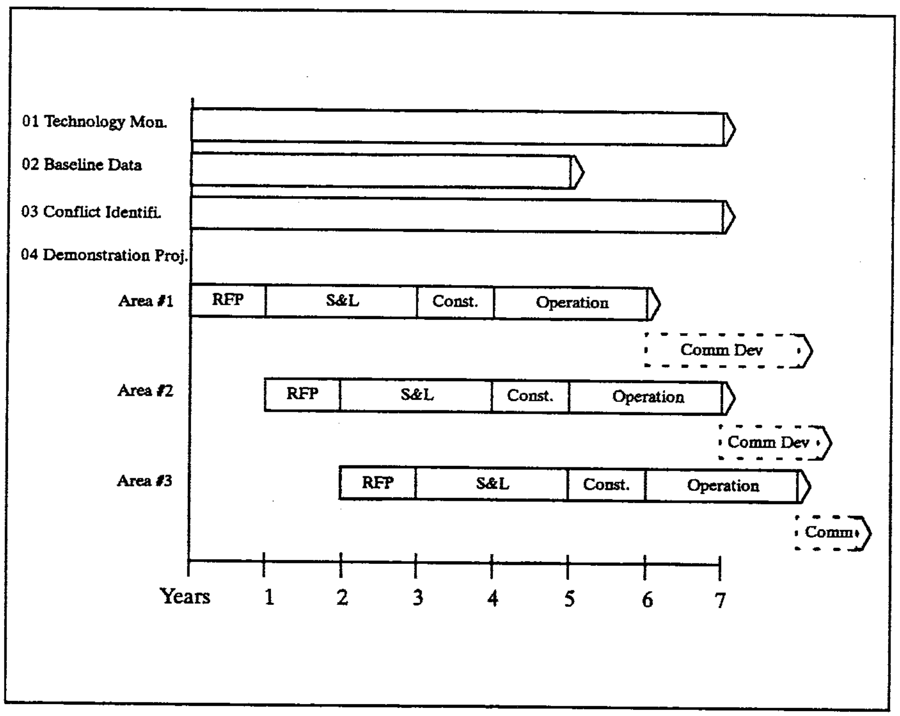
These activities are described below. The recommended schedule for these activities is shown in Figure 16-1.

Monitor Geothermal Technology and Resource Development (GEO-01)

The purpose of this action is to provide reliable data on geothermal power plant operating experience and geothermal resources to the power planning community and others. This will assist in making better estimates of the cost and performance characteristics of geothermal power plants. This task will provide information to support activity COM-01 (Resource Information Program) and parallels similar technology monitoring tasks recommended for ocean (OCN-01), solar (SOL-02) and wind (WIN-02).

Geothermal Agenda

Figure 16-1
Geothermal Confirmation Agenda



This action will involve creation and maintenance of a database containing geothermal resource and power plant data for active North American sites. Data would include operating experience, as well as available construction, cost, engineering, financing, power sales and regulatory information. This work will build on the "Four-State" geothermal inventory and assessment conducted by Bonneville.[4]

The estimated cost is about $25,000 for the first year and about $15,000 per year to maintain.

Assemble Environmental Base-Line Data (GEO-02)

The purpose of this action is to document the predevelopment environmental characteristics of geothermal resource areas. This will assist in identifying key environmental issues and to facilitate the National Environmental Policy Act (NEPA) process and other environmental assessment work. Present federal regulations require geothermal developers to collect one year of base line environmental data before beginning power plant construction. Federal agencies are required to complete a NEPA process prior to issuing permits for site development or to purchasing or wheeling the output of a geothermal project.

More reliable estimates of the environmental impacts of geothermal power plants can be made if longer-term data are available. Moreover, the existence of base line data prior to plant design and permitting is expected to shorten the lead time for development by reducing the time required to complete NEPA and other environmental assessment work required for licenses and permits for site exploration and development. The region's most promising geothermal resource areas are sufficiently well-defined that data acceptable for the NEPA process can be obtained. Base-line studies also may help avoid duplication of efforts by multiple developers operating within a single resource area, and may facilitate the assessment of cumulative impacts of geothermal development.

This action will involve documentation of pre-development environmental conditions for promising geothermal resource areas. Information to be collected may include data on air quality, climatology, geology, geochemistry, geophysics, hydrology, water quality, flora, fauna and cultural features. Work should proceed to the development of needed NEPA assessment documents. One approach might be to develop a general environmental impact statement for a resource area. Subsequent environmental impact statements for specific developments within the resource area could be "tiered off" the basic environmental impact statement, reducing the lead time required for completion of the environmental assessments for specific projects within the geothermal resource area.

The program initially should be established at the resource areas at which the demonstration projects (GEO-04) likely will be located. Two to three years typically will be required to collect and analyze data and to complete a general environmental impact statement for a resource area.

4./ Evaluation and Ranking of Geothermal Resources for Electrical Generation and Electrical Offset in Idaho, Montana, Oregon and Washington, 1985.

This action is expected to cost about $50,000 per year, per resource area.

