1991 NORTHWEST CONSERVATION and ELECTRIC POWER PLAN

VOLUME II—PART II

NORTHWEST POWER PLANNING COUNCIL

91–05

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CHAPTER 8

GENERATING RESOURCES

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 Activities 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 commonly 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, among generating resources, 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 resource, like 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.

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, as well as a greater focus on these resources, the assessments of cogeneration, biomass, geothermal, ocean, solar and wind resources appearing in this plan are much more detailed than those appearing in previous power plans.

A second area of significant effort is the assessment of new coal resources. Although 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 representative pulverized coal-fired 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. Moreover, because of environmental concerns regarding use of coal, this plan assumes use of coal gasification-combined cycle power plants in lieu of the pulverized coal-fired power plants used in previous plans. Although other types of coal technologies may prove to be the "cleanest" at the time the decision to construct a coal plant might be needed, coal gasification plants are viewed by the Council as the best currently available technology for generating power from coal. In addition to providing reduced emissions, coal gasification plants provide fuel switching flexibility, the ability to phase construction, shorter construction lead times, increased fuel use efficiency and reduced water consumption.

Less effort has been directed to reassessing new hydropower resources, 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

"Reference" levelized energy costs are calculated for most resources assessed in this chapter. These costs, summarized in Table 8-1, are intended to reflect the intrinsic economic costs of producing energy from these resources and facilitate comparisons of these resources on their own merits. But, the actual 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 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 the equity investment as compensation for the assuming 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.

In this chapter, there are three exceptions to the use of investor-owned utility financial assumptions. These are the analysis of the use of combustion turbines for backing up nonfirm hydropower, the analysis of cogeneration potential and the analysis of WNP-1 and WNP-3. The nonfirm strategies analysis uses melded financial assumptions proportional to the utility owners of nonfirm hydropower (the reference cost estimates for stand-alone simple- and combined-cycle power plants are, however, based on investor-owned utility financing). The cogeneration analysis was based on a model that uses financial assumptions representative of independent developers. WNP-1 and WNP-3 cost assessments are based on the current ownership of these plants.

Representative financial and tax characteristics of investor-owned utilities and other types of resource developers are described in Volume II, Chapter 13. State sales taxes are excluded from all resource capital cost estimates.

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 an inflationary environment, the nominal dollar 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.

Table 8–1
Generating Resource Cost and Availability Summary (1990 Dollars)

Resource	Quantity Available (MWa)	Quantity Promising (MWa)	Cost[a] Range (cents/kWh)	Cost[a] Average (cents/kWh)	Earliest Service	Comment
Biomass (Stand–Alone Power Plants)						
▪ Miscellaneous Wood and Agricultural Residue	90	—	10.1–17.6	14.6	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/est	11.3	2000	
▪ Eastern Washington (Creston)	745	—	n/est	11.1	1996	
▪ Eastern Oregon (Boardman)	745	—	n/est	11.6	1998	
▪ Northern Nevada (Thousand Springs)	716	—	n/est	12.7	1998	
▪ Western Washington Oregon (Centralia)	750	—	n/est	11.9	1998	
Cogeneration						
▪ Biomass Fuels[b]	480	—	< 5.9–8.9	7.5	1995	Resource uncertainty: 0 to 1,570 MW
▪ Natural Gas Fuels[c]	1,720	—	< 5.9–11.8	10.6	1995	Resource uncertainty: 210 to 3,540 MW
Generating Plant Efficiency Improvements						
▪ Hydropower	110	150	0.1–3.3	—	1994	Full recovery over 20 years
▪ Thermal	58	—	0.6–7.5	6.8	1992	
Geothermal						
▪ All Provences	350	1,000	6.3–11.1	10.4	1994	
Hydropower						
▪ New Hydropower	410[d]	—	< 2.4–13.4	8.4	1993	Resource uncertainty: 185 to 900 MW
Natural Gas/Fuel Oil						
▪ Simple–Cycle Combustion Turbines	0	—	—	12.3[e]	1997[i]	
▪ Combined–Cycle Combustion Turbines	2,500	—	—	9.3[e]	1998[i]	
Municipal Solid Waste						
▪ Exclusive of Spokane	30	—	n/est	–1.1[f]	2000	Resource uncertainty: 0 to 100 MWa

Table 8-1 (cont.)
Generating Resource Cost and Availability Summary (1990 Dollars)

Resource	Quantity Available (MWa)	Quantity Promising (MWa)	Cost[a] Range (cents/kWh)	Cost[a] Average (cents/kWh)	Earliest Service	Comment
Nuclear						
▪ WNP-1	818	—	n/app	9.3	1999	
▪ WNP-3	868	—	n/app	8.5	1999	
▪ Advanced Reactors	0	—	n/est	n/est	2000+	Uncertain commercial availability
Ocean						
▪ Wave Power	0	g	—	22	—	Immature technology
▪ Marine Biomass	0	—	—	—	—	Immature technology
▪ Salinity Gradient	0	—	—	—	—	Technology not available
▪ Ocean Current	0	—	—	—	—	Immature technology
▪ Tidal Power	0	0	n/est	84	—	Poor resource in Pacific Northwest
▪ Ocean Thermal	0	0	—	—	—	No resource potential in Pacific Northwest
Solar						
▪ Photovoltaic	0	n/est	n/est	30	1994	
▪ Parabolic Trough with Gas Backup	480	n/est	n/est	18	1994	
Transmission and Distribution Loss Reduction						
▪ Conservation Voltage Regulation	100	—	—	< 2.0[h]	1991	
▪ Efficient Distribution Transformers	64	—	1.4–11.8[h]	—	1992	Full recovery over 20 to 30 years
▪ Reconductoring	99	—	3.9–12.5[h]	—	1992	Full recovery over 20 to 30 years
▪ Federal Projects	39	—	1.0–15[h]	—	1994	
Wind						
▪ All Sites	663	1,000	9.5–16.8	9.9	1995	

[a] Costs are levelized nominal for hypothetical 1990 commercial service, normalized to a 40-year operating service life. Interconnection costs are included.

[b] Pulp and paper and wood products sectors.

[c] Petrochemical, hospital and institutional sectors.

[d] Firm energy. Total average energy is 510 megawatts.

[e] Operating at maximum availability, excludes effects of displacement with nonfirm hydropower.

Table 8–1 (cont.)
Generating Resource Cost and Availability Summary (1990 Dollars)

[f] The cost of electricity from a municipal solid waste plant is affected by the cost of alternative waste disposal methods, and hence the fee paid to the plant operators for taking the waste. For this plan, the price of electricity from a municipal solid waste plant was assumed to be about 8 cents per kilowatt-hour, the approximate avoided resource cost in the year 2000.

[g] Several hundred megawatts of potential.

[h] A conservation resource; costs exclude conservation credit.

[i] Earliest service dates are for sites licensed for coal gasification. Service dates would be two years earlier if no provisions were made for gasification.

Table 8–2
Economic Costs Considered in the Resource Assessments

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

The nominal reference energy costs appearing in this chapter are based on a common, hypothetical 1990 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 are 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.

Biomass

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 forms 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. Biomass plays a lesser role in the generation of electric power.

The total capacity of biomass–fired power plants in the region that sell power to electrical utilities is about 470 megawatts, somewhat over 1 percent of total regional capacity. Three utility plants using wood residues operate in the region. These include the Washington Water Power Kettle Falls Generating Station, the Eugene Water and Electric Board Willamette Steam Plant[2] 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 on average about 90 megawatts of energy.

Additionally, there are about 25 non–utility generating plants in the Northwest using biomass as a primary fuel that contract to sell power to electrical utilities. 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 owners' 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, assessed the 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, which is discussed in a separate section of 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 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 low to moderate efficiency. However, pressurized fluidized–bed power plants under development also may allow solid biomass to be used directly in high–efficiency combined–cycle plants.

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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.

2. Currently shut down.

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 devices 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 the use of solid fuels 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)[3] 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 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 biomass fuels, the costs of collecting and transporting these fuels, seasonal and interannual fluctuation in fuel supply, air quality impacts, 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

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

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 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, the agricultural economy and 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 hydropower. 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, 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 burned without production of sulfur dioxide. Air quality problems associated with the use of biomass fuels involve uncombusted hydrocarbons and particulate material. These can be controlled by furnace design, combustion control and flue gas cleaning technologies, including cyclones, baghouses and 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 re-radiation of this energy back out of the atmosphere. The result of an excess of greenhouse gases appears to be gradual global warming. All carbon-containing fuels, including coal, fuel oil, natural gas and biomass, produce carbon dioxide when burned. Biomass, however, is produced during photosynthesis 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 are regrown, biomass combustion makes a zero net contribution to atmospheric carbon dioxide concentrations.

Biomass Power Potential in the Pacific Northwest

Because major segments of the economy of the Pacific Northwest are based 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 is not considered cost-effective currently 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).

Logging Residues

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.

Biomass Residues Produced

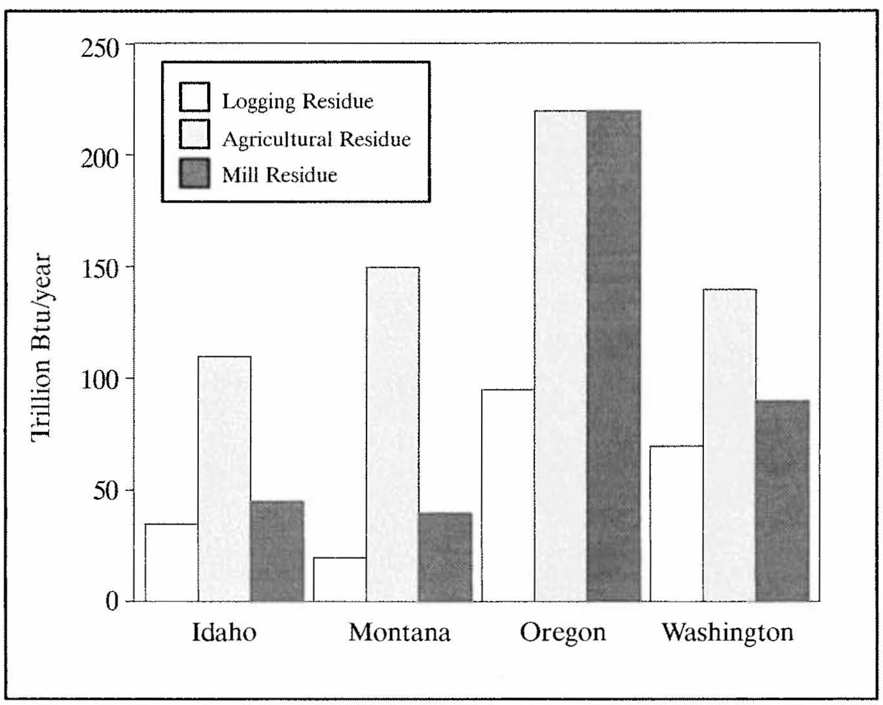


Figure 8-1
Average Production of Biomass Residues in the Pacific Northwest (1977-1987)

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

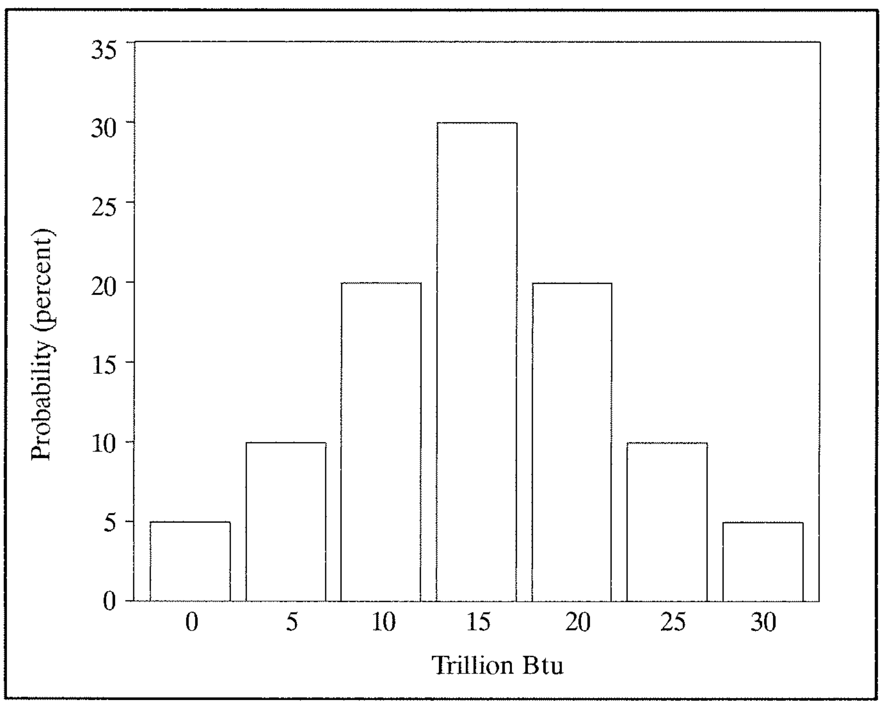
The analysis prepared for the Council (Kerstetter, 1989) estimated a regionwide maximum availability of logging residue for power plant fuel of 36 trillion Btu per year. This amounts to about 20 percent of the annual regional total of logging residue forecast to be produced in the 1991 to 1995 period. This regionwide maximum availability is forecast to decline to about 29 trillion Btu per year in the 2001 to 2010 period. This material is estimated to be available at prices of up to $3.60 per million Btu, delivered. This price represents large material (4 to 8 inches in diameter, or larger, depending on the terrain) that can either be mechanically collected (on flat ground), or skidded to a landing platform (on steep slopes). 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 probable 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 $3.60 per million Btu. This amount would support generation of a most probable value of 110 megawatts of electric energy and a maximum of 230 megawatts of electric energy, if used in stand-alone generation. If all of the fuel were used in cogeneration applications, the energy production potential could be 750 megawatts for the maximum case and 375 megawatts for the most probable case.

Logging Residue Availability

Figure 8-2
Probable Availability of Logging Residue



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.

As little as 5 trillion Btu to as much as 78 trillion Btu of mill residues may be available annually in 2010 for electric power generation at prices ranging from about $0.45 to $1.10 per million Btu (Kerstetter, 1989, escalated to 1990 dollars). 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 are 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 $1.10 per million Btu, the upper end of the range of costs estimated by Kerstetter. This fuel could supply about 75 to 380 megawatts of electric energy if used for stand-alone generation or 250 to 1,250 megawatts if used for cogeneration. Most of this fuel could be used in cogeneration applications because the resource originates near cogeneration opportunities.

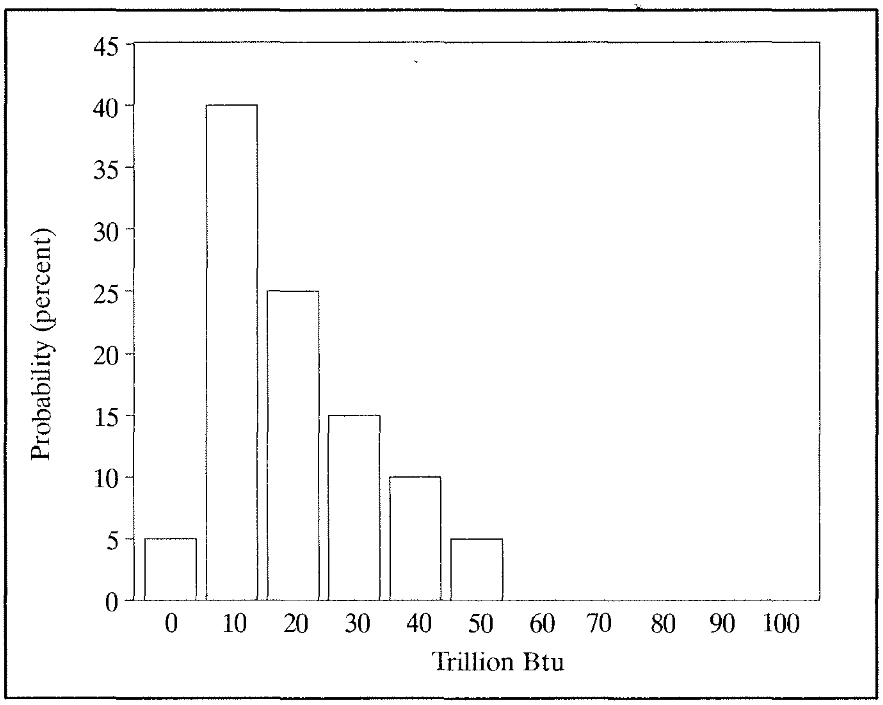
Agricultural Field Residues

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).

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. From this perspective, much of the field residues resource should be viewed as a nonfirm resource.

Mill Residue Availability

Figure 8–3
Probable Availability of Mill Residue



Probably the greatest constraint to the use of agricultural field residues for generation is the difficulty of collection and storage. It may 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 produce approximately 38 to 266 average megawatts of electricity if used in stand-alone generating plants. Most of this generation likely will be stand-alone, since the locational constraints of the resource will limit opportunities for cogeneration.

This fuel is estimated to cost about $2.40 per million Btu on average (Kerstetter, 1989, escalated to 1990 dollars). This estimate includes costs of collection, transportation up to 40 miles and storage.

Other Biomass Resources

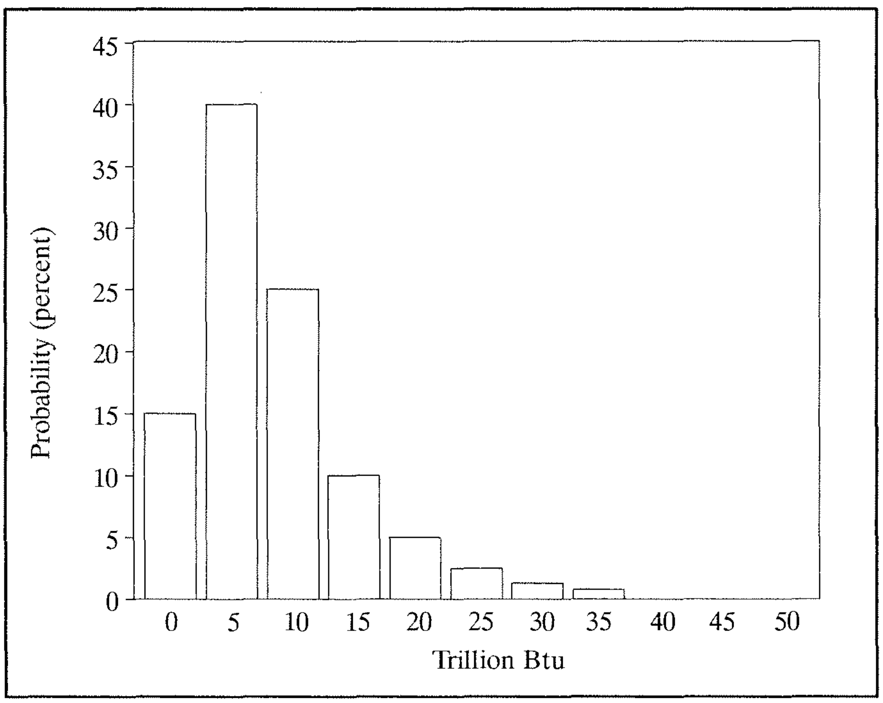
There are other sources of biomass fuels that are not quantified in this power plan. They include spent pulping liquor, urban wood waste, energy crops, landfill gas, digester gas, agricultural processing plant waste, log yard waste, bark from export log operations and others. Energy crops have not been assessed in this plan because earlier studies have generally shown that the growing of biomass specifically for power plant fuel is not economical. Furthermore, there typically are higher value products that could be grown on potential energy crop sites.

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.

These other resources, except energy crops, often present a disposal cost to the waste generator. Thus, if used for fuel, the avoided waste disposal cost may offset collection and transportation costs, and may result in an overall negative cost, similar to the tipping fee charged for disposal of municipal solid waste. Urban wood waste, log yard waste and bark from export operations could serve as a supplemental fuel to mill residues where mill residue is used as fuel on-site.