Environmental and Land Use Conflict Identification (GEO-03)

The purpose of this action is to identify and facilitate resolution of potential environmental and land use conflicts at promising geothermal resource areas. Most promising geothermal resource areas in the Northwest are located near national parks, wilderness areas and other lands of high environmental quality, sensitivity and recreational value. Poorly conceived geothermal development near these areas may lead to land use and environmental conflict, inhibiting geothermal development not only at these, but at other resource areas. Already, controversies have developed from geothermal exploration near Crater Lake, Newberry Caldera and the Alvord Desert.

It is clear that the development of certain geothermal resource areas must be limited because of land use and environmental sensitivities. Advance identification of the potential for conflict and the development of possible remedial actions should reduce conflict, litigation and delay when development is proposed, thereby reducing resource lead times and minimizing expenditures on projects that are not acceptable for environmental or land use reasons.

This action seeks to identify key environmental and land use issues, and to initiate resolution of potential conflicts through land use and environmental management procedures. These might include comprehensive land use plans, zoning, site development and performance standards and state siting council regulations. This action will require the mutual efforts of state and local governments, resource management agencies, geothermal developers, environmental organizations, land owners and other interested and affected organizations and citizens.

This action will draw upon the inventories of natural and cultural values assembled in action GEO-02. An assessment of the likely effects of geothermal exploration and development, including transmission line and access road construction should follow. The compatibility of geothermal development with site conditions then should be assessed. Public participation should be sought in order to establish the value of the natural and cultural features (including geothermal potential) of the resource area. The action should conclude with the identification of possible mitigation measures. These might include siting and performance standards, comprehensive land use plans and other means.

Bonneville is supporting activities intended to accomplish the objectives of this action at geothermal resource areas on the Deschutes National Forest. At a minimum, these activities should be expanded to include all geothermal resource areas where geothermal demonstration projects will be sited.

This action is expected to cost $50,000 to $100,000 per year for each resource area. Several years might be required to complete this work at each resource area.

Geothermal Resource Confirmation Program (GEO-04)

The purpose of this action is to demonstrate the feasibility of electric power generation using Northwest geothermal resources. Each major geothermal resource area of the Cascades is thought to have the potential to generate several hundred megawatts of energy or more. But each area is thought to have somewhat unique characteristics, and none is understood well enough to predict with confidence the feasibility or costs of development. Nor is it fully understood what technology and environmental control measures may be required to develop the resource in a cost-effective and environmentally acceptable manner.

A series of geothermal demonstration projects located at promising resource areas can produce many important benefits. A demonstration project can confirm the cost and feasibility (or lack thereof) of using the geothermal resources of a particular resource area to generate electric power. Demonstration projects also can accelerate the refinement of geothermal technology to suit specific resource characteristics, identify and test environmental mitigation measures, provide a basis upon which to judge environmental and land use concerns, and reduce investment risk and cost of commercial-scale development that might follow. A demonstration project also can be used as a vehicle to confirm the presence of additional resource potential. All this can provide improved planning certainty and shorten the lead time for follow-on commercial-scale development.

The elements of this demonstration program should include exploration at multiple resource areas, demonstration of generating plant operation, and confirmation of additional resources for future development. Demonstration of innovative technology, while not discouraged, should be secondary to successful plant operation. The focus of the program should be Cascades-type geothermal resources, though other types of resources should not be ruled out.

Bonneville has indicated a willingness to join regional utilities to purchase up to 10 average megawatts of output from each of three geothermal projects.[5] Right of first refusal on up to 100 megawatts of additional development on each property would be required. An output power sales contract would be used, so payments would be made only as power was delivered.

Action to secure one demonstration project should begin immediately. Action to secure demonstration projects at two additional resource areas should follow at one-year intervals, or more quickly. It is expected that at least four years will be required from preparation of a request for proposals to an operating demonstration project (see Figure 16-1).

Energy costs of a demonstration plant may range from 6 to 8 cents per kilowatt-hour, and possibly higher. These costs likely will be higher than the marginal cost of new resources during the early years of demonstration plant operation. But the premium will decline as the marginal cost of new resources increases over time. Bonneville has agreed to contribute to a demonstration project

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5./ The individual project size could exceed 10 average megawatts, with Bonneville taking up to 10 megawatts of output. This would provide flexibility to capture the potential cost savings from larger-scale projects.

if other utilities are willing to join in the financing. Costs could be recovered over the operating life of the demonstration plant.

Ocean Power Agenda

The Council has concluded that ocean power technologies eventually may provide several hundred average megawatts of energy to the Pacific Northwest. The most promising of Northwest oceanic energy resources appears to be ocean wave energy. But ocean power technologies are at an early stage of development. Much additional technological research, development and demonstration must occur before ocean power resources can be considered sufficiently reliable and cost-effective to be included in the Council's plan. Moreover, there will be significant environmental constraints to large-scale deployment of wave and other ocean energy devices.

The Council requested that its Research, Development and Demonstration Advisory Committee prepare recommendations for furthering the development of ocean energy resources. In view of the early state of development of ocean energy technologies and the apparently limited applications of these technologies in the Pacific Northwest, the committee recommended that resource confirmation efforts for the next several years be focused on other resources thought to be available in greater quantity and at lower cost. Accordingly, ocean energy action is limited to periodic review of technological development.

Periodic Review of Ocean Power Technology (OCN-01)

The purpose of this action is to monitor the development of promising ocean power technologies. Information concerning the development of these technologies will allow the region to identify the need for further action that might be undertaken later, such as resource assessment and demonstration projects. This task will provide information to support activity COM-01 (Resource Information Program), and parallels technology monitoring tasks recommended for geothermal (GEO-01), solar (SOL-03) and wind (WIN-02).

This action would involve preparation of a periodic assessment of the status of ocean power technologies, emphasizing the technologies with greatest promise to the Northwest. The Council's recent assessment suggests that wave energy devices have the greatest potential in the Pacific Northwest. Biomass conversion, salinity gradient and current turbines may offer some potential in the long term. Tidal-hydroelectric and ocean thermal conversion devices appear to offer little potential in the Northwest because of resource limitations.

The cost of this action is estimated to be about $10,000 to $15,000. The Committee recommends that the next review of ocean power technology status be conducted in conjunction with the next general revision of the Northwest Power Plan. One approach to this review would be to encourage EPRI to produce periodic updates of its 1987 assessment of the state-of-the-art of ocean energy technologies (EPRI AP-4921).

Solar Power Confirmation Agenda

The committee believes that solar photovoltaics, in particular, offer good potential for future application in the Northwest. But because of currently high cost the deployment of these and other solar technologies will follow that of geothermal and wind resources in the Northwest, except for certain remote applications of photovoltaics that currently are cost-effective. Accordingly, the committee placed somewhat less emphasis on solar compared to geothermal and wind. Nevertheless, the recommended solar actions are expected to form the foundation for a broader solar confirmation effort as the costs of solar technologies decline and feasible applications broaden.

The committee's solar recommendations include collection of long-term solar insolation data to support deployment of solar-electric technologies when these become cost-effective, monitoring of solar-electric technology development, and a feasibility study of possible Northwest applications of solar photovoltaics. A follow-on contingent action would address constraints to deployment of photovoltaic technologies. The Council, in considering these recommendations, added a fifth activity, consisting of a program to seek out and acquire all cost-effective applications of solar photovoltaics. The sequencing of these actions is illustrated in Figure 16-2.

Long-term Solar Insolation Data Collection (SOL-01)

The purpose of this activity is to assemble improved regional solar insolation data. Better insolation data, including finer spatial resolution, information on both global and direct-beam radiation, and longer-term records, will support the design and analysis of solar applications, provide better understanding of the future contribution of solar-electric power, and help identify sites for future solar-electric installations.

This action will involve re-establishing a comprehensive regional solar insolation monitoring system, insolation data collection and data reduction. The monitoring system should consist of about 10 monitoring stations at locations suitable for creating improved regionwide maps of solar insolation. Each station should collect insolation and other data required to assess the performance of various types of solar-electric and direct-use applications, including global, fixed-beam and tracking-beam radiation measurements. The monitoring system should be designed to operate for a period of at least 15 years in order to gain a good understanding of interannual variation and possible long-term trends. This effort should build upon current and earlier insolation monitoring efforts. These include the networks maintained by the Eugene Water and Electric Board, the irrigation scheduling network operated by the Washington State Energy Office, and the earlier insolation monitoring program sponsored by Bonneville.

This action should be implemented immediately to minimize gaps in solar data records. Data should be collected, reduced and reported on a continuing basis.

Solar Agenda

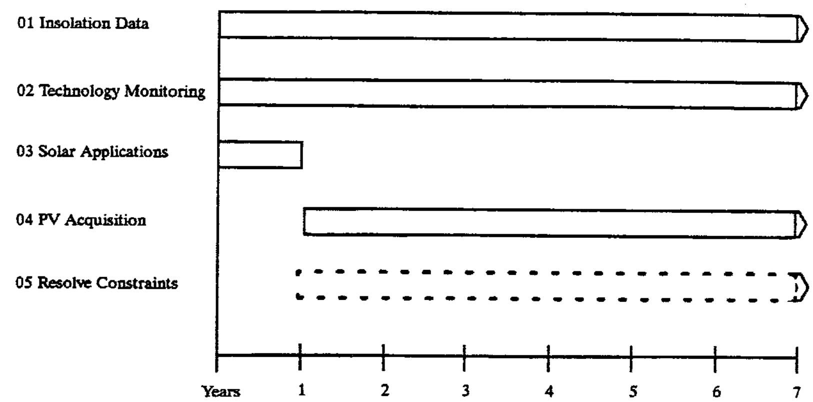


Figure 16–2
Solar Confirmation Agenda

This action is estimated to cost about $20,000 for setting up each new monitoring station and about $50,000 to $100,000 annually for station maintenance data collection, reduction and reporting.