Agricultural Waste Availability

Figure 8-4
Probable Availability of Agricultural Residue



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 thermal energy produced by the cogeneration plant. The cost of transporting biomass fuels and the widely distributed sources of some of these fuels will limit the amount of this fuel that can be used for cogeneration.

Mill residue offers the greatest potential for cogeneration, because wood product manufacturing facilities often are good candidates for cogeneration. The Council assumed 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 transportation is available between logging operations and wood products manufacturing facilities, approximately 75 percent of fuel expected to be available from logging residues (11 trillion Btu) is estimated to 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, it is assumed that all of this fuel is used for stand-alone generation.

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

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. 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, and subsequently escalated to 1990 dollars. 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.

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.

Table 8-3
Price and Availability of Biomass Residue Fuels (1990 Dollars)

	Availability (TBtu)			
	Generation (Low/Expected/High)	Cogeneration (Low/Expected/High)	Price (delivered) ($/MMBtu)	Escalation Rate (%/yr. real)
Logging Residue	0/4/8	0/11/22	$3.60	0%
Mill Residue	0/2/10	0/8/40	$1.10	0%
Agricultural Residue	0/5/35	0/0/0	$2.40	0%
Total (Generation)	0/11/53		$2.60 (ave.)	0%
Total (Cogeneration)		0/19/62	$2.50 (ave.)	0%

Table 8–4
Cost and Performance Characteristics of a Representative Stand–Alone Biomass Residue Power Plant (1990 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 and Licensing Cost ($/kW)[b]	$30
Option Hold Cost ($/kW/yr.)	$3
Construction Cost ($/kW)[a]	$1,617
Fixed O&M Cost ($/kW/yr.)	$44
Variable O&M Cost (mills/kWh)	3.7
Post–op Capital Replacement Cost ($/kW/yr.)	b
Siting and Licensing Lead Time (months)	24
Construction Lead Time (months)[c]	24
Service Life (years)	30

NOTE: Further details regarding these cost and performance characteristics are supplied in Appendix 8–A.

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

[b] Post–operational capital replacement costs are included in fixed operation and maintenance costs.

[c] Includes engineering, procurement and construction.

Table 8–5
Reference Energy Costs for Representative Stand–Alone Biomass Residue Power Plants

		Energy Costs (cents/kWh)	
Fuel	Fuel Price ($/MMBtu)	Real ($1990)	Nominal
Logging Residue	$3.60	8.9	17.6
Mill Residue	$1.10	5.1	10.1
Agricultural Residue	$2.40	7.1	14.0
Weighted Average	$2.60	7.4	14.6

Biomass Resource Planning Assumptions

The biomass fuel supply of 11 trillion Btu, at an average cost of $2.60 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 available for cogeneration. The cost and availability of this fuel is 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, additional material could be used for electric power generation.

Table 8-6
Biomass Resource Planning Characteristics (Stand-Alone Plants) (1990 Dollars)

	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 Siting and Licensing 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)	$30
Siting and Licensing Hold Cost ($/kW/yr.)	$3
Construction Cost ($/kW)[a]	$1,617
Fixed Fuel Cost ($/kW/yr.)	$0
Variable Fuel Cost (mills/kWh)[b]	38.5
Fixed OM&R Cost ($/kW/yr.)[c]	$44
Variable O&M Cost (mills/kWh)	3.7
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 "Overnight" cost (excludes interest during construction).

b At a weighted average fuel cost of $2.60 per million British thermal units.

c Includes operation, maintenance and post-operational capital replacement costs.

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, because of its efficiency, 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.

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 ranging between $1.10 and $3.60 per million Btu, these plants could produce energy at a costs ranging from about 10 to 18 cents per kilowatt-hour (nominal, 1990 in-service date, normalized to a 40-year service life). (Because of the small size of the available resource, a fuel price representative of the estimated mix of fuels will be used for planning purposes.)

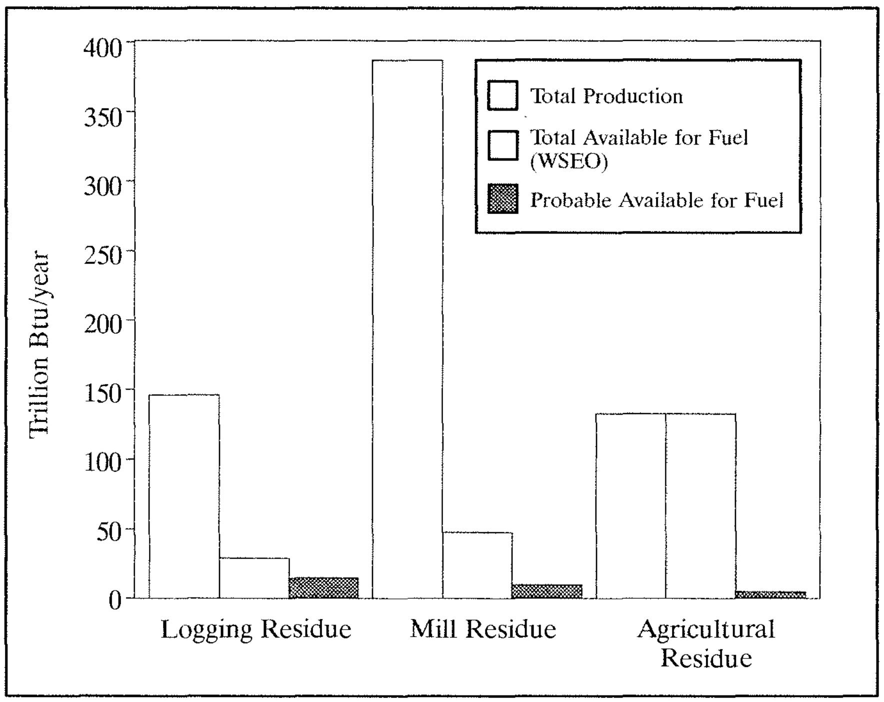
Use of biomass residues for electric power generation should create few environmental impacts. Air quality is likely to improve by controlled combustion of materials that might otherwise be burned in the open.

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.

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.)



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Coal

The combustion of coal to produce electric power is one of the oldest and well-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.[4] 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 10.5 cents per kilowatt-hour (in 1990 dollars), was based on the estimated cost of producing electricity from a new representative coal-fired power plant sited at Boardman in eastern Oregon. This cost determined the maximum amount of electricity from any other resource, including conservation, that could be cost-effective.

But, if new coal-fired power plants were developed to meet future loads, the nature of this development would be more complex than represented in earlier power plans. 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.

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 occurs late in the 20-year planning period. By that time, other more cost-effective or environmentally benign resources should become available to substitute for much of the coal anticipated 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 now considers about 4,700 megawatts of electrical energy from new coal-fired power plants to be available for the resource portfolio. This energy is expected to be available at costs ranging from 11.1 to 12.7 cents per kilowatt-hour.[5] Energy from new coal-fired power plants could be available to meet regional load as early as 1996.

Because of concerns regarding the environmental impacts of coal-fired power plants, the Council in this plan assumes that any new development of large coal-fired power plants would use coal gasifier combined-cycle technology. This technology will improve fuel use efficiency and significantly reduce the release of most air emissions of concern. Though releases of carbon dioxide will be somewhat reduced because of greater fuel use efficiency, these plants would still release substantial quantities of carbon dioxide. The significance of these carbon dioxide releases with respect to global warming and its effects would remain as an important uncertainty associated with future large-scale use of coal.

4. Not included in these figures are 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.

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

Technology

The pulverized coal-fired steam-electric power plant is the established technology for producing electricity from coal. Advanced coal-based generating technologies, including atmospheric fluidized bed combustion and gasifier 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.[6] Although pulverized coal-fired plants are a mature technology, enhancements in plant control, efficiency and reliability have improved the cost and performance of new 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 shorter construction lead times and greater reliability, but they are generally more costly (per unit capacity) to build and operate.

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 scavenges 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. Tacoma Light and Power's 38-megawatt Steam Plant No. 2 has being repowered with fluidized bed furnaces that are 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 is a 330-megawatt repowering of two units of American Electric Power's Philip Sporn plant (Electrical World, June, November 1988).

A gasifier combined-cycle (GCC) power plant consists of a coal gasification plant that 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 arose in the 1970s. Improved versions of the technology have been developed since then. Utility-scale application of the coal gasifier, combined-cycle plant concept was demonstrated at the 100-megawatt Coolwater plant in California. Recently, the Dutch announced construction of a 250-megawatt coal gasification combined-cycle power plant, using the Shell gasification process. This plant is scheduled for operation in 1993. Though current commercial coal gasifier power plants use conventional combustion turbine combined-cycle technology for power production, the development of power generation units of greater efficiency is advancing. Among the concepts being developed are combined-cycle configurations using humid air turbines and molten carbonate fuel cells.

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.

6. The new Clean Air Act requires no net increase of SOx or NOx. Therefore, plant owners will have to reduce emissions from an existing source to allow any new plants to be built and operated.

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, 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 project–to–project 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 oxidized to sulfur dioxide, a gas, in the combustion process. The sulfur dioxide that is released to the atmosphere is 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 from combustion of coals that contain chlorine, may also contribute to acid precipitation formation. The resulting acidic 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.[7] 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 production of nitrogen oxides is controlled by reducing the availability of atmospheric nitrogen in the combustion process, by reducing combustion temperatures, and by removal of nitrogen oxides from exhaust gasses. Combustion modification techniques that reduce the availability of nitrogen include low–excess air firing and staged combustion. Advanced coal–based technologies

7. 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 minimum percentage of sulfur oxides, even when low–sulfur coals are burned.

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 pure oxygen for the gasification process, 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 power plant. Nitrogen oxide formation in the combustion turbine can be controlled by low-excess 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[8] in diameter, can be carried out in the flue gas. These very small particles can be inhaled and can affect human health.

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 with the net effect of warming the earth's surface and lower-level atmosphere). 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 consequent effects. 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 electrical 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 can be mitigated by biologically fixing atmospheric carbon dioxide through reforestation and other processes. Offsets for carbon dioxide releases from one small coal-fired power plant have been secured through arrangements for reforestation of tropical lands. Additional tropical reforestation potential exists as well as the potential for reforestation of certain land in the Northwest. One possibility having multiple environmental benefits would be reforestation of formerly forested riparian lands. The cost and supply of suitable land for large scale reforestation, as would be required for large scale development of new coal-fired power plants, is not well understood.

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 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. These 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.

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

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 of the greater efficiency of these plants.

Withdrawal of water from a river, lake or ocean for power plant services and condenser cooling can impact fish at intake screens. The rate of this impingement is directly related to intake velocity at and around the intake structure, as well as 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 because 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), their physical characteristics, the manner of disposal, and the location of the disposal site. Some by-product applications are available for gasifier slag and some ashes.

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 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 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 long-distance, high-voltage transmission lines 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 can be 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 assessing 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 cost;
- power plant operation and maintenance cost;
- transmission grid interconnection cost;
- transmission losses; and
- decommissioning.

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 air quality constraints would limit capacity to about 1,000 megawatts if conventional pulverized coal-fired plants with flue-gas desulfurization are used. Use of technology having less atmospheric emissions, such as coal gasifier combined-cycle power plants, might permit the development of more capacity at this site.

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 along the Northern Nevada rail corridor. 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 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 so 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 coal. 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 Uinta 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 near 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.

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 rail cars) of coal per year (about 5 unit trains per week), of high energy content East Kootenay or Uinta 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 summarized in Table 8-9.

Integrated coal gasification combined-cycle power plants were used for this analysis. These plants appear to offer the best opportunity both to reduce economic risks associated with expansion of natural gas use for electricity generation, and the least environmental impact of currently available coal technologies.

Coal gasification plants, through increased efficiency and superior pollution control equipment, provide reduced atmospheric emissions compared to conventional coal-fired power plants. The increased efficiency also results in less heat release to the environment, reduced water consumption and less carbon dioxide release per unit of electrical energy produced. Coal gasification equipment can be retrofitted to natural gas-fired combined-cycle power plants. This provides fuel switching opportunities, and also the opportunity to phase construction in which natural gas combined-cycle power plants would be constructed first and could later be converted to coal gasification if natural gas prices increased to excessive levels and global warming turns out not to be a major concern. This strategy would integrate well with strategies to back up nonfirm hydropower using gas-fired combined-cycle plants. Finally, coal gasification power plants offer reduced construction lead time (three years), compared to conventional pulverized coal-fired power plants (five to six years).

Further details regarding representative coal-fired power plant characteristics are provided in Appendix 8-A.

Transmission Routes

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

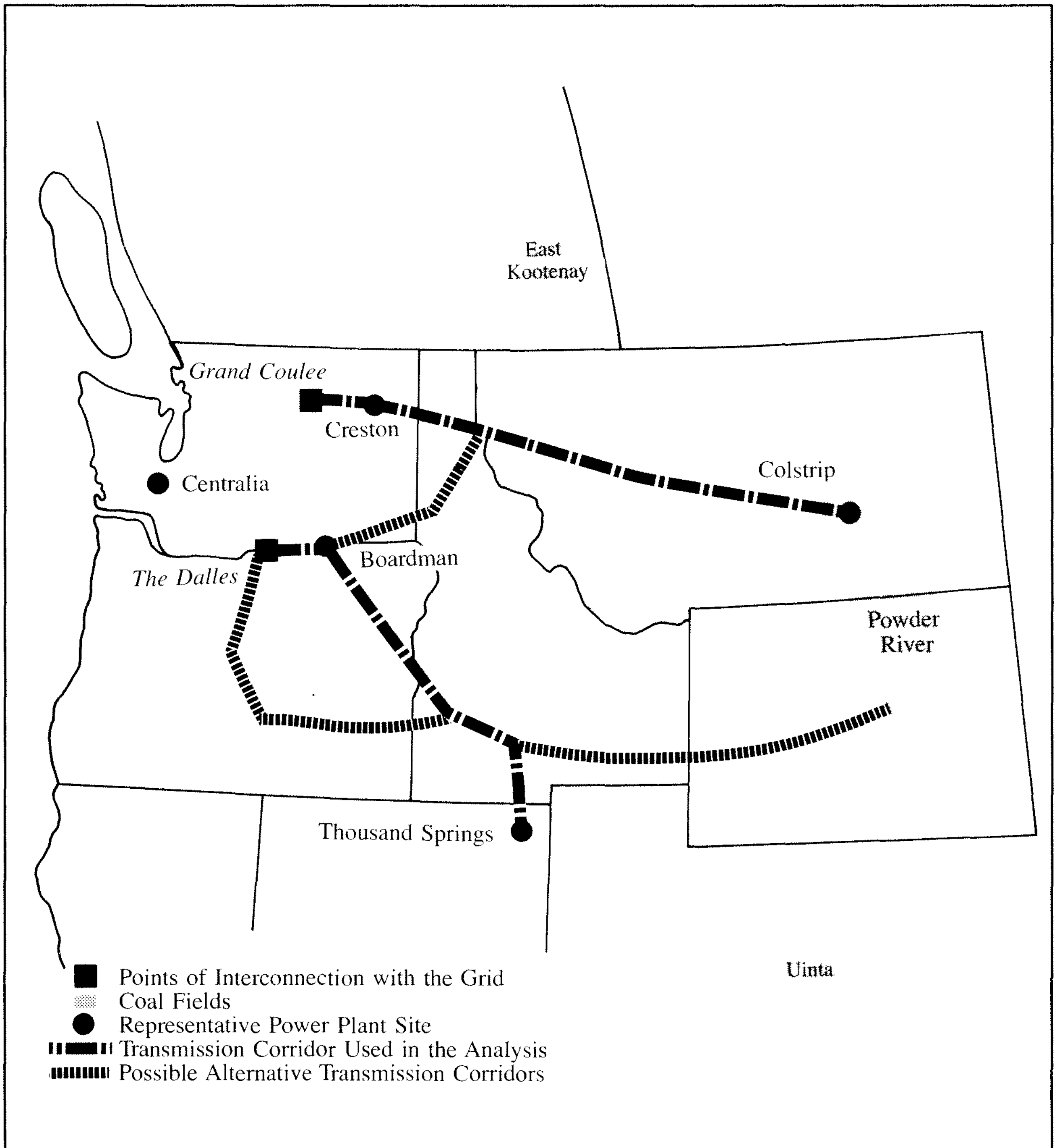

Table 8–7
Assumptions Used for Development of the Coal Supply Curve

Siting Area	Representative Site	Coal Source	Fuel Transportation	Rail Upgrade (miles)	Generating Technology	SO_2 Control (%)	NOx Control (ppm)	Emissions Offset	Cooling	Transmission Intertie[a] (miles)
Eastern Montana/ Wyoming	Colstrip	Powder River Basin	Truck or Conveyor	N/A	IGCC[b]	99%	42[c]	SOx and NOx	Mechanical Draft (Dry)	650
Eastern Washington	Creston	E. Kootenay	Rail	40	IGCC	99%	42[c]	SOx and NOx	Mechanical Draft (Wet)	83
Eastern Oregon	Boardman	E. Kootenay	Rail	None	IGCC	99%	42[c]	SOx and NOx	Mechanical Draft (Wet)	80
Northern Nevada	Thousand Springs	Uinta	Rail	14	IGCC	99%	42[c]	SOx and NOx	Mechanical Draft (Dry)	550
Western Washington/ Oregon	Centralia	E. Kootenay	Rail	None	IGCC	99%	42[c]	SOx and NOx	Mechanical Draft (Wet)	None

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

[b] Integrated gasifier combined–cycle power plant.

[c] Control to about 0.8 lb/MMBtu (as nitrogen).

Table 8–8
Coal Quality and Delivered Prices (1990 Dollars)

	Powder River Basin at Colstrip	East Kootenay at Creston	East Kootenay at Boardman	Uinta at Thousand Springs	East Kootenay at Centralia
Origin	Colstrip, MT	Elkford, B.C.	Elkford, B.C.	Price, UT	Elkford, B.C.
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

(continued)

Table 8–8 (cont.)
Coal Quality and Delivered Prices (1990 Dollars)

	Powder River Basin at Colstrip	East Kootenay at Creston	East Kootenay at Boardman	Uinta at Thousand Springs	East Kootenay at Centralia
Medium Price Forecast ($/MMBtu)					
▪ 1990	0.52	1.34	1.50	1.39	1.74
▪ 1991	0.52	1.35	1.52	1.40	1.76
▪ 1992	0.53	1.37	1.54	1.40	1.78
▪ 1993	0.53	1.39	1.56	1.41	1.80
▪ 1994	0.54	1.40	1.58	1.41	1.82
▪ 1995	0.54	1.42	1.60	1.42	1.84
▪ 1996	0.55	1.44	1.62	1.43	1.86
▪ 1997	0.55	1.46	1.64	1.43	1.88
▪ 1998	0.56	1.48	1.66	1.44	1.90
▪ 1999	0.57	1.49	1.69	1.44	1.92
▪ 2000	0.57	1.51	1.71	1.45	1.94
▪ 2001	0.58	1.53	1.73	1.45	1.96
▪ 2002	0.58	1.55	1.75	1.46	1.98
▪ 2003	0.59	1.57	1.78	1.47	2.01
▪ 2004	0.59	1.59	1.80	1.47	2.03
▪ 2005	0.60	1.61	1.82	1.48	2.05
▪ 2006	0.61	1.63	1.85	1.48	2.07
▪ 2007	0.61	1.65	1.87	1.49	2.10
▪ 2008	0.62	1.67	1.90	1.49	2.12
▪ 2009	0.62	1.69	1.92	1.50	2.14
▪ 2010	0.63	1.71	1.95	1.51	2.17
Standard Deviation	0.22	0.46	0.45	0.36	0.47

Table 8–9
Cost and Performance Characteristics of Representative Coal–Fired Power Plants (1990 Dollars)

	Atmospheric Fluidized Bed Power Plant	250–MW Pulverized Coal Steam Electric Plant	603–MW Pulverized Coal Steam Electric Plant[a]	Integrated Coal Gasifier Combined–Cycle Power Plant[f] (Wet Cooling)	Integrated Coal Gasifier Combined–Cycle Power Plant[f] (Dry Cooling)
Plant Configuration	One 197–MW Unit	Two 250–MW Units	Two 603–MW Units	One 420–MW Unit[e]	One 409–MW Unit[e]
Rated Capacity (MW/unit)	197	250[a]	603[a]	419	409
Peak Capacity (MW/unit)	N/A	262[a]	633[a]	451	441
Equivalent Annual Availability (%)	81%	77%	75%	80%	80%
Heat Rate (Btu/kWh)	9,885	11,005	10,856	9,455	9,490
Siting and Licensing Cost ($/kW)[b]	$44	$35	$24	$40	$41
Siting and Licensing Hold Cost ($/kW/yr.)	$1.50	$1.00	$0.80	$0.60	$0.60
Construction Cost ($/kW)[b]	$1,958	$1,870	$1,366	$2,151	$2,235
Fixed OMR&D Cost ($/kW/yr.)[c]	$41.70	$37.00	$23.80	$62.40	$64.20
Variable O&M Cost (mills/kWh)	5.1	3.3	2.1	0.9	0.9
Siting and Licensing Lead Time (months)[d]	48	48	48	48	48
Construction Lead Time (months)[g]	64	60	72	39	39
Service Life (years)	30	40	40	30	30

NOTE: See Appendix 8–A of this plan for additional information concerning these technologies and sources of cost and performance information.