Monitor Solar-Electric Technology Development and Application (SOL-02)

The purpose of this action is to provide reliable information on solar-electric technology and its application to the power planning community and others. This should assist in early identification of promising Northwest applications of solar-electric technologies and in making better estimates of the cost and performance characteristics of solar technologies. This task parallels similar technology monitoring tasks recommended for geothermal (GEO-01), ocean (OCN-01) and wind (WIN-02).

This action will involve creation and maintenance of a database of solar photovoltaic and solar-thermal technology. Data should include operating experience as well as available construction, cost, engineering, financing, power sales and regulatory information. This work should incorporate information assembled in activity SOL-02. To the extent feasible, this effort should rely upon data assembled by organizations such as EPRI and the Solar Energy Research Institute (SERI).

This activity should commence immediately and continue on an ongoing basis.

The estimated cost is about $25,000 per year.

Assess Regional Applications of Solar Photovoltaic Technology (SOL-03)

The purpose of this action is to identify promising applications of photovoltaic technologies in the Pacific Northwest and key constraints to these applications. Because of good prospects for cost reductions and a wide diversity of potential applications, the committee believes that it is important to gain an understanding of potential solar photovoltaic applications in the Pacific Northwest. This will allow the region to focus on the technologies and applications showing the greatest promise for this region.

This action will consist of a "paper study" of promising photovoltaic applications in the Northwest. The study should include central-station generation as well as distributed applications, currently available photovoltaic technologies as well as those promising to become available in the next several years, and retrofit as well as "greenfield" applications. The study should identify and describe possible applications and assess their technical feasibility, cost and likely timing. Key constraints to these applications should be identified and possible means of overcoming these constraints proposed. The results of this study will provide information needed for acquisition of cost-effective photovoltaic applications (SOL-05).

This action should be implemented immediately. Approximately one year will be required to complete this work.

This action is estimated to cost about $75,000.

Resolve Constraints to Regional Photovoltaic Applications (SOL-04)

The purpose of this action is to resolve constraints to promising regional applications of photovoltaic technology. The need for and timing of this task will be conditioned on the findings of the assessment of regional applications of solar photovoltaic technology (SOL-03). This effort will consist of actions to resolve the constraints identified in action SOL-02.[6]

6./ If the findings of SOL-03 suggest the closer monitoring of photovoltaic technologies is needed, or that a demonstration project is desirable, these objectives might be accomplished by active participation in PVUSA (Photovoltaics for Utility-Scale Applications). PVUSA is a national program for testing and comparing emerging photovoltaic technologies initiated by Pacific Gas and Electric Company, and jointly supported by the U.S. Department of Energy, Electric Power Research Institute (EPRI), the California Energy Commission and additional utilities and state agencies. Under way for nearly four years, PVUSA sponsors small-scale (20-kilowatt) demonstrations of emerging solar photovoltaic technologies, and larger (200 to 400 kilowatt) demonstrations of promising technologies.

Bonneville and other members of the Electric Power Research Institute have access to information derived from PVUSA activities through EPRI's
(Footnote 6 Continued on Next Page)

Acquire Cost-Effective Solar Photovoltaic Applications (SOL-05)[7]

The purpose of this action is to improve understanding of the cost and performance of photovoltaic technology in the Northwest, strengthen the market for photovoltaic devices and facilitate a modest expansion of environmentally benign generation for meeting Northwest electrical loads.

Although the cost of electricity from central-station photovoltaic plants is still much greater than from other resources, there are specialized applications for which photovoltaic power sources may be cost-effective. These applications generally are characterized by remote location and low power demand--characteristics that increase the unit energy cost of providing electrical service. Typical cost-effective applications of photovoltaic technology include communication relay stations, maritime navigation aids, railroad signals, pipeline cathodic protection and remote household service.

As efficiencies increase and costs decline, new markets will open to photovoltaic devices. In the United States, this market is expected to include irrigation pumping and household loads requiring line extensions of one to two miles. Further efficiency improvements and cost reductions eventually may open up the central-station bulk power market.

Although apparently there has been considerable penetration of the remote power market by photovoltaics, this market has developed largely through non-utility efforts. And although the cost of grid extension and average retail power costs routinely are considered by those considering photovoltaic systems, it is unlikely that the marginal cost of new resources normally is incorporated in this decision-making process. This action item should foster a greater awareness of possible photovoltaic opportunities and, possibly, design, financial and equipment supply and service advantages.

This action will involve the design, testing and eventual implementation of programs for the acquisition of cost-effective photovoltaic devices. These programs should include methods of assessing the cost-effectiveness of photovoltaic devices compared to conventional grid service. The marginal cost of new grid-service resources should be considered in these assessments. Other services that might be included in these programs include design and financial assistance, standard photovoltaic equipment packages (including back-up power sources, where necessary)

(Footnote 6 Continued from Previous Page)
participation in PVUSA. Two levels of more active participation in PVUSA are available. Technical review committee membership is available for $25,000 per year. This level of membership provides information on photovoltaic technologies and demonstration project findings. Steering Committee membership is available for $50,000 per year. This level of membership enables the participant to be involved in decisions regarding the nature and location of demonstration projects. Steering committee membership could lead to demonstration project cost-sharing.

7./ This activity did not come from the RD&D Advisory Committee, but was added by the Council after considering other comments and reviewing the RD&D recommendations.

and equipment service. These programs should be made available regionwide, although priority might be given to areas where solar resources and local load characteristics favor photovoltaic applications.

This action should follow the photovoltaic feasibility study (SOL-03). That study will identify potentially cost-effective photovoltaic applications, thereby providing a basis for designing the acquisition policies and procedures needed for this action.

Because this activity would secure only cost-effective photovoltaic applications, it should be accomplished at no net cost to the power system.

Wind Power Confirmation Agenda

The regional wind power potential is estimated to be nearly 18,900 megawatts of turbine capacity. This could supply approximately 4,500 average megawatts of energy at costs ranging from 7.5 to 15 cents per kilowatt-hour. But nearly 85 percent of this potential lies along the eastern slopes of the Rocky Mountains in Montana. Successful development of this resource requires resolution of transmission constraints, institutional questions and the ability of wind turbines to operate reliably in the often-harsh environmental conditions of central Montana.

Although it is believed that contemporary wind turbines are capable of reliable operation at milder climate sites in the western part of the region, uncertainties remain regarding these resources. Chief among these are the spatial extent, wind turbulence and shear characteristics of promising resource areas, and site-specific technical, environmental and institutional constraints to development.

Considering these constraints to development, the Council concluded that 400 annual average megawatts of electricity could be obtained by development of wind resources over the 20-year planning period of this power plan. Because of limited wind resource data, harsh environmental conditions and general remoteness of the Rocky Mountain Front wind resource areas, the Council currently considers very little of the potential of these areas to be available for the Draft 1991 Power Plan's resource portfolio. Wind-generated electricity considered for the portfolio is expected to be available at costs ranging from 7.5 to 13 cents per kilowatt-hour. Further reductions in the cost of wind-generated electricity are expected. The Council also concluded that the potential exists for more extensive development of the Northwest wind resource, particularly along the eastern front of the Rocky Mountains in Montana.

The wind power confirmation agenda has two principal thrusts. One is to prepare for commercial development of the wind resources of the western part of the region. The Committee believes that this can be accomplished by improved characterization of wind resource areas found to hold the greatest promise for development, and the identification and resolution of key issues affecting development.

The second thrust is to confirm the feasibility of developing the Montana wind resource. This will require an assessment of transmission requirements. If it is found feasible to transmit power from these areas to the regional grid, this effort should continue with improved wind resource area characterization, identification and resolution of key issues affecting development and the development and demonstration of wind turbine generators with year-round dependability under Montana climatic conditions. The level of investment in each of these activities should be proportional to the likely extent of a potentially cost-effective resource.

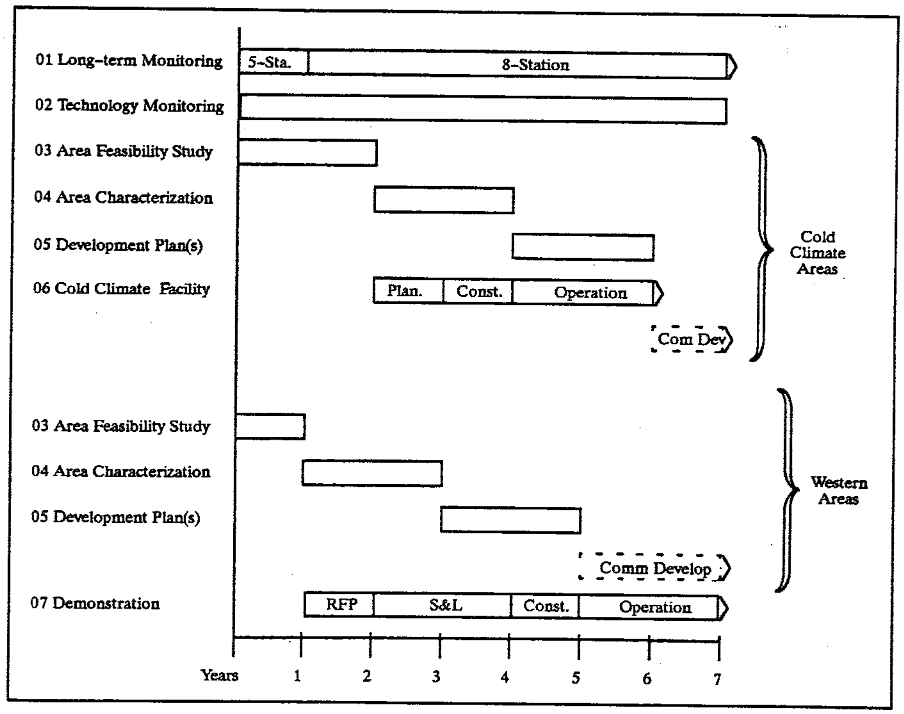
Continuing elements of the wind power confirmation agenda are maintenance of a regional long-term wind monitoring network and monitoring of wind technology development.