[a] For each unit of a two–unit plant.

[b] "Overnight" cost (excludes interest during construction).

[c] Includes post–operational capital replacement and decommissioning costs.

[d] For full site–selection and licensing process.

[e] Two 139 megawatt GE MS7001 combustion turbines, one heat recovery steam generator and one 141 megawatt steam turbine–generator.

[f] Figures are for full development of a gasifier combined–cycle power plant. Development of this plant could be staged. See Appendix 8–A.

[g] Includes engineering, procurement and construction.

Environmental Controls

With coal gasification, sulfur oxide emissions can be readily controlled to less than 1 percent of potential by use of well-proven acid gas cleanup equipment. Formation of nitrogen oxides is inherently reduced by the use of oxygen, rather than air as the oxidant in the coal gasifier. Nitrogen oxidation can be further reduced to about one-tenth of that allowed under Federal New Source Performance Standards by "low-NOx" combustors and water injection in the combustion turbines of the combined-cycle plant. Though not included in these estimates, selective catalytic reduction could be used to further reduce releases of nitrogen oxides.

The 1990 amendments to the Clean Air Act establish emissions caps that essentially require that any new utility plant add no net increase to the ambient levels of SOx and NOx. Because residual SOx and NOx emissions from the representative gasifier combined-cycle plants would be small, these residuals could be offset by installing additional controls on SOx and NOx releases at existing power plants, or on other sources of oxides of sulfur and nitrogen. The plant costs used in this analysis include the cost of securing these offsets.

Two of the representative plant sites are located in arid regions, far from major water sources. The cost estimates and performance characteristics of the plants in these locations have been adjusted to reflect the use of dry cooling equipment.

While the increased efficiency of coal gasification combined-cycle power plants results in carbon dioxide releases of about 75 percent of those from pulverized coal-fired power plants, further reduction in carbon dioxide emissions would require unproven, expensive and energy-intensive carbon dioxide scrubbing equipment or carbon fixation by means such as very large-scale growing of trees or other biomass. Thus, the significance of carbon dioxide releases as related to global warming remains the most intractable problem relative to future use of coal either burned directly or after gasification.

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, these assessments included only the costs of interconnecting the plants to the main transmission grid, at Grand Coulee or The Dalles (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 main grid reinforcement is not attributed to specific resource additions. (To ensure a consistent comparison of resources, conservation is given a credit for offsetting the need for main transmission grid and distribution system upgrades.)

Bonneville 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 75 percent. Capital costs were amortized over the 80 percent equivalent availability; production costs were based on the 75 percent capacity factor.

Total project costs included fuel, fuel transportation, power plant pollutant offset and transmission intertie costs. Power delivery to the main 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.

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 areas. Accordingly, we have assumed that about 750 megawatts of energy (at the busbar) could be developed at this site. We assume that units at Creston could be in service within about five

Table 8–10
Reference Levelized Energy Costs for Representative Coal Plants (1990 Dollars)

Siting Area/Representative Site	Real (cents/kWh)	Nominal (cents/kWh)
Eastern Montana (Colstrip)	5.7	11.3
Eastern Washington (Creston)	5.6	11.1
Eastern Oregon (Boardman)	5.9	11.6
Northern Nevada (Thousand Springs)	6.5	12.7
Western Washington/Oregon (Centralia)	6.0	11.9

years of a decision to proceed (24 months to complete site acquisition, licensing and preliminary engineering; 39 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. Local sulfur dioxide emissions could be reduced below existing levels by securing offsets at the existing Boardman plant. Though nearing expiration, a license for two additional units of 1,350 megawatts (maximum) capacity each[9] is currently in effect for this site. We assume that a new license for about 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 about three 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. These concerns might be overcome by use of low-emission technology such as gasifier combined-cycle units and by securing offsets from the existing plants operating in the region, as assumed in this analysis. Water supply issues could be addressed by use of dry cooling, as also assumed in this analysis. Despite the failure of the Thousand Springs proposal, the advantages of this area continue to offer potential for development. We assume that capacity sufficient to produce 750 average megawatts of energy at the busbar—about half the projected size of the Thousand Springs project—could be developed. We assume that a new unit at the Thousand Springs site would require four years for licensing and preliminary engineering and about three years for construction.

Western Washington and western 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 western 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. We assume sufficient new coal-fired capacity to produce 750 average megawatts 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 about three years for construction.

The eastern Montana site, for which fixed transmission costs would be substituted for variable coal transportation costs, offers 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, as assumed in this analysis. 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, such as the coal gasifier combined-cycle plants used in this analysis. 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 would be required to accommodate the transmission of about 2,400 megawatts of capacity. Though a new unit in eastern Montana or Wyoming would require four years for siting, licensing and preliminary engineering and about three years for construction, siting,

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

licensing and constructing the transmission intertie would likely establish the controlling schedule. Accordingly, we have assumed that an eastern Montana plant could be in-service no sooner than year 2000.

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. Because of line losses, somewhat less than 4,700 megawatts of this total could be supplied to the central grid. This is approximately the same as the amount of coal-fired capacity 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 common cost and performance characteristics.

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

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 11.1 to 12.7 cents per kilowatt-hour.[10]

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 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. Air emissions, except for carbon dioxide, could be 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.

References

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Bonneville Power Administration, 1988. *Utility Fuel Supply and Cost Study*, Prepared by Fluor Daniel Corporation for the Bonneville Power Administration, Portland, Oregon.

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10. "Reference" energy costs.

Table 8–11
Coal Resource Planning Characteristics (1990 Dollars)

	Eastern Montana	Eastern Washington	Eastern Oregon	Northern Nevada	Western WA/OR
Total Capacity (MW)[a]	2,130	931	931	895	938
Total Firm Energy (MWa)[a]	1,704	745	745	716	750
Unit Capacity (MW)[a]	387	416	416	391	419
Seasonality	SWP[b]	SWP[b]	SWP[b]	SWP[b]	SWP[b]
Dispatchability	Full	Full	Full	Full	Full
Siting and Licensing Lead Time (months)	48	24	48	48	48
Probability of Siting and Licensing 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)[c]	36	36	36	36	36
Construction Cash Flow (%/yr.)	d	d	d	d	d
Siting and Licensing Cost ($/kW)	$43	$19	$40	$43	$40
Siting and Licensing Hold Cost ($/kW/yr.)	$0.60	$0.60	$0.60	$0.60	$0.60
Construction Cost ($/kW)[e]	$2,722	$2,203	$2,204	$2,659	$2,149
Fixed Fuel Cost ($/kW/yr.)	$0.00	$0.00	$0.00	$0.00	$0.00
Variable Fuel Cost (mills/kWh)	4.9	12.6	14.2	13.2	16.5
Fixed OMR&D Cost ($/kW/yr.)[f]	$70.10	$65.00	$65.00	$69.70	$64.20
Variable O&M Cost (mills/kWh)	0.9	0.8	0.8	0.9	0.8
Earliest Service	2000	1996	1998	1998	1998
Peak Development Rate (units/yr.)	1	1	1	1	1
Operating Life (years)	30	30	30	30	30
Real Escalation Rules (%/yr.)					
▪ Capital Costs	0	0	0	0	0
▪ Fuel Costs	g	g	g	g	g
▪ O&M Costs	0	0	0	0	0

a Delivered to the grid.

b SWP—Slight Winter Peak.

c Rounded from 39 months to three years for purpose of portfolio analysis.

d Construction cash flow for each unit is 12/48/40 percent.

e "Overnight" cost (excludes interest during construction.

f Includes operation, maintenance, post-operational capital replacement and decommissioning costs.

g See Table 8–8.

Cogeneration

Cogeneration is the use of one primary fuel source for sequential generation of thermal and electrical energy. Cogeneration improves overall energy efficiency. Instead of simply burning fuel to create steam or other thermal energy for industrial or commercial processes, cogeneration adds an electricity generation step and uses the "waste" heat from electricity generation for the process heat. 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 such as 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.[11] 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 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 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 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.

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 1989–1990 is

11. 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.

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.

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.

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 probably will work with industry to develop cogeneration for regional use.

Development Issues

There are a number of issues that relate to the development 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, it is likely there 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; such 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.
- Oversizing may help a utility meet its growing loads.

Others argue that oversizing should be discouraged for reasons that follow:

- 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 existing cogenerators in the Northwest are primarily 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 and associated prices of biomass residues 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. However, 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) unknown future production of these materials. 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[12] 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). 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 electrical transmission and, consequently, may be more responsive to increases in demand.

In spite of the optimistic conclusions of Economic Insight, Inc., 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. Since cogeneration is a very efficient use of natural gas, this issue does not apply to the use of natural gas in a cogeneration unit. Nevertheless, natural gas price, driven in part by other uses of gas, can have a significant effect on the cost-effectiveness of cogeneration and represents an important 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

12. This is not a universally held position. Although the total amount of natural gas appears to be plentiful, the ability of the natural gas industry to deliver at peak rates is a subject of some concern.

independently developed cogeneration than for comparable 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, fuel price adjustment provisions could be provided in a cogenerator's power sales contract.

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 standalone 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 often subject to less stringent environmental controls than larger utility generating plants. These problems can be addressed with comparable environmental controls for cogeneration and control-station generation.

Competition with Conservation

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 10 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 for 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 comments received from this seminar, Bonneville contracted with a subcontractor of the ADM study, TechPlan Associates, Inc., to refine the methodology, update data, 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 comments 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 case studies 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 a Council staff issue paper on cogeneration in 1989 (NPPC, 1989b) and are reviewed in the following section. The results displayed in the issue paper 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 14 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[13] 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.

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.[14] 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 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.

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13. 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.

14. Note that these are the prices actually used in the Cogeneration Regional Forecasting Model for this analysis. The Council's natural gas price forecasts have subsequently been adjusted to 1990 dollars, and slightly modified for the near term. See the "Nonfirm Strategies" section of this chapter.

The results of this analysis are shown in Figure 8-7. The figure plots cogeneration potential as a function of electricity sell-back price. The energy values represent the amount of energy that could 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.

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 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 7.5 cents nominal, which is roughly comparable to the long-term avoided cost used in this 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.

Sensitivity tests 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 (NPPC, 1989b).

Table 8-12
Analytical Assumptions

	TechPlan	PNUCC Conservative	PNUCC Aggressive	Council/Bonneville 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
	TechPlan	PNUCC Conservative	PNUCC Aggressive	Council/Bonneville Base
Internal Rate of Return (%)	Penetration (%)			
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 "Nonfirm Strategies."

[b] Large user/small user prices.

[c] Biomass fuel price not to exceed the price of natural gas during the period of the study.

Cogeneration Potential

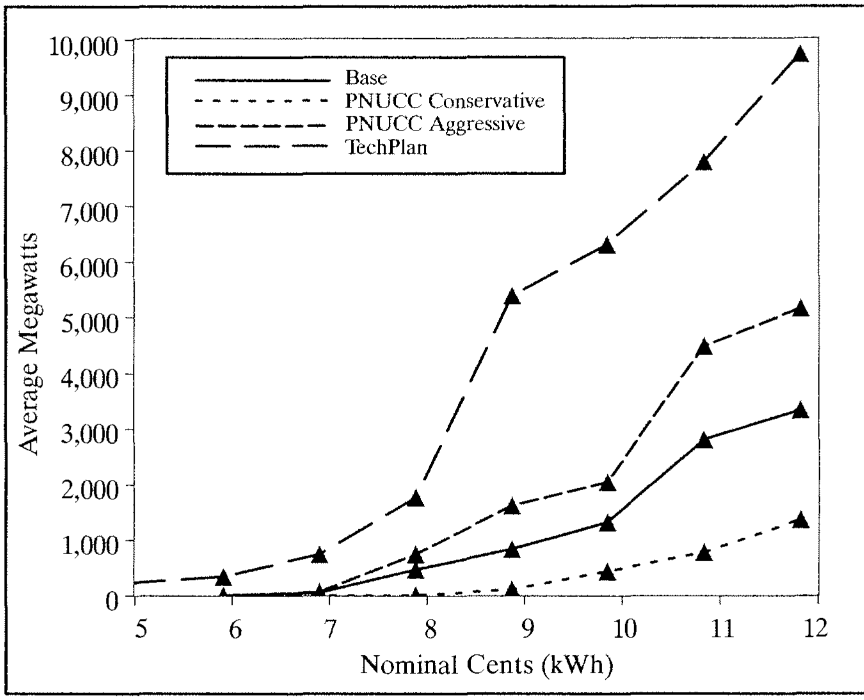

Figure 8–7
Cogeneration Potential under Alternative Assumptions with no Biomass Constraints

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 base case achievable cogeneration potential adopted by the Council is 2,200 average megawatts at 11.8 cents per kilowatt-hour, 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 (Average Megawatts) (1990 Dollars)

Sell–Back Price (cents/kWh)	Base Case	Lower Bound	Upper Bound
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

Upper and lower bounds of achievable cogeneration potential were derived from the PNUCC aggressive and conservative cases, respectively. 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 Btu (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 lower bound 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 upper bound case, biomass fuel availability would also increase 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 and make these larger amounts of cogeneration available to the region, if needed.

The adopted base case supply curve for cogeneration and upper and lower bounding curves are shown in Figure 8-8.

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.

Cogeneration Supply Curve

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

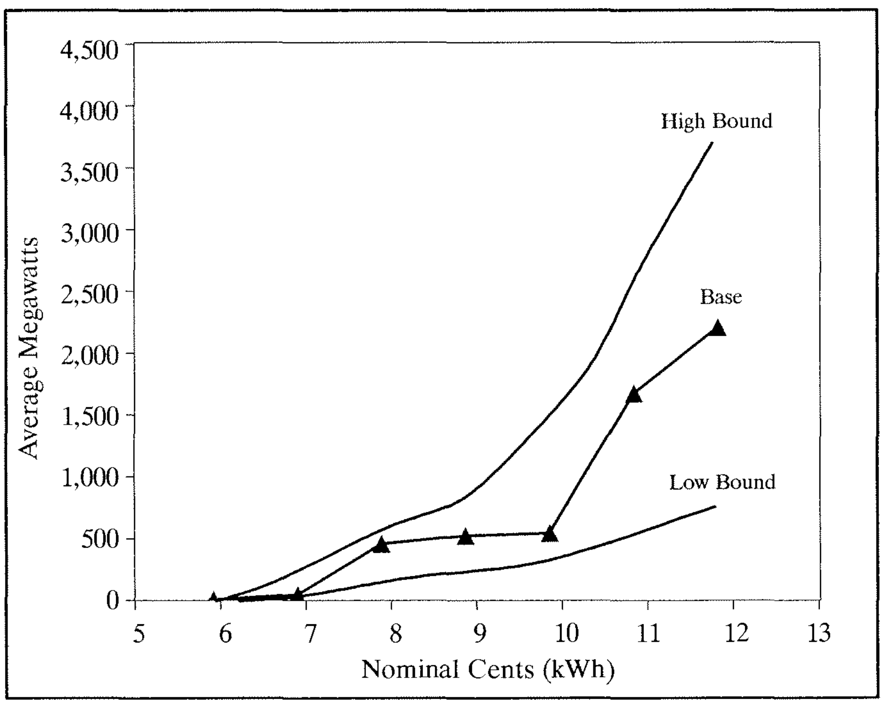

Table 8–14
Cogeneration Planning Assumptions (1990 Dollars)

Resource Block	Cogeneration 1	Cogeneration 2	Cogeneration 3	Cogeneration 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 Siting and Licensing 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 (%/yr.)	[a]	[a]	[a]	[a]
Siting and Licensing Cost ($/kW)	[a]	[a]	[a]	[a]
Siting and Licensing Hold Cost ($/kW/yr.)	[a]	[a]	[a]	[a]
Construction Cost ($/kW)	[a]	[a]	[a]	[a]
Fixed Fuel Cost ($/kW/yr.)	[a]	[a]	[a]	[a]
Variable Fuel Cost (mills/kWh)	[a]	[a]	[a]	[a]
Fixed OM&R Cost ($/kW/yr.)	[a]	[a]	[a]	[a]
Variable O&M Cost (mills/kWh)	[a]	[a]	[a]	[a]
Earliest Service	1995	1998	1999	2002
Peak Development Rate (units/yr.)	10	6	48	34
Operating Life (years)	40	40	40	40
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] Levelized real costs are in 1990 dollars. Costs for levelized nominal costs are based on initial service in 1990.

As discussed in the introduction to this chapter, when resources are developed by non–utility developers, 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 we have assumed 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. One important refinement to model results will be to impose transmission constraints, recognizing the relative locations of cogeneration opportunities and regional loads.

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.

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.[15] 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 are typically more stringent than those for dispersed small-scale plants. State and

15. See PNUCC, 1990b, p. 16.

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.

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[16]

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 1950s 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 electrical energy using the geothermal resources of the Pacific Northwest potentially could be cost–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, described in Volume II, Chapter 1.

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,[17] 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.

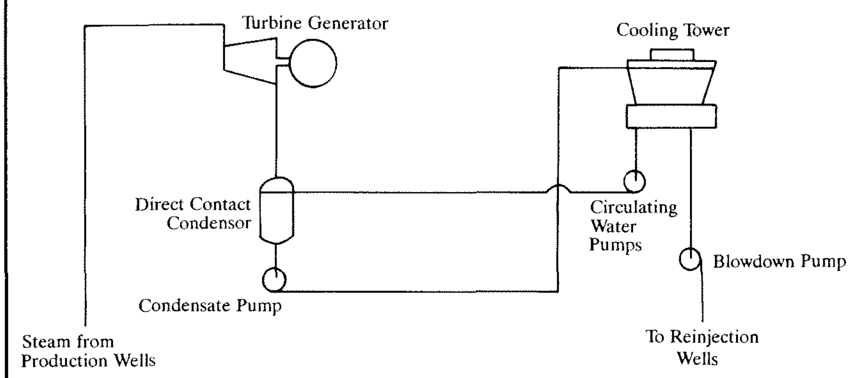
Single–flash power plants (see Figure 8–10) are designed for hot water reservoirs above 220°C (425°F). High–temperature reservoir water flows to the surface via wells and is directed into steam separators. Lower pressure maintained within the separator allows a portion of the hot water to flash into 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.

16. 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.