The Council, in considering the committee's recommendations, added an activity: development of a commercial-scale wind demonstration project. Benefits of this project include confirmation of estimated wind project costs and performance, experience integrating wind farm electrical output with the grid, better understanding of the physical and environmental consequences of wind farm construction and testing of wind farm siting and licensing procedures.

These activities are described further below. A schedule for these activities is shown in Figure 16-3.

Wind Agenda

Figure 16-3
Wind Confirmation Agenda



Long-Term Wind Resource Data Collection (WIN-01)

The purpose of this action is to monitor long-term (interannual) variation in regional wind resources. Wind resources are subject to variations over periods of many years that can only be understood through long-term measurements.

Knowledge about interannual variation will reduce project risk, enhance the quality of energy production estimates and facilitate resolution of questions regarding interaction of large-scale wind power development with the regional electric power system.

This action will involve maintaining the five existing long-term wind monitoring stations. Three new long-term stations should be considered for addition to the regional network once a wind resource area development feasibility study (WIN-03) is completed. Wind statistics from these stations should be compiled on an ongoing basis. The three new stations should be sited in areas that would contribute to the complete coverage of the Northwest's promising wind resources.

In 1988, there were 10 long-term stations in operation in the region. These stations were sited to serve as the long-term base-line stations against which other shorter-term measurements could be compared. As originally designed, this program was to last five years. By the end of 1989, five of the original 10 stations had been dismantled, having served their five years. But it is now known that five years is not sufficient to capture the full range of interannual variation. Additional stations may be dismantled if the goals of this program are not revised to support continued long-term monitoring of wind resources.

This action should be implemented immediately and continue on an ongoing basis. The five existing stations should continue to operate, and analysis of their measurements should be enhanced. Establishment of the three new sites would be conditioned upon the findings of action WIN-03.

The cost of maintaining the current network of five stations is about $60,000 per year. An expanded network of eight stations is estimated to cost about $100,000 per year.

Monitor Wind Power Technology and Resource Development (WIN-02)

The purpose of this action is to provide reliable information on wind power technology and wind resource development to the power planning community and others. This would assist in improving estimates of the cost and performance characteristics of wind power development. This activity parallels similar monitoring tasks for geothermal (GEO-01), ocean (OCN-01) and solar (SOL-03) resources.

This action would involve creation and maintenance of a wind power database. Information to be collected would include operating experience as well as available construction, cost, engineering, financing, power sales and regulatory information. This task should seek out information regarding wind power development in California and elsewhere, and improvements in wind power technology. To the extent feasible, this effort should rely upon data assembled by organizations such as EPRI, SERI and Sandia National Laboratory.

This activity should continue on an ongoing basis.

The estimated cost is about $25,000 per year.

Assess the Feasibility of Developing Promising Pacific Northwest Wind Resource Areas (WIN-03)

The purpose of this action is to identify wind resource areas having the greatest promise for development by eliminating areas with "fatal flaws." This review will allow better definition of the institutional, environmental, and technical feasibility of developing the Northwest's best wind resource areas, and will guide follow-on actions including spatial, turbulence and shear measurements (WIN-04), preparation of wind resource area development plans (WIN-05) and a cold-climate turbine test facility (WIN-06).

The action will consist of an evaluation of the feasibility of developing each of the promising wind resource areas identified in the Bonneville wind energy assessment program, plus other promising wind resource areas such as those identified by the Montana Department of Natural Resources and Conservation. Two tasks, a screening followed by a site ranking, are suggested. Priority in the screening should be given to technical, environmental and institutional "showstoppers." Resource areas for which development appears to be feasible then would be ranked, considering factors such as cost-effectiveness, expected energy production, available and potential transmission capacity, environmental impacts, and seasonality (including possible synergistic effects of areas having different seasonal energy production profiles).

An important component of this action is assessment of transmission interconnection requirements for large-scale development of Rocky Mountain Front wind resources.

This action should begin immediately. It is estimated it will take one year to complete this work for areas in the western part of the region. Two years may be required to complete this study for Montana areas because of the greater complexity of the transmission interconnection assessment.

The cost of this action is estimated to be about $550,000, including $250,000 for the analysis of transmission interconnection of Rocky Mountain Front wind resource areas.

Measure Quantity and Quality of the Better Wind Resource Areas (WIN-04)

The purpose of this action is to obtain better information about the quantity and quality of wind resources at resource areas showing the greatest promise for development. The wind resource areas for which this action should be implemented will be identified in action WIN-03. This action is expected to define developable land area more completely, and thereby allow better estimates to be made of the energy potential and boundaries of prospective wind resource developments. The results will establish a better empirical foundation for estimating the quantity and quality of the Northwest's wind resources, reducing the uncertainty currently associated with this resource. This action will provide supporting data for preparation of wind resource area development plans (WIN-05) and ultimately for commercial wind power development. The information developed by this action should reduce development risk and may reduce site development lead time by one to two years. Finally, this action should provide better information about the boundaries of the resource areas for agencies and others responsible for permits and siting standards.

This action will measure the spatial extent, shear and turbulence characteristics of the Northwest's most promising wind resource areas, as identified in action WIN-03. This work will build upon the wind resource information collected in the Bonneville regional wind resource assessment. The objective is to collect that data that would allow better estimates to be made of the potential productivity of wind resource areas, and to provide a database sufficient to allow a wind resource developer to begin micrositing studies immediately. However, it is not intended that this work address micrositing. That task is machine-specific and best accomplished by the resource developer.

The energy production potential of a wind resource area is directly related to the size of that area. The boundaries are sensitive to the relation between the wind and the topography. These factors determine how many wind turbines can be installed. Though the Bonneville regional wind power assessment includes estimates of the spatial extent of promising wind resource areas, these estimates are based on very limited information--a single meteorological tower in most cases. The spatial extent of these areas was estimated by inspection of topographic maps and indicators such as flagged vegetation.

An understanding of wind shear and turbulence is a prerequisite to developing a wind resource area. Small errors in site assessment can lead to large errors in estimating wind farm energy production. Rolling terrain is problematic due to spatial variations in the wind caused by topography. The extrapolation of wind data from the heights where measured to the prospective turbines is done with wind shear factors. An understanding of wind shear (the increase in wind speed with height) is therefore important. Excessively turbulent winds will result in poor wind turbine performance, high maintenance costs and equipment failure.

This task should commence following completion of action WIN-03. A minimum of a year of data collection is estimated to be required for an assessment of the spatial extent at each wind resource area. Measurements of shear and turbulence would be done simultaneously. The complete assessment package, including analysis and reporting, is estimated to require two years for a typical area of moderate size. The number of areas to be assessed depend on the outcome of the area feasibility study (WIN-03). Several areas could be done at once. If WIN-03 suggests that large-scale development of the Rocky Mountain Front is feasible, a substantial portion of this effort should be focused on that resource.

The cost of this action will depend on the number of wind resource areas to be assessed and the size of the selected areas. The committee's Wind Resource Advisory Panel estimated that spatial, shear and turbulence studies could be completed at 15 wind resource areas, including the very large Blackfoot area on the eastern slope of the Rocky Mountains, for a minimum cost of $550,000.

Wind Resource Area Development Plans (WIN-05)

The purpose of this action is to resolve major technical, environmental and institutional uncertainties at important wind resource areas. Area development plans can help achieve best resource use with minimum environmental impact, and can reduce planning uncertainty, site development lead times and project investment risk. This work also can contribute to cost savings and improved performance for later commercial-scale development. This action will be accomplished by identifying and resolving area technical, environmental and institutional development issues, as also recommended for geothermal resource areas (GEO-03). If successful, similar plans might be developed for additional wind resource areas as these become cost-effective to develop. The need for and scope of this action will be determined by the findings of the area feasibility study (WIN-03) and the spatial, shear and turbulence studies (WIN-04).

The action will involve preparation of wind resource development plans for two wind resource areas. If the feasibility of large-scale development of the Rocky Mountain Front wind resource areas in Montana is demonstrated in prerequisite actions WIN-03 and WIN-04, at least one development plan should be for a Rocky Mountain Front wind resource area. These plans should focus on the technical, environmental and institutional site development issues identified in the feasibility study (WIN-03). These plans would not design actual projects. That level of design is best addressed by resource developers. Instead, the area development plans would address the overall technical, environmental and institutional constraints to development. One objective, for example, would be to establish local siting and licensing procedures. Also, in cooperation with the local utility, existing model wind farm interconnection requirements could be adapted to the requirements of the area. An important component of the development plans would be preparation of grid interconnection plans.

This action should commence upon completion of action WIN-04. Plans for a western resource area could be completed in one year. Plans for a Rocky Mountain Front area are estimated to require two years because of the greater complexity of the constraints facing wind power development in this area.

The cost of two area development plans is estimated to be $200,000.

Cold-Climate Wind Turbine Pilot Facility (WIN-06)

The purpose of this action is to develop and demonstrate wind turbines capable of reliable year-round operation in the environment of the Rocky Mountain Front. Development of this facility would proceed if large-scale development of the wind resources of the Rocky Mountain Front were found to be feasible (Action WIN-03). This action should occur in parallel to actions WIN-04 and WIN-05. Successful completion of these actions should open the way for large-scale commercial development of the wind resources of Montana's Rocky Mountain Front, when needed and cost-effective.

Most wind turbine generator operating experience has been in California. Though wintertime sub-freezing conditions are experienced at some of California's wind resource areas, the environment of these areas is not as challenging as the wintertime high wind and sub-zero cold conditions characteristic of the Rocky Mountain Front wind resource areas. Moreover, adverse climatic conditions occur in Montana when wind resource potential and regional electrical loads are at their greatest. In contrast, freezing conditions occur in California during slack load periods.