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

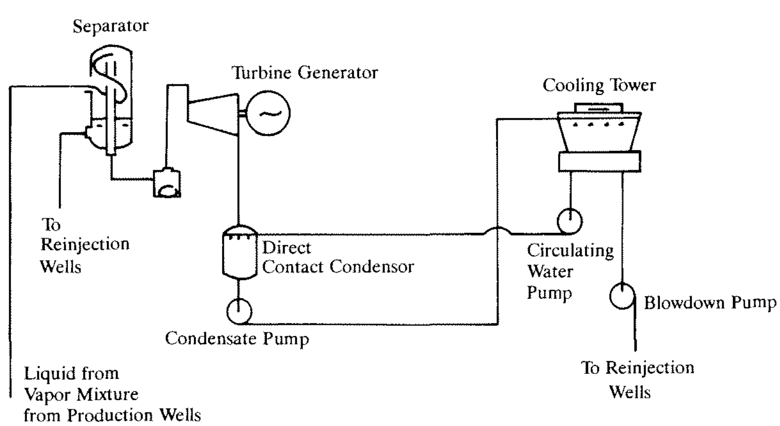
Dry Steam Power Plant

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



Single–Flash Power 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.

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 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.

Double–Flash Power Plant

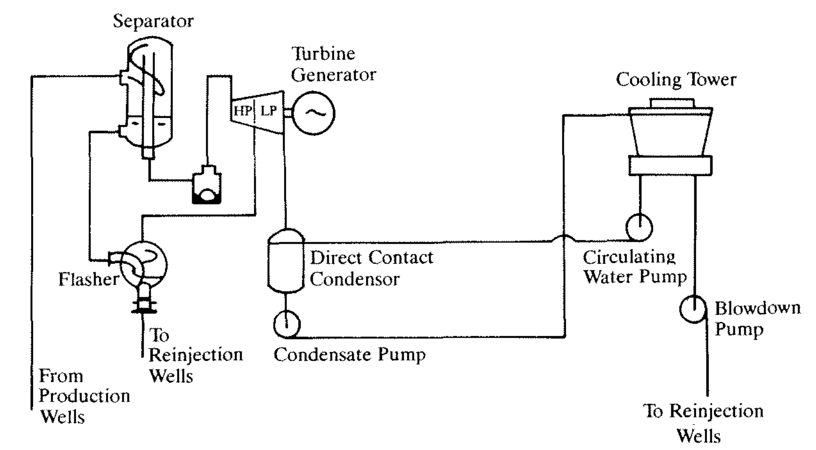


Figure 8–11
Schematic Diagram of a Double–Flash Geothermal Power Plant

Binary Power Plant

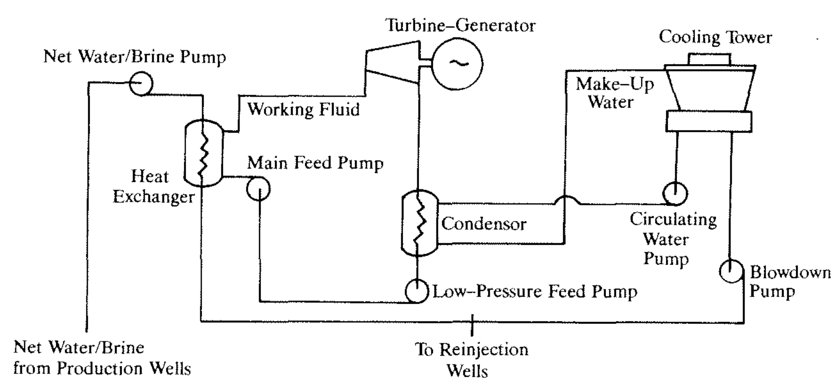


Figure 8–12
Schematic Diagram of a Binary Geothermal Power Plant

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 managed 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.[18] 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.

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, although none greater than 205°C (400°F) (GeothermEx, Inc., 1987).

18. 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.

Geological Provinces

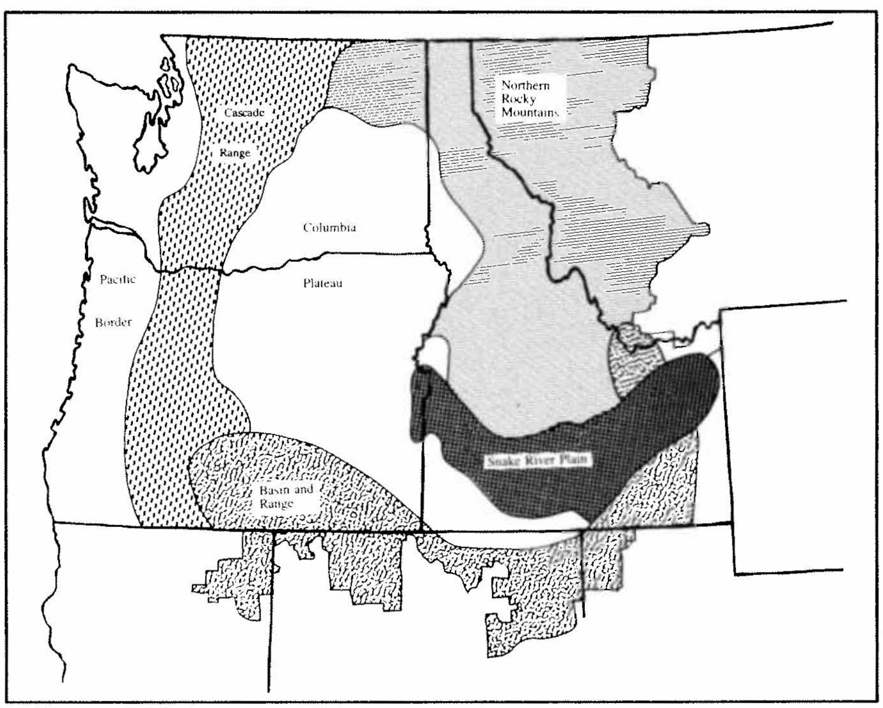


Figure 8-13
Structural Provinces of the Pacific Northwest

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 issuing 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 lack of 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 Caldera and nearby features including the Lava Cast Forest, the Northwest Rift Zone and Lava Butte has subsequently been designated as the Newberry National Volcanic Monument (P.L. 101-522). The Forest Service estimates that this designation will preclude the development of about 65 percent of the estimated geothermal potential of the Newberry Caldera Known Geothermal Resource Area (KGRA). 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 Hot Springs, 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

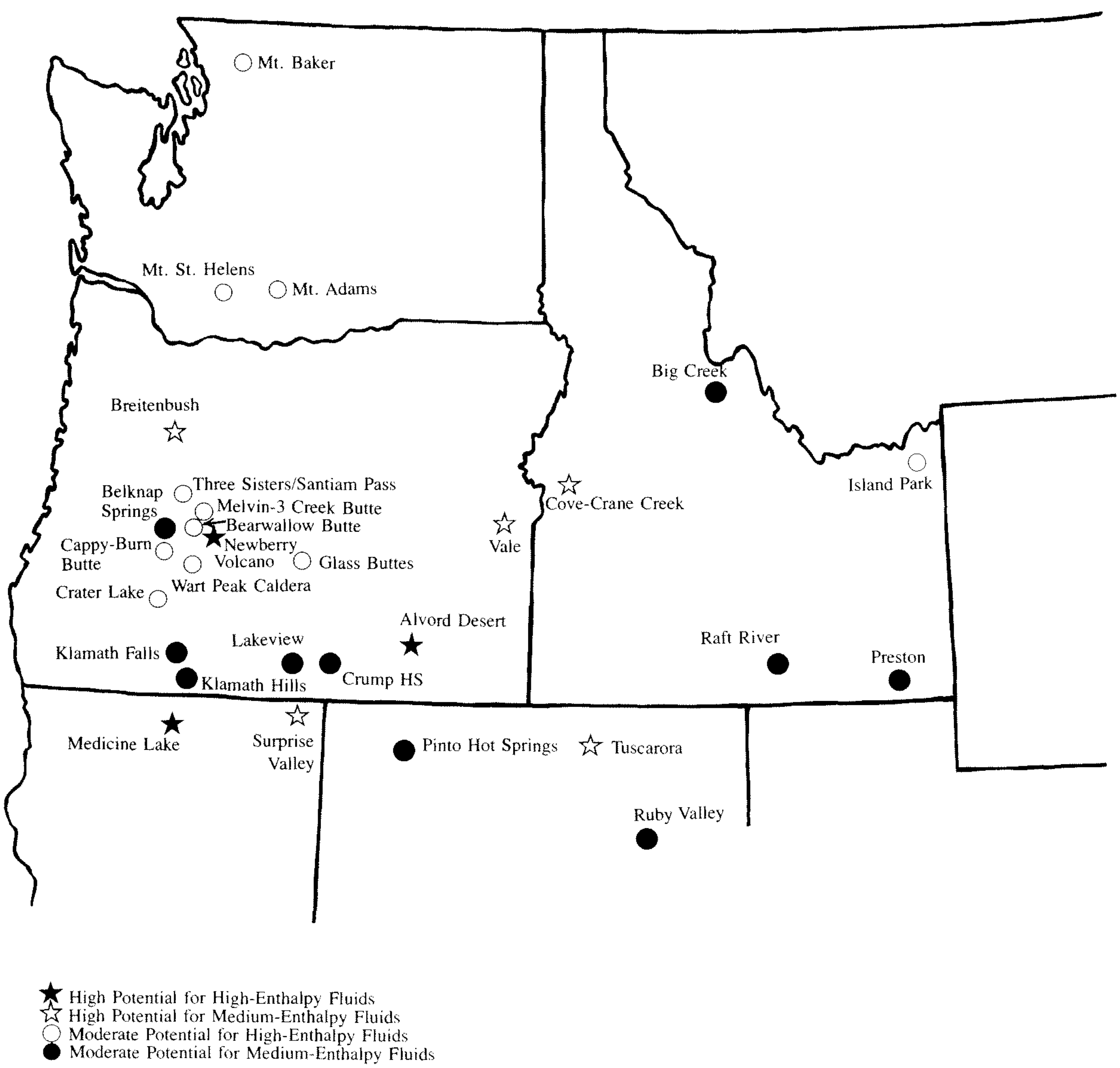
[a] Top sites from 1985 Four-State Study noted in 1986 Power Plan.

[b] Reduced 80 percent from 1986 Power Plan, due to land-use restrictions.

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

Geothermal Resource Areas

Figure 8-14
Geothermal Resource Areas
in the Pacific Northwest



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 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, require less capital investment per kilowatt and have greater reliability. These will be commercial units ranging from 30 to 80 megawatts capacity. 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 owners' 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. Using the information described above, costs and performance assumptions were compiled for two representative Northwest geothermal power plants. These are shown in Table 8-17.

Reference Energy Cost Estimates

Reference energy costs were calculated for typical Basin-and-Range and Cascades geothermal power plants. The average costs of the representative binary and flash plants (see Table 8-17) were chosen as representative of Basin-and-Range development. Representative flash plant characteristics were considered as representative of development in the Cascades.

The reference energy costs for representative Basin and Range and Cascades plants are shown in Table 8-18. These costs are calculated using the 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.

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.

19. Expressed in 1990 dollars.

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
▪ Owners' 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,b]		
▪ Land Acquisition	Federal lease	Federal lease
▪ Site Utilities and Services	$25	$25
▪ Construction:		
▪ Materials	$625	$725
▪ Labor	$600	$700
▪ Engineering and Management	$140	$200
▪ Pre–production (Start Up)	$25	$30
▪ Contingency Allowance	c	c
▪ Owners' Costs During Construction	$90	$100
▪ Switchyard	$10	$10
▪ Transmission Interconnect to the Grid[d]	$40	$70
▪ Spare Parts Inventory	$20	$30
▪ Royalties	Federal lease	Federal lease
Fluid Costs[a]		
▪ If Wellfield Capitalized:		
▪ Wellfield Capital ($/kW, net)	$550	$640
▪ Wellfield O&M ($/kW/yr.)	$19.25	$22.40
▪ Commodity Costs, if Purchased (mills/kWh)[e]	20.0	26.0
Operating and Maintenance Costs		
▪ Fixed O&M costs ($/kW/yr.)[f,a]	$45	$53
▪ Variable O&M costs (mills/kWh)[g]	3	3
▪ Consumables ($/kW/yr.)[a]	$10	$10
▪ Post–operational Capital Costs[a]	h	h
Decommissioning Cost ($/kW)[h]	$80[i]	$80[i]

[a] Values shown are for flash plants; 20 percent greater for binary.

[b] "Overnight" construction costs, exclusive of interest.

Table 8–16 (cont.)
Geothermal Plant Cost Components—Low and Mid-Range (1990 Dollars)

[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 of steam at 16 pounds per kilowatt-hour. Mid-range case: $1.45 per 1,000 pounds of 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
Cost and Performance Characteristics of Representative Stand-Alone Geothermal Power Plants (1990 Dollars)

	25-Megawatt Binary Plant and Wellfield	50-Megawatt Flashed Steam Plant and Wellfield
Rated Capacity (MW)	25	50
Peak Capacity (MW)	25	50
Equivalent Availability (%)	90%	90%
Heat Rate (Btu/kWh)	9,280	9,280
Siting and Licensing Cost ($/kW)	$65	$65
Option Hold Cost ($/kW/yr.)	$13	$13
Construction Cost ($/kW/hr.)[a]	$2,941	$2,464
Fixed OMR&D Cost ($/kW/hr.)[b]	$128	$104
Variable O&M Cost (mills/kWh)	8.0	5.0
Siting and Licensing Lead Time (months)	24	24
Construction Lead Time (months)[c]	24	36
Operating Life (years)	30	30

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

[b] Includes operation, maintenance, post-operational capital replacement and decommissioning costs.

[c] Includes engineering, procurement and construction

Table 8–18
Reference Energy Costs for Representative Geothermal Power Plants (1990 Dollars)

	Real (cents/kWh)	Nominal (cents/kWh)
25-Megawatt Basin-and-Range Plant	5.3	10.4
50-Megawatt Cascades Plant	4.8	9.5

Table 8-19
Possible Cost Distribution: Northwest Geothermal Development (1990 Dollars)

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

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 estimated to be 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 electrical 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 described earlier.

Costs used for the "Cascades Commercial" block were based on the flash steam plant costs of Table 8–17.

Table 8–20
Geothermal Planning Assumptions (1990 Dollars)

	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 Siting and Licensing 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 (%/yr.)	50/50	25/50/25
Siting and Licensing Cost ($/kW)	$65	$65
Siting and Licensing Hold Cost ($/kW/yr.)	$13	$13
Construction Cost ($/kW)[a]	$2,702	$2,464
Fixed OMR&D Cost ($/kW/yr.)[b]	$116	$104
Variable O&M Cost (mills/kWh)	6.5	5.0
Earliest Service	1994	1998
Peak Development Rate (units/yr.)	4	4
Service Life (years)	30	30
Real Escalation Rates (%/yr.)		
▪ Capital Costs	0%	0%
▪ Fuel Costs	0%	0%
▪ O&M Costs	0%	0%

[a] "Overnight" cost, excludes interest during construction.

[b] Includes operation, maintenance, post–operational capital replacement and decommissioning costs.

Conclusions

The geothermal energy resources of the Pacific Northwest may have the potential to produce several thousand megawatts of electrical energy at costs less than or competitive with electrical 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 electrical 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 base-load power at availabilities exceeding 90 percent. Electric energy from commercial-scale plants at better Northwest sites are estimated to cost about 9.5 to 10.5 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 to better understand environmental mitigation requirements 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, Chapter 1.

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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 have 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 are 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 potential. As described below, the Council estimates that about 1,060 megawatts of new hydropower capacity can likely be developed at costs less than 13.4 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; and some undeveloped sites..

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 by connecting the turbine to an electrical generator. Hydropower projects take many forms. 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 project. Because hydropower equipment operates under relatively benign ambient conditions, the 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 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 generally low due to 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.

During construction and throughout the operating life of hydroelectric projects, varying environmental effects can be expected, based primarily on location of the project, type of project 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,
- hydrology impacts,
- erosion and sedimentation,
- land use impacts,
- dust and noise during construction, and
- fish and wildlife impacts.

Although the environmental issues that may be raised for any one project depend heavily on the site characteristics of the project, projects that involve an existing dam generally or other water control structure 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

Chemical, biological or thermal impacts on water quality may result from the construction and operation of hydroelectric projects. 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 downstream flow are most likely to result from 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 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 hydrostatic pressure causes 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

Possible changes in the hydrologic regime resulting from hydroelectric development include converting a portion of a free-flowing stream into backwater, diverting water from its natural course and altering the natural groundwater recharge pattern. These changes in hydrology are environmental impacts in themselves, but they also create secondary 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) 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 affect erosion and sedimentation patterns in different ways. In general, sediment will settle in a reservoir because of the reduction in flow velocities. As a result, increased sedimentation occurs in the backwater formed by the reservoir. Mudflats and bars may develop and reservoir storage capacity is lost. Consequently, the water released from the reservoir has a reduced sediment load. Because the released water can carry a greater sediment load, channel scour may occur 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 depends 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 and Noise During Construction

Construction activities, particularly earth moving in arid regions, 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.

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

Many hydroelectric dams in the Pacific Northwest present 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 lake-like 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 wildlife. 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.

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 that have bee affected by hydropower. 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 hydropower 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 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 13.4 cents per kilowatt-hour or less. This estimate has not been revised for the 1991 Power 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 documented in 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 subject to the FERC hydropower licensing process. Next, projects preempted 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 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 8-21. 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 13.4 cents per kilowatt-hour or less.[19]

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 13.4 cents per kilowatt-hour, or less. This upper-bound supply curve is tabulated in Table 8-22.

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 Appendix 8-B) 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 13.4 cents per kilowatt-hour, or less. This lower-bound supply curve is tabulated in Table 8-23.

19. 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 8–21
Cost and Availability of New Hydropower (Achievable) (1990 Dollars)

Levelized Cost (cents/kWh)		Average Energy		Firm Energy	
Nominal	Real	Incremental (MWa)	Cumulative (MWa)	Incremental (MWa)	Cumulative (MWa)
< 2.4	< 1.2	9	7	7	
2.4 - 3.7	1.2 - 1.9	33	42	26	33
3.7 - 4.9	1.9 - 2.5	14	56	11	44
4.9 - 6.1	2.5 - 3.1	58	114	46	90
6.1 - 7.3	3.1 - 3.7	74	188	59	149
7.3 - 8.7	3.7 - 4.4	55	243	44	193
8.7 - 9.9	4.4 - 5.0	86	329	69	262
9.9 - 11.0	5.0 - 5.6	72	401	58	320
11.0 - 12.2	5.6 - 6.2	88	489	70	390
12.2 - 13.4	6.2 - 6.8	23	512	18	408

Table 8–22
Cost and Availability of New Hydropower (Upper Bound) (1990 Dollars)

Levelized Cost (cents/kWh)		Average Energy		Firm Energy	
Nominal	Real	Incremental (MWa)	Cumulative (MWa)	Incremental (MWa)	Cumulative (MWa)
< 2.4	< 1.2	16	16	13	13
2.4 - 3.7	1.2 - 1.9	145	161	116	129
3.7 - 4.9	1.9 - 2.5	35	196	28	157
4.9 - 6.1	2.5 - 3.1	207	403	166	323
6.1 - 7.3	3.1 - 3.7	127	530	102	425
7.3 - 8.7	3.7 - 4.4	106	636	85	510
8.7 - 9.9	4.4 - 5.0	132	768	106	616
9.9 - 11.0	5.0 - 5.6	179	947	143	759
11.0 - 12.2	5.6 - 6.2	119	1,066	95	854
12.2 - 13.4	6.2 - 6.8	70	1,135	56	910

Table 8-23
Cost and Availability of New Hydropower (Lower Bound) (1990 Dollars)

Levelized Cost (cents/kWh)		Average Energy		Firm Energy	
Nominal	Real	Incremental (MWa)	Cumulative (MWa)	Incremental (MWa)	Cumulative (MWa)
< 2.4	< 1.2	2	2	2	2
2.4 - 3.7	1.2 - 1.9	12	14	10	12
3.7 - 4.9	1.9 - 2.5	4	18	3	15
4.9 - 6.1	2.5 - 3.1	31	49	25	40
6.1 - 7.3	3.1 - 3.7	17	66	14	54
7.3 - 8.7	3.7 - 4.4	24	90	19	73
8.7 - 9.9	4.4 - 5.0	50	140	40	113
9.9 - 11.0	5.0 - 5.6	30	170	24	137
11.0 - 12.2	5.6 - 6.2	47	217	38	175
12.2 - 13.4	6.2 - 6.8	13	230	10	185

New Hydropower Planning Assumptions

The supply of achievable new hydropower that appears in Table 8-21 is the amount of this resource that the Council has counted on for the resource portfolio of this 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 8-24.