Large-scale deployment of wind turbines in Rocky Mountain Front wind resource areas will require the development and testing of turbines capable of sustained, reliable operation in the environment of these areas. In particular, the challenges of extreme cold, extreme winds and limited maintenance opportunities need to be addressed. Turbine manufacturers believe, however, that existing state-of-the-art machines can be modified to operate reliably under these conditions.

This action would involve creation of a cold-climate wind turbine pilot facility. This facility should be located at a site having wind and climate conditions representative of the better wind resource areas of the Rocky Mountain Front. The facility should be stocked with several wind turbine designs, adapted for cold-climate conditions. The site and machines should be provided with instrumentation to support testing. The site should be conveniently located to centers of activity to ensure adequate maintenance and monitoring. The principal objectives of the pilot facility should be to refine and test wind turbine technology for cold-climate conditions, to develop operation and maintenance procedures suitable for cold-climate conditions and to prepare better estimates of the capital and operating costs of turbines located in cold-climate areas.

Planning for the cold-climate test facility should commence if action WIN-03 indicated the feasibility of large-scale development of the Rocky Mountain resource. Planning and construction of the facility is estimated to require about four years. At least two years of pilot facility operation is desirable prior to commercial-scale deployment of turbines on the Rocky Mountain Front.

The overall construction cost of a cold-climate wind turbine pilot facility including about five 100 to 300 kilowatt machines is estimated to cost $1 million to $2 million. Annual operating costs, including basic data logging, are estimated to be about $250,000, exclusive of the costs of specific experiments. For example, a comprehensive structural measurement program operated by the Solar Energy Research institute on two turbines at San Gorgonio cost $600,000, not including data reduction and analysis costs. Because of interest elsewhere in developing cold-climate wind turbine capability, there appears to be a good chance of securing joint participation in this facility. Opportunities for cost-sharing with U.S. Department of Energy, turbine manufacturers, and other states, Canada, other countries, regions and utilities having cold-climate wind resources should be explored.

Regional Wind Farm Demonstration Project (WIN-07)[8]

This action will demonstrate a state-of-the-art commercial wind project in the Northwest. This is expected to confirm the cost and performance of wind power plants under Northwest conditions, provide experience in integrating the output of a commercial-scale wind farm with the regional power system, improve understanding of the physical and environmental consequences of wind power development and test wind power siting and licensing procedures. This project also will provide a test area for research and will refine wind farm operational and maintenance procedures for Northwest conditions.

8./ This activity did not come from the RD&D Advisory Committee, but was added by the Council after considering other comments and reviewing the RD&D recommendations.

The knowledge gained from this project should lead to greater local confidence in wind power technology, more competition among developers, shorter lead times and improved performance from subsequently developed commercial wind farms. The cost and performance information from this project is expected to reduce resource planning uncertainty.

The action would involve the development of a commercial demonstration wind farm of about 30 megawatts capacity. A project of this size, sited in a good wind resource area, should produce from 6 to 11 average megawatts of energy. A site that represents the better Northwest wind resource areas should be chosen for the demonstration project. The project should employ commercial-grade turbines of proven reliability. A 30-megawatt array would be of sufficient size to allow economies of scale in its development and operation and, therefore, demonstrate representative energy costs. This size also should be sufficient to test system integration equipment and procedures.

The power purchase price offered to developers for this project should be capped by the estimated cost of the geothermal demonstration projects (GEO-04), or expected marginal resource costs, whichever is greater. An output power sales contract should be used to provide incentive to the developer and to minimize risk to the region. The contract should allow for research to be performed at the site and should make detailed operational data available.

The total cost of the project to the regional power system might range from $4 million to $7 million per year, depending on wind farm performance and cost. Funding to support specific research would be additional. The premium over then-current marginal resource costs would depend on marginal resource costs at the time that the project operates. If marginal resource costs were 5 cents per kilowatt-hour, for example, when the project enters service, the net cost of the project would be about $1.3 million to $2.3 million per year.

A power purchase offer for this project should be extended as soon as the likely cost of the geothermal demonstration projects can be established. The offer should remain outstanding until accepted. Siting, licensing and development of the project would require about three years to accomplish.

APPENDIX 16-A

MEMBERS OF THE NORTHWEST POWER PLANNING COUNCIL RESEARCH, DEVELOPMENT AND DEMONSTRATION ADVISORY COMMITTEE

MEMBERS OF THE NORTHWEST POWER PLANNING COUNCIL RESEARCH, DEVELOPMENT AND DEMONSTRATION ADVISORY COMMITTEE

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Yacov Shamash, Washington State University
Robert Stokes, Solar Energy Research Institute
Brian Thomas, Puget Sound Power and Light Company
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APPENDIX 16-B

MEMBERS OF THE NORTHWEST POWER PLANNING COUNCIL RESOURCE TECHNICAL ADVISORY PANELS

MEMBERS OF THE
NORTHWEST POWER PLANNING COUNCIL
RESOURCE TECHNICAL ADVISORY PANELS

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Robert Edminston, Anadarko
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