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 hydropower site data bases, 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. These resources range in cost from less than 2.4 cents per kilowatt-hour to 13.4 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 to as much as 900 megawatts of firm energy.

The principal issue 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.

Table 8-24
New Hydropower Planning Assumptions (1990 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 Siting and Licensing 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 (%/yr.)	25/50/25	25/50/25	25/50/25	25/50/25
Siting and Licensing Cost ($/kW)	$80	$100	$138	$167
Siting and Licensing Hold Cost ($/kW/yr.)	$3	$3	$5	$6
Construction Cost ($/kW)[a]	$1,060	$1,329	$1,831	$2,216
Fixed OM&R Cost ($/kW/yr.)[b]	$23	$29	$39	$48
Variable Operating Cost (mills/kWh)	0.0	0.0	0.0	0.0
Earliest Service	1991	1991	1991	1991
Peak Development Rate (units/yr.)	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" cost (excludes interest and escalation during construction).

[b] Includes operation, maintenance and post-operational capital replacement costs.

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Municipal Solid Waste[20]

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 incineration for energy recovery more valuable and makes adoption of the practice more likely.

The Pacific Northwest has four operating municipal solid waste facilities that generate electricity. The first completed is in Marion County, Oregon. Design capacity of this facility is 550 tons per day of municipal solid waste, with a net electricity 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. Tacoma Light Division has repowered 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 32 megawatts of energy. This plant uses a circulating fluidized-bed furnace with limestone injection for sulfur dioxide control and a baghouse for particulate control.

The city of Spokane, Washington, is constructing an 800-ton per day facility that generates 16 megawatts of power.

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 and permitting municipal solid waste generation projects.

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 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.

20. 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.

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

Issues associated with the development of municipal solid waste-to-energy plants include plant siting, effects of recycling, air quality concerns and global warming concerns.

Plant Siting

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. This situation increases uncertainty regarding the future quality and availability of municipal solid waste for generation.

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 8-25 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 (Table 8-25). This concern can cause lengthy delays in siting and obtaining permits for new facilities. For example, the 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.

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. But, if this biomass is replaced by replanting trees or other plants, 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 contributes lower levels of carbon dioxide to the atmosphere than generation 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.

Table 8–25
Measured Emissions from Stanislaus County Resource Recovery Facility

Parameter	Concentration	Permit Level
Nitrogen Oxides (ppm)[a]	103	200
Sulfur Oxides (ppm)	4.1	30
Carbon Dioxide (ppm)	43	400
Total Hydrocarbons (as CH4) (ppm)	4	70
Particulate (gr/dscf)[b]	0.011	0.0275
Hydrochloric Acid (ppm)	1.28	50
Fluoride (ppm)	0.16	3
Ammonia (ppm)	4.4	50
Arsenic (ug/Nm3)[c]	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.

b Grains per dry standard cubic foot (one grain = 1/7,000 pound; one dry standard cubic foot = one moisture–free cubic foot of gas at 59°F and at a pressure of one atmosphere.)

c Micrograms per normal cubic meter (one normal cubic meter = one cubic meter of gas at 0°C (32°F) and at a pressure of one atmosphere).

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

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), subsequently released as a Council Staff Issue Paper (NPPC, 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[21] 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 (1988 dollars).

The quantity of municipal solid waste generated depends on population and economic activity. For most areas, 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 8–26. This table excludes waste required for operating facilities in Marion County, Oregon; Skagit County, Washington; Bellingham, Washington; Tacoma, Washington; and planned facilities in Spokane, Washington.

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

21. 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.

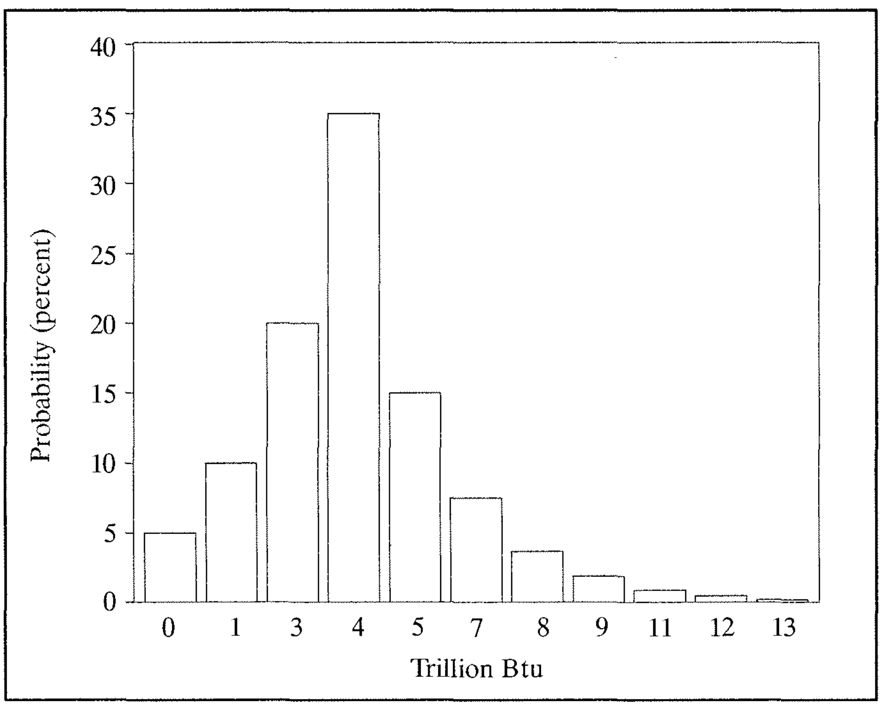
these plants often are sufficiently attractive to allow mitigation or compensation for negative impacts on nearby communities, the Council's judgment is that use of the entire municipal solid waste resource for electricity generation is unlikely during the planning period. Figure 8-15 shows the estimated 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. The plant operator can expect to receive about $7.00 per million Btu (approximately $32 per ton) of fuel taken (1990 dollars).

Table 8-26
Municipal Solid Waste Potentially Available for Energy Recovery

State	Municipal Solid Waste (tons/day)	Equivalent Thermal 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

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 of the type of plant that might be developed to produce electricity consistent with meeting future refuse disposal needs in this region. 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 cost and performance characteristics of the representative plant are shown in Table 8-27. The costs were taken from an earlier Council study (Battelle, 1982a) and escalated to 1990 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 stringent environmental controls than the plants upon which these costs are based. This could result in increased construction and operating costs. The figures of Table 8-27 have, however, been compared to waste-to-energy plant cost and performance estimates from more recent sources, and appear to be reasonable. 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 8-27 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 8-27
Cost and Performance Characteristics of a Representative Municipal Solid Waste Power Plant (1990 Dollars)

	10-Megawatt Mass-Burn Steam Electric Plant
Rated Capacity (MW)	10
Peak Capacity (MW)	10
Equivalent Availability (%)	87%
Annual Energy (MWa)	8.0
Heat Rate (Btu/kWh)	20,000
Siting and Licensing Cost ($/kW)	$204
Option Hold Cost ($/kW/yr.)	$7
Construction Cost ($/kW)[a]	$5,190
Fixed O&M Cost ($/kW/yr.)	$337
Variable O&M Cost (mills/kWh)[b]	0
Post-op Capital Replacement Cost ($/kW/yr.)	$95
Decommissioning ($/kW/yr.)	$2
Siting and Licensing Lead Time (months)	24
Construction Lead Time (months)[c]	36
Service Life (years)	30

NOTE: Further details regarding these cost and performance characteristics are supplied in Appendix 8-A.

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

[b] Variable O&M costs are included in the fixed O&M cost component.

[c] Includes engineering, procurement and construction.

Table 8–28
Reference Energy Costs for a Representative Municipal Solid Waste Power Plant
(cents per kilowatt–hour)

	Real ($1990)	Nominal
10–Megawatt Municipal Solid Waste Plant	-0.6	-1.1

Reference Energy Cost Estimates

Reference energy costs for the representative municipal solid waste power plant are shown in Table 8-28. These costs were calculated using the reference financial and service date assumptions discussed in the introduction to this chapter. The plant is assumed to operate at an 80 percent capacity 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 ($-7.00 per million Btu). That is, municipal solid waste haulers pay the plant operator for the right to dump the solid waste. Although the Council has estimated a negative *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 interpretation of this situation is that opposition is due to environmental costs, either real or perceived, that are not represented in Table 8–28. 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. In addition, increased recycling could reduce pressure on landfills, which would tend to reduce the amount of municipal solid waste and to lower tipping fees. Increased recycling also is likely to remove some of the highest–quality fuel (paper) from the waste stream.

These factors 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.

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 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 Council's treatment of 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 8-29.

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 8–28 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 real or perceived 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 8–29
Municipal Solid Waste Planning Characteristics (1990 Dollars)

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 Siting and Licensing Success (%)	33
Siting and Licensing Shelf Life (years)	5
Probability of Hold Success (%)	75
Construction Lead Time (months)	36
Construction Cash Flow (%/yr.)	[b]
Siting and Licensing Cost ($/kW)	[b]
Siting and Licensing Hold Cost ($/kW/yr.)	[b]
Construction Cost ($/kW)[c]	[b]
Fixed OM&R Cost ($/kW/yr.)	[b]
Variable O&M Cost (mills/kWh)	[b]
Earliest Service	2000
Peak Development Rate (units/yr.)	One unit every 3 years
Service Life (years)	30
Real Escalation Rates (%/yr.)	
▪ Capital Costs	0%
▪ Fuel Costs	0%
▪ O&M Costs	0%
Power Purchase Price (cents/kWh)[b]	
Levelized Real	4.1[d]
Levelized Nominal	8.0[d]

[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] "Overnight" cost (excludes interest during construction).

[d] These prices are assumed to be negotiated between municipal solid waste plant operators and utilities and are set here at the approximate 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.

Northwest Power Planning Council (NPPC). 1989. *Biomass Resources* (Staff Issue Paper 89-41). Northwest Power Planning Council, Portland, Oregon. October 1989.

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 explores higher-valued uses for this energy than serving the California displacement market, currently 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. 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 combined-cycle combustion turbines, sited in the Northwest and burning natural gas.

The Council recognizes that the increased value of the nonfirm energy also increases the incentive of system operators to shape hydro system operation to maximize the displacement of the gas generation or other equivalent resources. This action is constrained by the requirements of the water budget[22] in the Council's Columbia River Basin Fish and Wildlife Program. 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 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 and will further amend the program as necessary to ensure this. Possible actions to augment flows for fish migration could result in more nonfirm energy generation.

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 62 percent of the total firm energy 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 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) is approximately 16,600 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 better 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.

22. 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

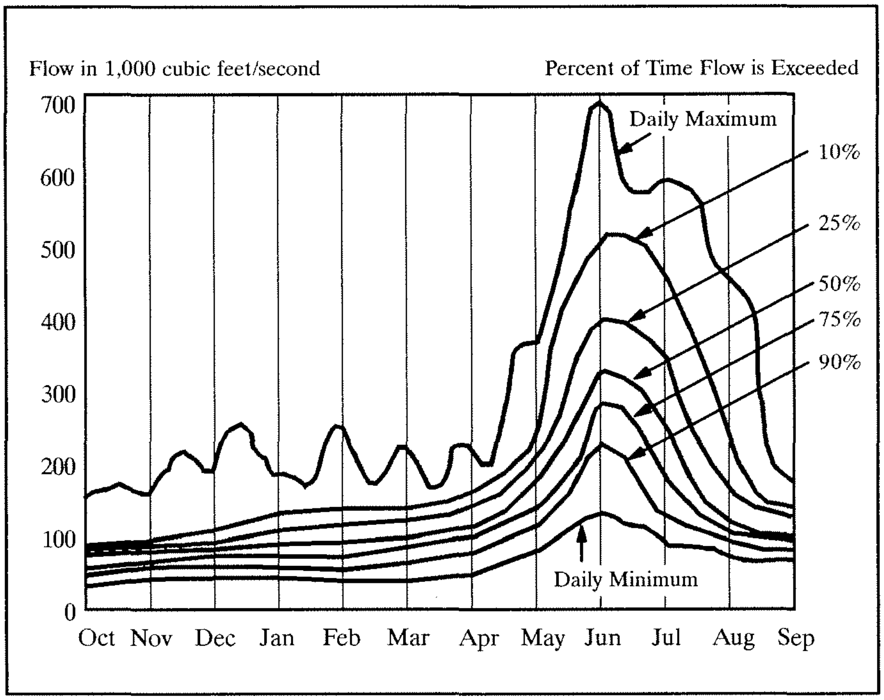


Figure 8-16
Average Daily Columbia River Natural Flow at The Dalles, Oregon

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.

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.

Existing Uses of Nonfirm

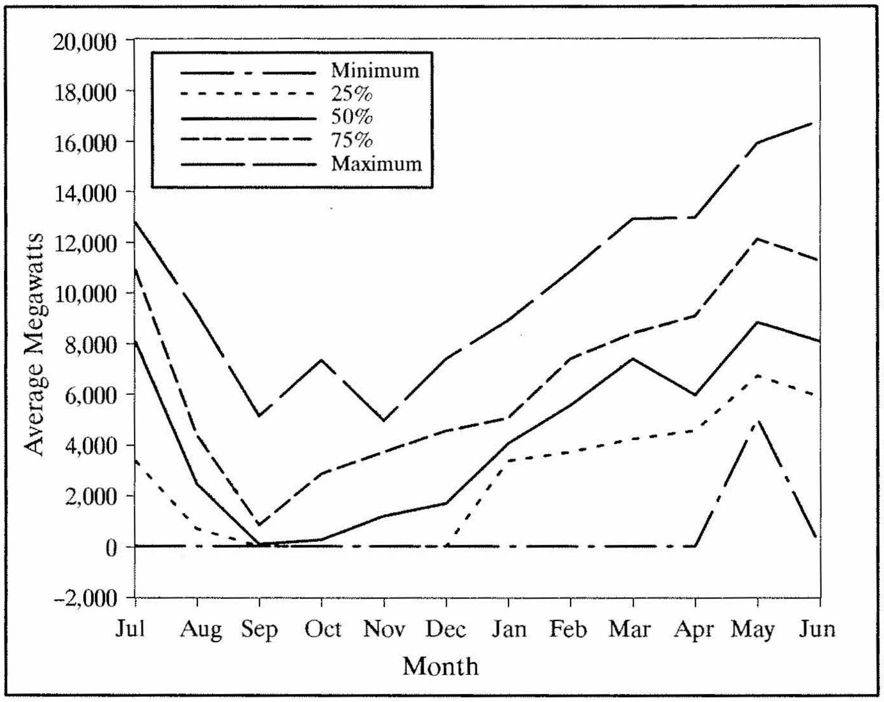
Currently, there are three major uses of Northwest nonfirm energy. The first is to serve the interruptible or top quartile of Bonneville's direct service industries. The direct service industry load is divided into quartiles, and a different set of restriction rights applies to each of the quartiles. 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.[23] 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 these industries. 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.

23. "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.

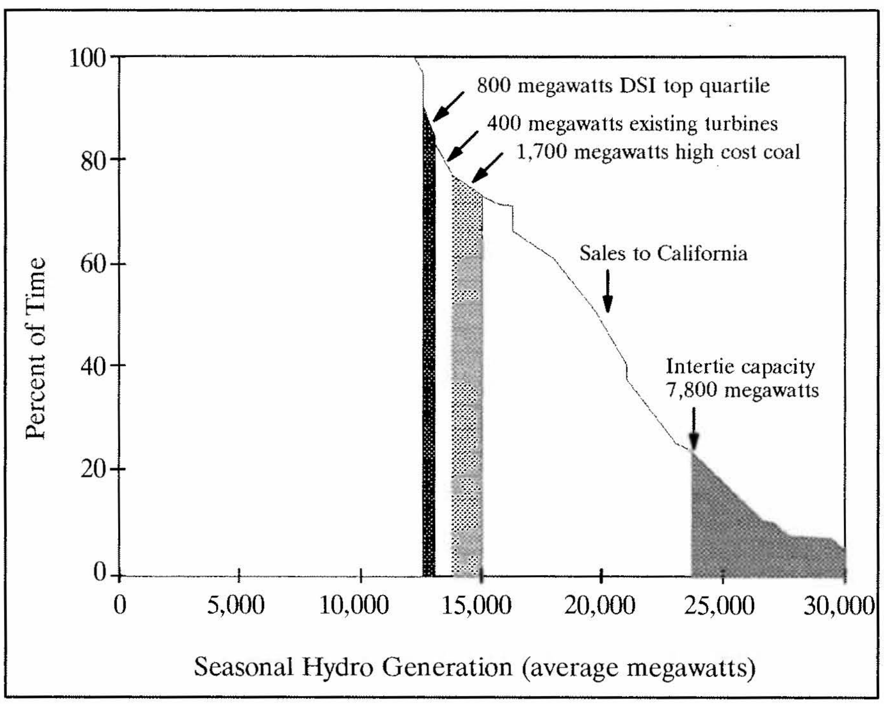
Nonfirm Energy Availability

Figure 8-17
Probability of Nonfirm Energy Availability



Nonfirm Energy Uses

Figure 8-18
Duration Curve of Nonfirm Energy and Uses



The second use of nonfirm energy is to displace Northwest thermal plants. Existing combustion turbines on investor-owned utility systems can be displaced (shut down), using cheaper nonfirm energy from the utilities' 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 anticipated 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 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. The curve in this figure illustrates the benefits of combined-cycle turbines compared with coal gasification plants, as a function of total installed energy. The curve was constructed by comparing studies that included 1,000 megawatts of turbine energy to those with 1,000 megawatts of coal energy, then 2,000 megawatts and so forth. The benefit that is plotted is the lower total system cost that occurs by building turbines instead of coal plants. If this curve were to roll over to the right, it would indicate that *additional* units of turbine energy beyond the turning point 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 benefits as the last megawatt of added coal capacity. Each additional megawatt beyond this point would then have negative value, indicated by the downward sloping portion of the curve. The fact that the combined-cycle curve has not rolled over at 4,000 megawatts indicates that the optimum number is beyond that point, given the assumptions in the study. In fact, under the expected gas prices, turbines are more cost-effective than coal gasification plants, even when the turbines are running at full availability (base loaded).

The cost of simple-cycle combustion turbines is based on industrial-grade machines. Based on these costs, it was determined that simple-cycle combustion turbines are not cost-effective at this time, compared to combined-cycle units. Aero-derivative simple-cycle turbines are somewhat less expensive than industrial-grade machines, and it may turn out that they may become a reasonable alternative to the industrial-type turbines used in this analysis. If so, they could 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 a "hybrid" gas price series calculated using 50-percent firm and 50-percent interruptible gas. 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.

The sensitivity to gas prices is shown in Figure 8-20. The Council's high gas price forecast was used for the analysis. As gas prices increase, benefits of using turbines decrease. At 3,000 megawatts of installed energy, benefits drop almost 60 percent. A more important observation to make, however, is that while there is a significant decrease in benefits, turbines are still cost-effective at least up to 3,000 megawatts of installed energy. In fact, the peak of this curve may well be beyond the 4,000 megawatt range, which is well beyond the limits imposed by the Council in recognition of gas supply.

Gas Turbine Cost–Effectiveness

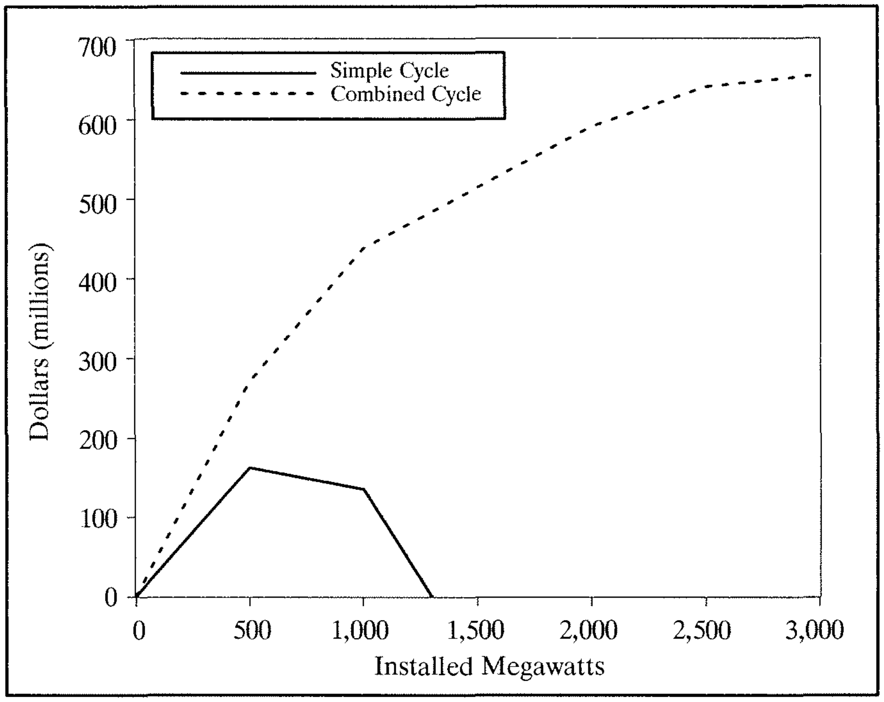


Figure 8–19
Cost–Effectiveness of Gas Turbines Compared to Coal

Gas Price Effects

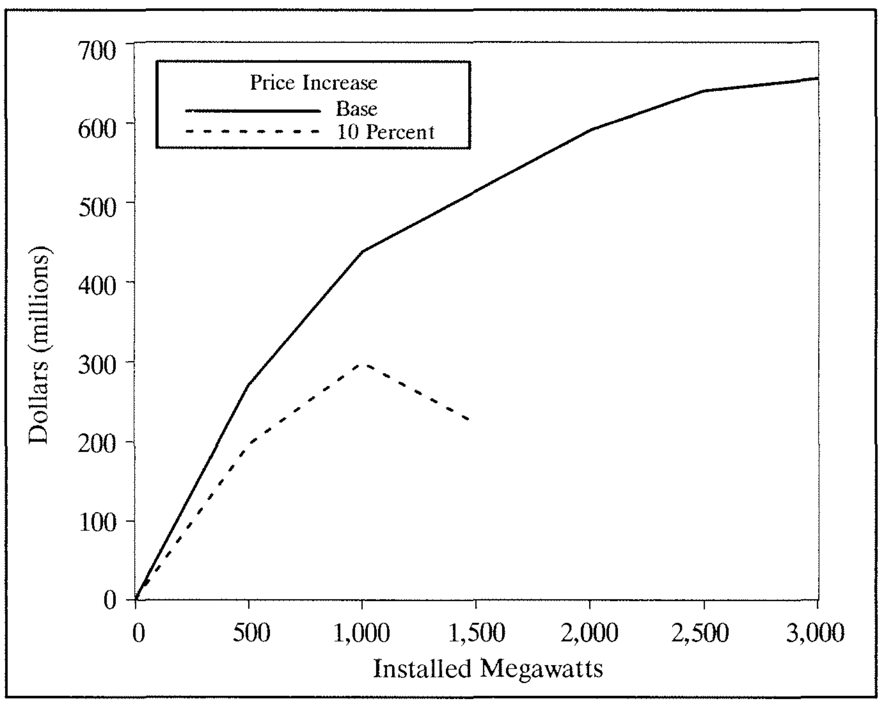


Figure 8–20
Effect of Gas Price on Turbine Cost–Effectiveness

The Council hired an independent contractor to review the Northwest gas supply situation.[24] The contractor 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 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 availability 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, 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. An additional 1,500 megawatts could be subsequently developed, 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 and coal plants. Figure 8-21 shows the results of these studies. Capital cost estimates, as other assumptions in this plan, are surrounded by a band of uncertainty. Even though the Council staff is confident that capital cost estimates are the best they could be, future events, such as new environmental controls, could change those estimates.

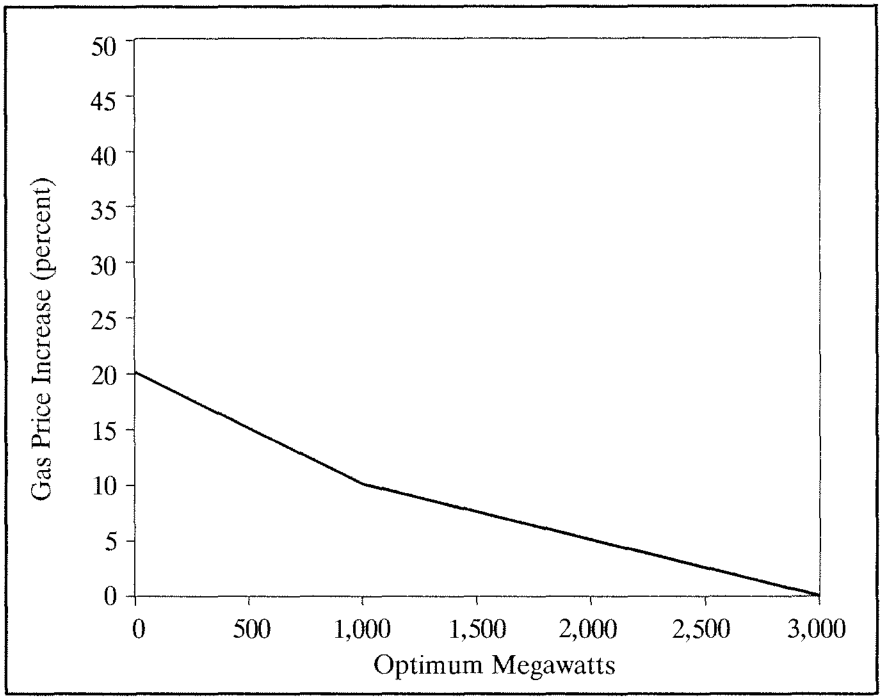
Three alternative cases were examined, including a case where combined-cycle capital costs increase by 25 percent, a case where coal plant capital costs decrease by 25 percent and finally a case where turbine capital costs increase by 25 percent and coal costs decrease 25 percent. The third alternative is highly unlikely to occur especially since a good portion of the coal gasification plant is made up of a combined-cycle turbine. This alternative was included to illustrate how insensitive these cost-effectiveness studies are to capital costs.

Under the first alternative, at 3,000 megawatts of installed energy, net benefits drop nearly 20 percent. When coal capital costs are decreased, a larger impact is observed (since coal capital costs are much greater than turbine costs). Net benefits under the second alternative dropped 60 percent. Finally, when both changes occur, net benefits decrease by over 75 percent.

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

Gas Price Effects

Figure 8-21
Optimum Turbine Megawatts per Gas Price Increase



As the case with the gas price uncertainty, however, even though the net benefits drop significantly, combined-cycle turbines are still cost-effective compared to coal gasification plants at least up to 3,000 megawatts of installed energy. Again, we are well beyond the Council's limit imposed because of gas supply uncertainties.

Capacity Factors

Capacity factors represent the amount of energy that a plant produces in a specific period compared with the amount it was theoretically 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 8-22 shows the incremental capacity factors, as a function of installed energy, for the combined-cycle and coal gasification 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. Figure 8-23 shows the average monthly capacity factor for the two plant types.

The System Analysis Model contains a provision for modeling the impact of sales by BC Hydro on Northwest operations and California sales. In the draft plan, BC Hydro had very little impact on the operation of combined-cycle turbines. Nonfirm energy from BC Hydro did not displace Northwest combined-cycle plants, although it did displace simple-cycle turbines. Given the Council's current set of assumptions about gas prices, studies show that BC Hydro nonfirm energy will displace the operation of Northwest combined-cycle turbines. This is the primary reason that the capacity factors shown in Figures 8-22 and 8-23 are lower for combined-cycle plants than they were in the draft plan. If the interaction of BC Hydro were discontinued, the capacity factors for the combined-cycle turbines would be more like those in the draft plan. This effect can be seen in Figure 8-24. Even under that scenario, which is plausible, combined-cycle turbines would still be cost-effective compared to coal gasification plants.

Capital Cost Effects

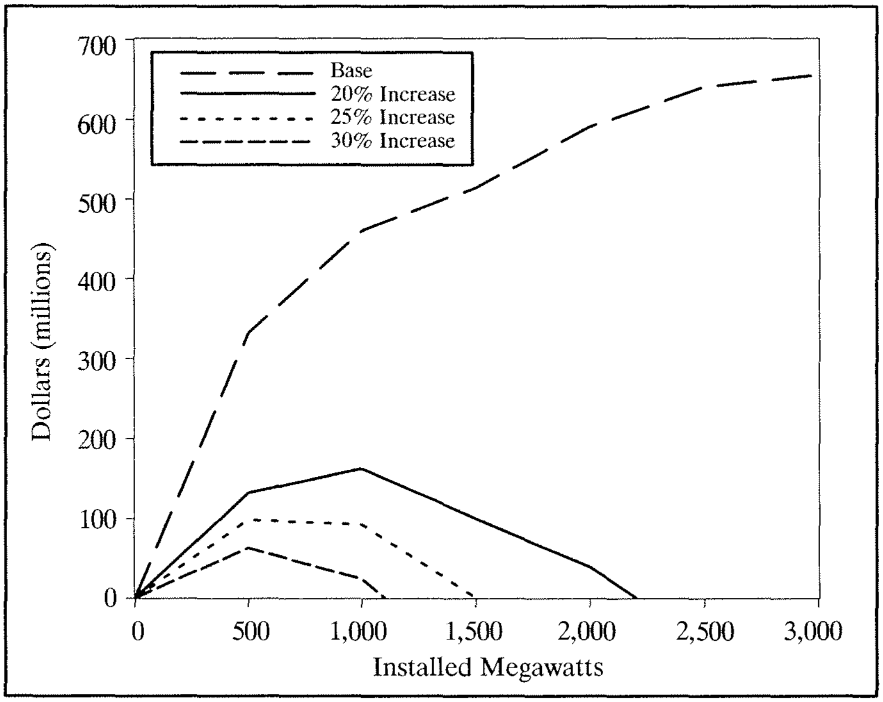


Figure 8-22
Effect of Turbine Capital Cost on Cost-Effectiveness

Capital Cost Effects

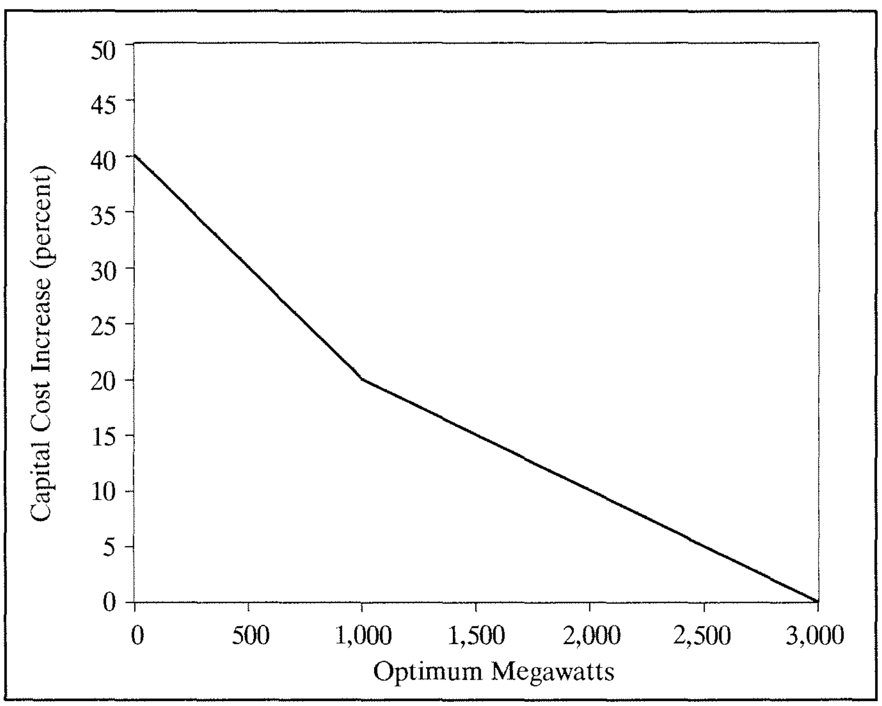


Figure 8-23
Optimum Turbine Megawatts per Capital Cost Increase

Capital Cost Effects

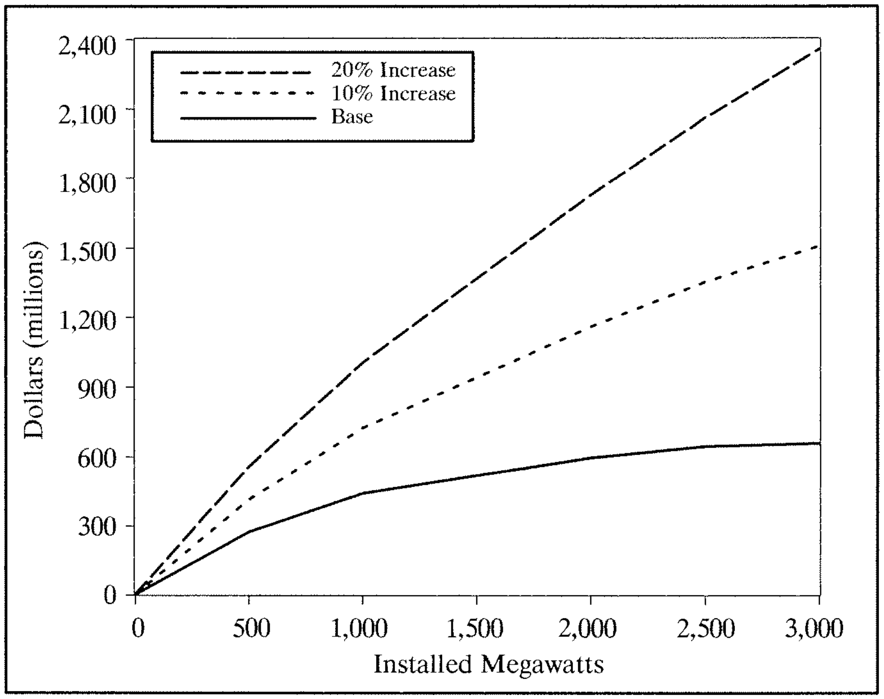


Figure 8–24
Effect of Coal Capital Cost on Cost–Effectiveness

Other Issues

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.

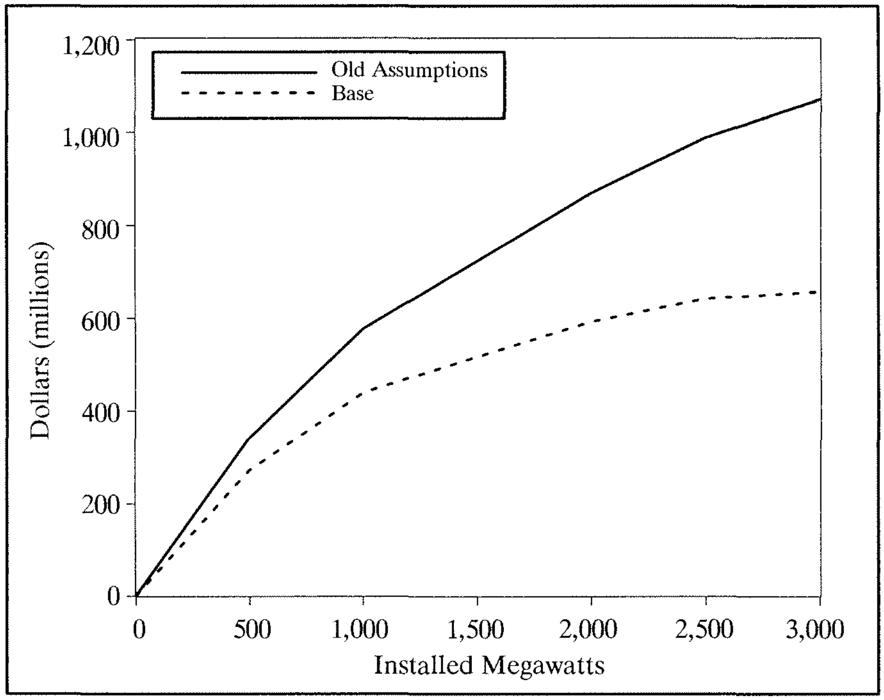
The second potential conflict is in priority of access to nonfirm in the period following January. There may be an argument about the interpretation of the direct service industry power sales contracts on this point, if the turbines are owned by Bonneville. On the other hand, the priority in this period 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 direct service industries' top quartile.

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 8-25 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.

Capital Cost Effects

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



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, since flow levels under the Columbia River Basin Fish and Wildlife Program are considered hard constraints on the hydroelectric system.

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 system operation 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. If the Council determines that future resource operation is posing problems for implementation of the flow levels, the Council will impose further constraints through fish and wildlife program amendments.

Additional flows that cannot be shaped to power operations, such as 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 because they increase 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 the Council's, 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 did not use coal gasification plants and 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. All else equal, the Bonneville studies 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 the Council's 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 the Council study, although the Council study found larger benefits for turbines at comparable megawatt levels. Since the two studies were done with different models and methods, and compared turbines to a different, less expensive coal plant, it is difficult to compare the results precisely.

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.

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. However, the details would likely be subject to disagreement between public and private entities, depending on circumstances.

Other Turbine Resource Values

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 each 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 and uncertainties about financial assistance, program design issues, and consumer or utility willingness to participate.

Another value, 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 area, 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 otherwise be 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 used as the basis of this analysis 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. For example, Bonneville has indicated in its 1990 Resource Program that it believes that 500 megawatts of backup could be available from extraregional purchase arrangements.

Also, Northwest utilities currently have declared only about 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, three times their declared level. Current limitations are based on existing fuel contracts, site–specific limitations and utility operating desires. However, this extra in–region capability potentially could be part of the new combustion turbine energy this plan describes as cost–effective.

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 8–26 summarizes the results of the study. Conversions of additional 500–megawatt increments of firm load were 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 had the conversion been negotiated as a scheduled resource.

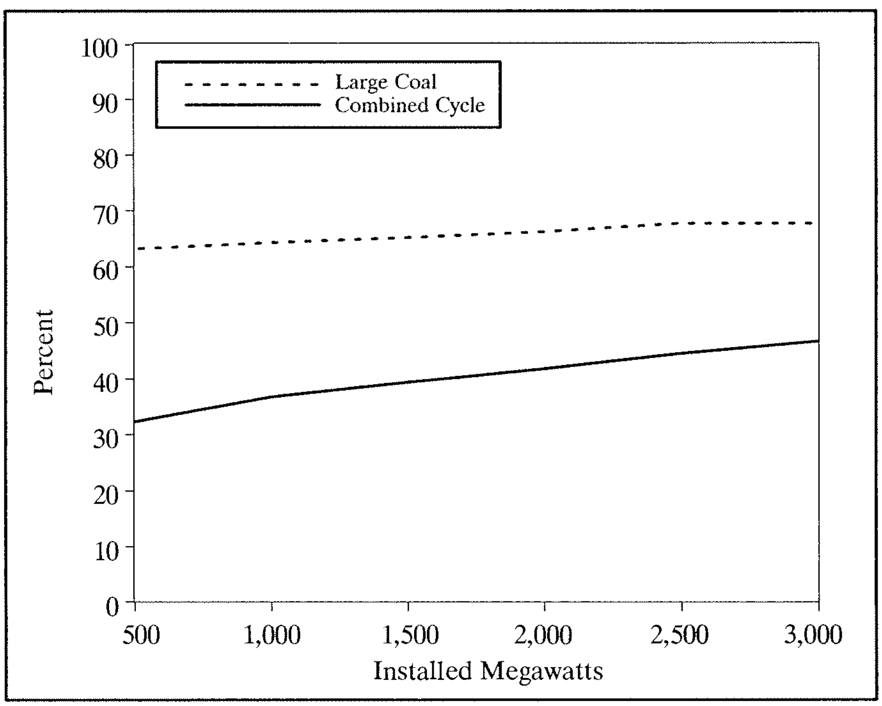
Because of these provisions for scheduling the conversion from firm loads to nonfirm loads, these studies are not directly comparable to the previously described Council studies examining the cost-effectiveness of gas combustion turbines and combined-cycle plants. The earlier studies compared coal plants 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 as, for example, in the low load cases where additional resources are not needed.

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 extraregional sales, as the nonfirm is diverted to interruptible load service rather than extraregional sales. Secondly, 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 8-26, show that the regional benefits increase 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.

Capacity Factor

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



Extraregional Exchanges

Extraregional 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 relative, 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 nonfirm strategies analysis, a comparison was made between two systems, one that met load growth with coal gasification plants and the other, that 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.

Aside from the resources used for comparison (combustion turbine and coal gasification plants) only existing thermal resources were used, along with a set of loads that yielded a balanced load resource condition through the end of the study period. To perform the analysis, an arbitrary increase to 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 comparison was made for load increases up to 4,000 average megawatts in increments of 1,000 megawatts. Resources used to meet these load increases were constructed to exactly match the load growth.

Conservation and renewable resources were assumed to increase over time to a level of about 1,900 average megawatts by the year 2011. That corresponds to the level of development for a medium growth scenario. 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 end-effect problem exists due to the assumed lives of the two resources being compared. Because the new resources were assumed to be built in September 1999, their operation would extend 18 years beyond the study horizon in SAM. 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 38 years.

Natural Gas and Fuel Oil Price Forecasts

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 such as 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.

The Council's natural gas price forecasts are shown in Table 8-30 and fuel oil price forecasts in Table 8-31. Interruptible gas prices follow residual fuel oil prices through the study period. Prices begin at $2.51 per million Btu in 1990, and escalate over the planning period at an annual average rate of 3.5 percent. This is compared to 1.8 percent in the 1986 plan. One reason for the higher average rate of escalation in this plan are the lower gas prices early in the planning period. These resulted from the natural gas surplus of the late 1980s.

Firm gas prices follow interruptible prices, but at a higher level, reflecting the additional costs of firm service. Prices begin at $3.82 per million Btu in 1990, with an overall annual rate of escalation over the 20-year planning period of 2.1 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 begins at $3.16 in 1990 and escalates at an average annual rate of 2.7 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. The cost of coal-derived synthetic gas may set a ceiling on natural gas prices for utility applications.

Distillate Fuel Oil

Distillate (No. 2) fuel oil is used to fire boilers, simple-cycle and combined-cycle combustion turbines, and diesel generators. It can substitute for natural gas in these applications, but under equilibrium price conditions generally commands a premium price relative to natural gas, because it can be transported and stored more easily. For this reason, in the Pacific Northwest, utility use of distillate fuel oil is limited to back-up and start-up fuels and for combustion turbine and reciprocating engine-generator fuel where 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.

The Council's fuel oil price forecasts are shown in Table 8-31. Distillate prices are forecast to begin at $4.87 per million Btu in 1990. 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 1995, distillate prices are forecast to escalate through the balance of the planning period. The average annual rate of escalation over the 20-year period is 1.9 percent, the same rate forecast 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 $3.15 per million Btu, and decline slightly through 1995, shown in Table 8-31. Beginning in 1996, real prices begin to escalate through the end of the study period. The average annual rate of escalation through the 20-year study period is 2.4 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.

Table 8–30
Natural Gas Price Forecast (1990 Dollars)

Heat Value	1,021 Btu/SCF (HHV)[a]	1,021 Btu/SCF (HHV)[a]	1,021 Btu/SCF (HHV)[a]
Delivery	Pacific Northwest Site	Pacific Northwest Site	Pacific Northwest Site
Transport	Pipeline	Pipeline	Pipeline
Contract	Interruptible	Firm	Hybrid[b]
Variable Cost ($/MMBtu)			
▪ 1990	$2.51	$3.82	$3.16
▪ 1991	$2.53	$3.78	$3.16
▪ 1992	$2.55	$3.75	$3.15
▪ 1993	$2.58	$3.71	$3.14
▪ 1994	$2.60	$3.71	$3.16
▪ 1995	$2.63	$3.68	$3.15
▪ 1996	$2.87	$3.91	$3.39
▪ 1997	$3.13	$4.14	$3.63
▪ 1998	$3.41	$4.37	$3.89
▪ 1999	$3.73	$4.60	$4.16
▪ 2000	$4.07	$4.90	$4.48
▪ 2001	$4.18	$4.98	$4.58
▪ 2002	$4.30	$5.13	$4.72
▪ 2003	$4.43	$5.24	$4.83
▪ 2004	$4.55	$5.38	$4.97
▪ 2005	$4.68	$5.52	$5.10
▪ 2006	$4.75	$5.57	$5.16
▪ 2007	$4.81	$5.62	$5.22
▪ 2008	$4.88	$5.70	$5.29
▪ 2009	$4.95	$5.73	$5.35
▪ 2010	$5.02	$5.83	$5.42
Average Annual Escalation (1988–2007)	3.5%	2.1%	2.7%

[a] HHV—Higher Heat Value.

[b] Fifty percent firm, 50 percent interruptible.

Table 8-31
Fuel Oil Price Forecast (1990 Dollars)

	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]
Delivery	Pacific Northwest Site	Pacific Northwest Site
Transport	Rail or Barge	Rail or Barge
Purchase	Spot	Spot
Variable Cost ($/MMBtu)		
▪ 1990	$3.15	$4.87
▪ 1991	$3.11	$4.87
▪ 1992	$3.07	$4.77
▪ 1993	$3.03	$4.77
▪ 1994	$2.99	$4.66
▪ 1995	$2.96	$4.66
▪ 1996	$3.15	$4.87
▪ 1997	$3.37	$5.09
▪ 1998	$3.59	$5.42
▪ 1999	$3.83	$5.63
▪ 2000	$4.09	$5.96
▪ 2001	$4.20	$6.07
▪ 2002	$4.32	$6.28
▪ 2003	$4.45	$6.39
▪ 2004	$4.58	$6.50
▪ 2005	$4.71	$6.72
▪ 2006	$4.77	$6.72
▪ 2007	$4.84	$6.82
▪ 2008	$4.90	$6.93
▪ 2009	$4.97	$7.04
▪ 2010	$5.04	$7.04
Average Annual Escalation (1988-2007)	2.4%	1.9%

[a] HHV—High Heating Value.

Representative Gas-Fired Power Plants

Plant operating data and cost assumptions were based on representative simple-cycle and combined-cycle power plants.

Simple-Cycle Combustion Turbine

The superior performance record for heavy duty units and their potential for conversion to more efficient combined-cycle configuration led the Council to choose heavy-duty "industrial-grade" units as its representative combustion-turbine technology. However, other designs might be better suited for specific applications. For example, an aircraft-derivative, steam-injected unit might be the choice when later conversion to combined-cycle configuration was not expected.

The General Electric MS7001F combustion turbine is the basis for the Council's estimates of representative combustion turbine cost and performance. This machine operates at higher combustion temperatures and therefore greater efficiency than earlier designs. The first MS7001F was recently delivered to Virginia Power as the first phase of a possible gasification, combined-cycle power plant. Orders for additional units have been placed.

Cost estimates are based on a hypothetical representative plant consisting of twin combustion turbines installed near Hermiston, in eastern Oregon. The plant includes site improvements, weather enclosure with overhead crane, a switchyard, a two-mile gas pipeline spur and 10 miles of transmission line linking the unit with the grid. The lengths of gas pipeline and transmission line required for an actual installation are, of course, site-dependent.

The representative combustion turbine cost, performance and other planning assumptions are summarized in Table 8-32.

Table 8-32
Cost and Performance Characteristics of Natural Gas-Fired Power Plants (1990 Dollars)

	278-Megawatt Simple-Cycle Combustion Turbine	420-Megawatt Combined-Cycle Combustion Turbine
Plant Configuration	Two 139-Megawatt Units	One 420-Megawatt Unit[a]
Rated Capacity (MW/unit)	278	419
Peak Capacity (MW/unit)	152	452
Equivalent Annual Availability (%)	85%	83%
Heat Rate (Btu/kWh)	11,480	7,620
Siting and Licensing Cost ($/kW)	$62[b]	$41[b]
Siting and Licensing Hold Cost ($/kW/yr.)	$2.50[b]	$1.80[b]
Construction Cost ($/kW)[c]	$660[b]	$766[b]
Fixed O&M Cost ($/kW/yr.)[d]	$2.20	$5.80
Variable O&M Cost (mills/kWh)	0.2	0.4
Siting and Licensing Lead Time (months)	48[b]	48[b]
Construction Lead Time (months)[e]	24[f]	36
Service Life (years)	30	30
Reference Energy Costs (mills/kWh)		
▪ Levelized Real	6.2	4.7
▪ Levelized Nominal (1990 in-service)	12.3	9.3

NOTE: Further details regarding these cost and performance characteristics are supplied in Appendix 8-A.

[a] Two 139 megawatt GE MS7001 combustion turbines, one heat recovery steam generator and one 141 megawatt steam turbine-generator.

[b] Costs and schedule are those estimated for obtaining site and licenses for a "gasifier-ready" plant. Lead time and costs for a plant intended for natural gas use only would be shorter (see Appendix 8-A).

[c] "Overnight" cost (excludes interest during construction).

[d] Includes post-operational capital replacement and decommissioning costs.

[e] Includes engineering, procurement and construction.

[f] To first unit of two-unit project.

Combined-Cycle Combustion Turbine

The General Electric STAG 207F combined-cycle plant is the basis for the Council's estimates of representative combined-cycle combustion turbine cost and performance. This plant uses two MS7001F combustion turbines, one heat-recovery steam generator and one steam turbine generator.

Cost estimates were based on a hypothetical representative power plant consisting of twin combined-cycle plants also installed near Hermiston, Oregon. The plant includes site improvements, weather enclosure with overhead crane for the combustion turbines, water supply, cooling towers, a switchyard, a two-mile gas pipeline spur and 10 miles of transmission line linking the plant with the grid. Included in the cost estimates are land and facilities allowing the unit to be converted to coal gasification, if necessary.

The cost, performance and other planning assumptions for the representative combined-cycle combustion turbine are summarized in Table 8-32.

Reference Energy Cost

Reference levelized energy costs for the two representative gas-fired power plants were calculated using the project development assumptions described in the introduction to this chapter. Because of the ability of these plants to supply dependable capacity, capital costs were amortized over the full equivalent availability. The resulting levelized power costs are shown in Table 8-32. Note that these costs do not include the effects of possible displacement by nonfirm hydropower or other resources. Because these plants are fully dispatchable, these plants could be displaced by any dispatchable resource having lower variable costs of operation. Because the variable operating costs of these plants, especially the simple-cycle combustion turbine, are relatively high, it is likely that they may be displaced by low cost nonfirm hydropower when available. Thus, the melded cost of the resulting power will be lower than the representative "stand-alone" costs in Table 8-32.

Planning Assumptions

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

Conclusions

The Council's study showed that, with expected gas prices, combined-cycle generation is more cost-effective than that from coal gasification plants, even when the turbines are running at full availability. However, this result is sensitive to gas prices. Under a high gas price scenario, combined-cycle turbines are no longer cost-effective at full availability. Under this scenario they are cost-effective only when used in conjunction with nonfirm hydro energy. Even in this case, Council studies show that at least 3,000 megawatts of combined-cycle generation can be used to firm the Northwest's nonfirm energy cost-effectively compared to coal gasification plants.

The future price and availability of natural gas 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 portfolio to 1,000 megawatts before the year 2000 and to 1,500 additional megawatts after that.

Table 8–33
Hydrofirming Resource Planning Assumptions (1990 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)	48[a]	48[a]
Probability of Siting and Licensing 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 (%/yr.)[b]	8/41/51	8/41/51
Siting and Licensing Cost ($/kW)	$41[a]	$41[a]
Siting and Licensing Hold Cost ($/kW/yr.)	$1.80[a]	$1.80[a]
Construction Cost ($/kW)	$766[a]	$766[a]
Fixed Fuel Cost ($/kW/yr.)	$0.00	$0.00
Variable Fuel Cost (mills/kWh)	24.1	24.1
Fixed OMR&D Cost ($/kW/yr.)[c]	$5.80	$5.80
Variable O&M Cost (mills/kWh)	0.4	0.4
Earliest Service	1998	2000
Peak Development Rate (units/yr.)	1	1
Operating Life (years)	30	30
Real Escalation Rates (%/yr.)		
▪ Capital Costs	0%	0%
▪ Fuel Costs	2.8% (average)	2.8% (average)
▪ O&M Costs	0%	0%

a "Gasifier ready" site and plant design.

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

c Includes operation, maintenance, post-operational capital replacement and decommissioning costs.

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 a long-term, permanent high-level waste repository 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 about 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's expected production is 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 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's expected production is 711 average megawatts of energy. WNP-2 is owned and operated by the Supply System. The output (project capability) of WNP-2 is 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 and if other non-technical issues can be resolved.

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 would 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 is 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 would 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 would 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 is 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, the capability of the investor-owned utility share of WNP-3, subject to 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 has never been resumed. 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 could be completed and operated. 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.[25]

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, the ability to maintain permits and licenses required for future construction and operation, and other financial and policy concerns.

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 (2006). 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, key aspects of physical preservations—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. But, replacement of technically obsolete equipment, such as computer control systems, with state-of-the-art equipment should lead to improved plant performance.

Preservation Financing

With preservation of the plants demonstrated, continued preservation of 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 eased the pressure on Bonneville to discontinue to preservation funding.

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, the plant's owners; 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 state 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.

25. Under the WNP-3 settlement, Bonneville is obligated to pay the property taxes that are due to Grays Harbor 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.

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's "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 waste waters 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 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 Commission 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 that might affect costs. These requirements are believed to increase costs-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. The capital cost escalation rate assumed for WNP-1 and WNP-3 in this plan is intended to capture these unknown, but, probable, cost increases.

Completion Issues

WNP-1 and WNP-3 have no value as regional power sources unless the plants can be completed and operated. Resumption of construction requires resolution of a number of major issues. But, in view of the favorable experience with improved construction management procedures implemented prior to suspension of WNP-3 construction, if resumed, construction should go more smoothly than in the past.

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 not trivial, but neither is it trivial to site a new coal-fired power 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 that could significantly affect 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 in restarting a completed Savannah River reactor after a "permanent" shutdown. The Department of Energy concluded that such a restart was a major action, and they prepared a full EIS.

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, and preparing the 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, purchasers of bonds issued to resume construction face some additional risk of court-ordered project delays and 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 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. Snohomish 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.

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 Number 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. Unlike WNP-1, WNP-3 has no neighboring plant with an approved emergency response plan.

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.

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

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 Environmental Impact Statement	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-Bonneville Contract Management Issues	1 year
Council 6(c) Process for WNP-3	1 year
Nuclear Regulatory Commission Operating License Approval	1 to 2 years

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 plants 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 2 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 that was included in the 1986 Power Plan. Adjusted to 1990 dollars, the estimated costs to complete WNP-1 and WNP-3 used in the 1986 plan were $1,338 per kilowatt and $1,248 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 1990 dollars, these estimated construction costs to complete the plants were $1,286 per kilowatt for WNP-1 and $1,125 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. Current estimates of costs-to-complete are $1,401 per kilowatt for WNP-1 and $1,235 per kilowatt for WNP-3, in 1990 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.

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. The Nuclear Regulatory Commission has reviewed the Supply System study and conclusions. Its position is that the Supply System has included all known information in its study and has done so adequately. However, the Commission noted that the United States Geological Survey is continuing studies in Washington and Oregon at this time. New information uncovered in these studies could be germane to WNP-3. The Commission further recommended that the Supply System follow closely the ongoing studies as they relate to the Pacific Northwest and the Satsop site, in particular.

If the findings and conclusions of the Supply System 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 to be constructed as twin plants, sharing common facilities where feasible. Similarly, WNP-3 and WNP-5 were to be 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 re-establish 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.

Termination Issues

Termination of WNP-1 and/or WNP-3 presents its own set of issues. Resolution of these issues is necessary for well-informed decisions on the future of the plants.

Decision Process

The legal agreements that control these projects give little guidance as to what process should be followed if a decision is made to terminate the projects. In the absence of unanimity among the participants, possibly lengthy litigation could result.

Disposal of Assets

In the event of termination, the salvageable assets can be disposed of by either of two methods, under the bond resolutions. The first method requires simultaneous payment of cash into the Bond Fund sufficient to retire all the project's bonds. The net-billing agreements requiring payments to the Supply System may satisfy this requirement, but if not, the requirement is an obstacle to asset disposal. The second method described in the Bond Resolution requires proceeds from asset disposal to be deposited in the Construction Fund, which might preclude them from being used to pay for site restoration.

Assuming that the disposal of assets is carried out, the assets could either be sold as separate components to various buyers, or as partially completed power plants to buyers planning to complete construction and generate electricity. The latter path might be expected to bring a higher price, but might also take more time, since it would likely involve a complex package of construction, operation and power sales contracts. This was the approach used at the termination of WNP-4 and WNP-5. The Supply System first attempted to sell the plants, or the plant systems, as an entity. The plants were later parted out after the first approach proved unsuccessful.

Effect on Outstanding Bonds

There is some concern that termination of the plants could be interpreted as an Event of Default, making the projects' bonds due. The counsels of the Supply System, Bonneville and the bond underwriters are all of the opinion that termination would not be an Event of Default. This issue has not disappeared as a result of refinancing the higher-cost project bonds.

Site Restoration

The Washington Energy Facility Site Evaluation Council (EFSEC) establishes requirements for restoring sites. EFSEC has not determined the level of restoration that would be required if WNP-1 and/or WNP-3 were terminated, but four alternative levels have been identified as possible. These levels range from a fence with "No Trespassing" signs and 24-hour security to total demolition and burial of all structures with recontouring and replanting the entire site. The estimated costs of restoration range from about $3 million (1986 dollars) for WNP-1 and $4 million for WNP-3 (with continuing costs of $0.6 million and $0.9 million per year, respectively) for the simplest level to $80 million for WNP-1 and $78 million for WNP-3 (with continuing costs of $0.1 million per year for each plant) for the most thorough level.[26]

Restoration costs would increase if termination occurred after fuel loading. In this case, the tasks involved in restoration would include many (but not all) of those required for decommissioning. Restoration costs, therefore, would move closer to decommissioning costs, but would not be as high.

Suitability of Sites for Other Generating Plants

The sites of WNP-1 and WNP-3 have some advantages as sites for other electricity generation facilities. Transmission links are already in place; the WNP-3 site has the extra advantage of access to the Puget Sound area independent of the heavily loaded cross-Cascades transmission system. Both sites have been approved as sites for electricity generation and would seem to be good candidates as sites for other generation facilities. The WNP-1 site is subject to inversion layers in winter, making air pollution a special concern.

26. Bonneville Power Administration, *WNP-1 and -3 Study, 1987 Resource Strategy*, May 1987.

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.

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 dry-cask storage systems, 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. These costs have not been included in the estimated costs to complete and operate these plants.

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.

Operation and Maintenance Costs

The Council's 1986 analysis assumed that operation 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 rate of escalation of nuclear operation, maintenance and replacement costs has peaked, and subsequently 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 operation and maintenance cost escalation will decline from 3.5 percent annually in 1986 to zero percent 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 operation and maintenance 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.

The challenge facing the Council is to predict the operation 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 was plotted separately for both Babcock and Wilcox plants and Combustion Engineering plants. These curves, shown in Figures 8-27 and 8-28, 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.[27]

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.

Prospects for Completion of WNP-1 and WNP-3

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. The portfolio analysis done for this plan assumes the plants are financed by the current owners.

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.

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. Table 8-37 presents the technical and cost assumptions and Table 8-38 shows current ownership of the plants.

The financial assumptions used for assessing WNP-1 and WNP-3 are consistent with those used elsewhere in this plan for the respective classes of plant owners except for the cost of debt financing. As described earlier, 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 bond issues in general and WNP-1 and WNP-3 in particular.

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27. For the Babcock and Wilcox curve, data for Three Mile Island 2 was excluded as was 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.

Table 8-35
Historical Annual Equivalent Availability Factors
Babcock and Wilcox and Combustion Engineering Nuclear Power Plants[a]

Plant	Ave. 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	13	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 Point 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 b, but excluding the years 1980-1985 for TMI #1 and excluding the years 1986-88 for Rancho Seco. The argument for exclusion of this data is that events leading to shutdowns occurring during these years 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.

Equivalent Availability Probability

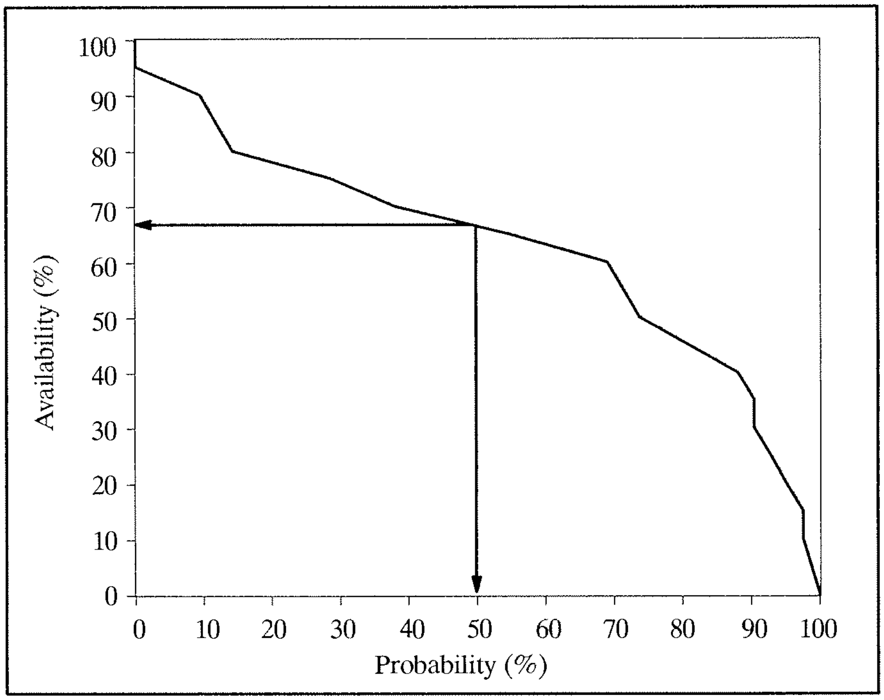

Figure 8-27
Probability of Realizing Minimum Equivalent Availability Factors for Babcock and Wilcox Plants

Equivalent Availability Probability

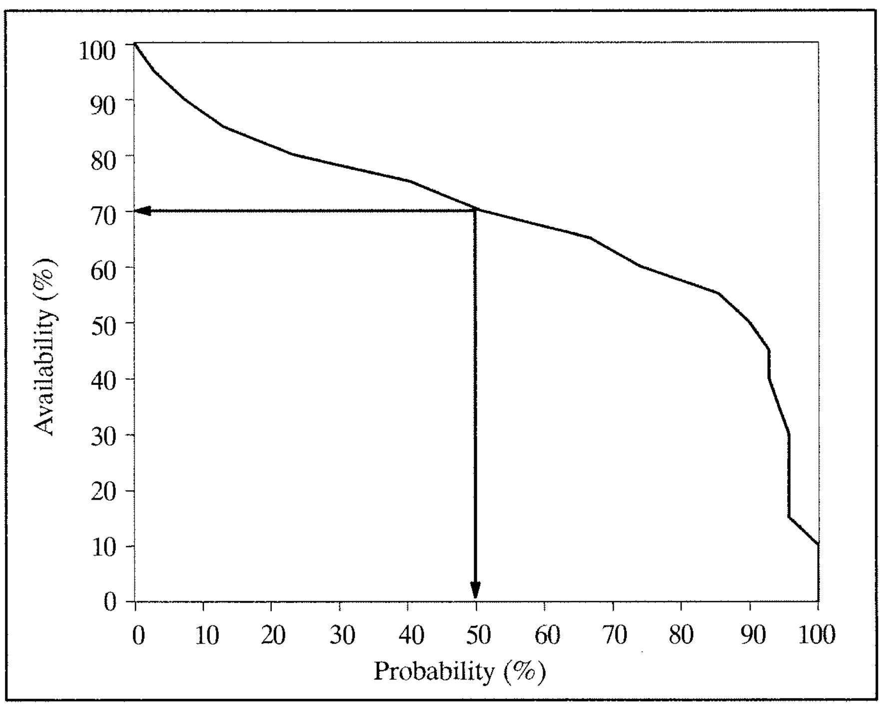

Figure 8-28
Probability of Realizing Minimum Equivalent Availability Factors for Combustion Engineering Plants

Table 8-36
Reference Energy Costs for WNP-1 and WNP-3 (1990 Dollars)

	Real (cents/kWh)	Nominal (cents/kWh)
WNP-1	4.7	9.3
WNP-3	4.3	8.5

Conclusions: WNP-1 and WNP-3

WNP-1, if completed and operated at the costs of Table 8-37, could produce about 812 average megawatts of energy at costs estimated to be about 9.3 cents[28] per kilowatt-hour and WNP-3 could produce about 868 average megawatts of energy at an estimated cost of 8.5 cents[29] per kilowatt-hour. These costs are less than the estimated 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 contributor to global warming concerns.[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 polarized. 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. This would involve resolving the less expensive issues first, before committing significant effort to problems that will be more expensive to address.

New Nuclear Fission Technology

The nuclear industry and the federal government are 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.

28. Reference nominal levelized costs for a hypothetical 1990 in-service date.

29. Ibid.

30. 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 (1990 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
Pre-construction Lead Time (months)[a]	36	36
Probability of Siting and Licensing Success (%)	90	90
Preservation Shelf Life (years)	Indefinite	Indefinite
Probability of Hold Success (%)	90	90
Construction Lead Time (months)[b]	60	60
Construction Cash Flow (%/yr.)	c	d
Pre-construction Cost ($/kW)	$17	$19
Preservation Hold Cost ($/kW/yr.)	$4.60	$5.10
Construction Cost ($/kW)[e]	$1,401	$1,235
Fixed Fuel Cost ($/kW/yr.)	$0.00	$0.00
Variable Fuel Cost (mills/kWh)	5.9	6.5
Fixed OMR&D Cost ($/kW/yr.)[f]	$92.30	$93.40
Variable O&M Cost (mills/kWh)	1.0	1.0
Earliest Service	1999	1999
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	0% to 1993, 1% thereafter	
▪ O&M Costs	3% in 1988, declining to 0% by 2000	

a Resolution of institutional and financial issues.

b Remobilization and completion.

c Projected construction cash flow for WNP-1 is 11/23/30/24/12%.

d Projected construction cash flow for WNP-3 is 4/24/33/29/10%.

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

f Includes fixed operation, maintenance, post-operational capital replacement and decommissioning costs.

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%

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. The models and vendors 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.

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. 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.

Table 8-39
Large Evolutionary Nuclear Plants—Planned Characteristics

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 ($/kW)	Not Available
Construction Cost, exclusive of AFUDC ($/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

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.[31]

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

31. 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.

some release of these materials, since U.S. fuel enrichment plants are powered by utility systems using coal-fired generation.

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[32] 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[33] 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.

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.

32. 10 Code of Federal Regulations 20 *Standards for Protection Against Radiation.*

33. 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.

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 high level waste 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.

Recently, the appropriateness of this site has been questioned, putting the schedule back once again. 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 be easier to build and achieve better 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. Few of these proposals have achieved commercial viability. 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. In addition, 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:[34]

- 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.

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.

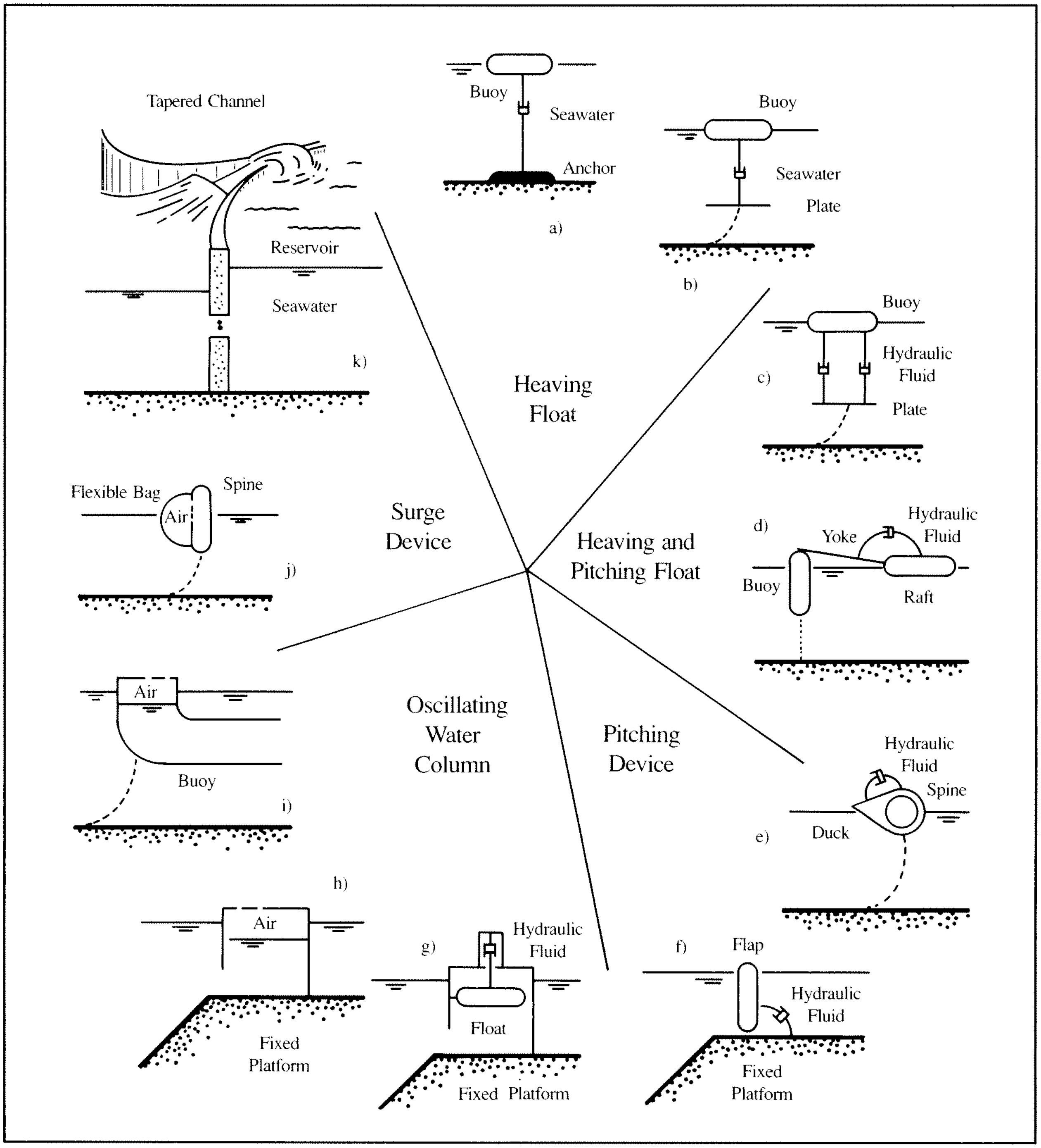
Wave Power Technology

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 8-29 illustrates the principal designs showing promise for commercial application.

34. 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 are examined separately by the Council.

Wave Power Plants

Figure 8–29
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 8-29(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 8-29(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 8-29(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 8-29(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 8-29(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 8-29(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, depends 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 8-29(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 8-29(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 8-29(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 8-29(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 8-29(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 would have to be carefully planned 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 could ultimately be 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, re-establishing a wave field behind the plants. Sections of the near-shore environment may change from the reduced wave action, which can 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 wind speed 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. A plus is that wave power in the Pacific Northwest peaks in winter when loads also peak. 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 theoretical 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 devices sponsored by the British government, 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 Table 8-40.

Assuming investor-owned utility development, the straight-spine SEA Clam would produce energy at a cost of about $1.11 per kilowatt-hour in levelized 1990 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-megawatt 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 is not a strong function of wave length. The amount of materials and fabrication per unit capacity, can be relatively smaller with the longer wave lengths of the North Pacific.

Table 8–40
Cost and Performance Characteristics for Ocean Wave Power Units (1990 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	$7,500/kW	$1,832/kW
Operation and Maintenance Cost	$74/kW/yr.	$124/kW/yr.
Operating Life	30 years	30 years

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.[35] The resulting costs and plant characteristics are shown in the right-hand column of Table 8–40. Assuming investor-owned utility development, this plant would produce energy at a cost of about 22 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, 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

35. Costs from Table 3 in Hagerman and Heller, 1988, (Baltic Sea Hose Pump) were escalated to 1990 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.

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

The technology is at a conceptual stage of development, but there appear to be no insurmountable technical obstacles to methane production using marine biomass in the Pacific Northwest.

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 $9 to $27 per cubic meter. This is equivalent to $4.42 to $13.81 per million Btu[36] in 1990 dollars. For comparison, the cost of firm contract natural gas is forecast by the Council to range from $4.86 per million Btu in 1989 to $5.62 per million Btu in 2007 (in 1990 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 concepts 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 8-30, 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.

36. Btu (British Thermal Unit) is the amount of heat required to raise one pound of water one degree Fahrenheit.

Osmotic Hydropower Plant

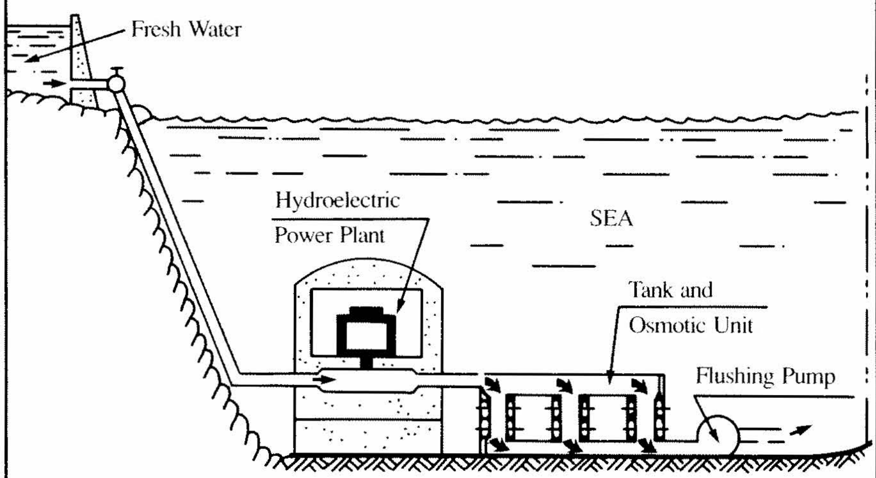


Figure 8-30
Reali Submarine Osmotic Hydropower Plant (EPRI 1986)

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 would greatly 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 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 southern Puget Sound (see Table 8-41). The best Northwest sites have only slightly more than half the mean tidal range of potentially feasible North American sites. Because the power production potential of a tidal electric plant is a function of the square of the mean tidal range, energy from the best Northwest tides (assuming geographically suitable sites were available) could be expected to cost about three times that of the proposed plant at Half Moon Cove, Maine.

Cost and Performance of Tidal Power Plants

The cost of tidal electric power plants is site-specific. The cost example in Table 8-42, for a proposed plant at Half Moon Cove, is illustrative only, because no comparable sites exist in the Pacific Northwest.

Assuming investor-owned utility development, this plant would produce energy at a cost of about 28 cents per kilowatt-hour in levelized nominal 1990 dollars.

Table 8–41
Mean Tidal Range at Various Oregon and Washington Bays, Inlets and Estuaries (feet)

Site	Mean Tidal Range (feet)	Source
Alsea Bay, Oregon	5.8	From Percy, et al., 1974
Chetco Bay, Oregon	5.1	From Percy, et al., 1974
Coos Bay, Oregon	5.6	From NOAA, 1988
Coquille Bay, Oregon	5.2	From Percy, et al., 1974
Elk River Estuary, Oregon	~5	From Percy, et al., 1974
Nehalem Bay, Oregon	5.9	From Percy, et al., 1974
Nestucca Bay, Oregon	5.8	From Percy, et al., 1974
Netarts Bay, Oregon	5.7	From Percy, et al., 1974
Pistol River Estuary, Oregon	~5	From Percy, et al., 1974
Rogue River Estuary, Oregon	4.9	From Percy, et al., 1974
Salmon Bay, Oregon	5.8	From Percy, et al., 1974
Sand Lake, Oregon	5.7	From Percy, et al., 1974
Siletz Bay, Oregon	5.0	From Percy, et al., 1974
Siuslaw Bay, Oregon	5.2	From Percy, et al., 1974
Sixes River Estuary, Oregon	~5	From Percy, et al., 1974
Tillamook Bay, Oregon	5.7	From Percy, et al., 1974
Umpqua Bay, Oregon	5.1	From Percy, et al., 1974
Winchuck River Estuary, Oregon	~5	From Percy, et al., 1974
Yaquina Bay (Newport), Oregon	6.0	From NOAA, 1988
Youngs Bay, Oregon	6.7	From NOAA, 1988
Blind Bay, Shaw Island, Washington	4.5	From NOAA, 1985a
Budd Inlet (Olympia), Washington	10.5	From NOAA, 1988
Commencement Bay (Tacoma), Washington	8.1	From NOAA, 1988
Cornet Bay, Whidbey Island, Washington	6.6	From NOAA, 1985a
Drayton Harbor, Washington	5.9	From NOAA, 1985a
Eagle Harbor, Bainbridge Island, Washington	7.8	From NOAA, 1985b

Table 8–41 (cont.)
Mean Tidal Range at Various Oregon and Washington Bays, Inlets and Estuaries (feet)

Site	Mean Tidal Range (feet)	Source
Elliot Bay (Seattle), Washington	7.7	From NOAA, 1988
Fisherman Bay, Lopez Island, Washington	4.4	From NOAA, 1985a
Gig Harbor, Washington	8.2	From NOAA, 1985b
Grays Harbor (Aberdeen), Washington	7.9	From NOAA, 1988
Henderson Bay, Washington	9.4	From NOAA, 1985b
Liberty Bay, Washington	8.0	From NOAA, 1985b
Oakland Bay (Shelton), Washington	10.6	From NOAA, 1985b
Penn Cove, Whidbey Island, Washington	7.8	From NOAA, 1985a
Port Gardner (Everett), Washington	7.4	From NOAA, 1988
Port Ludlow, Washington	6.4	From NOAA, 1985b
Port Townsend, Washington	5.2	From NOAA, 1988
Quartermaster Harbor, Vashon Island, Washington	8.2	From NOAA, 1985b
Roche Harbor, San Juan Island, Washington	4.4	From NOAA, 1985a
Sinclair Inlet, Washington	8.0	From NOAA, 1985b
The Great Bend (Hood Canal), Washington	8.1	From NOAA, 1985b
West Sound, Orcas Island, Washington	4.5	From NOAA, 1985a
Willapa Bay (South Bend), Washington	7.8	From NOAA, 1988

Table 8–42
Cost and Performance Characteristics for a 12–Megawatt Tidal Hydroelectric Power Plant
(EPRI, 1986, Escalated to 1990 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	$4,175/kW
Operation and Maintenance Cost	$18.30/kW/yr.
Operating Life	30 years

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.

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 8-31), 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.

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.

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.

Water Current Turbine

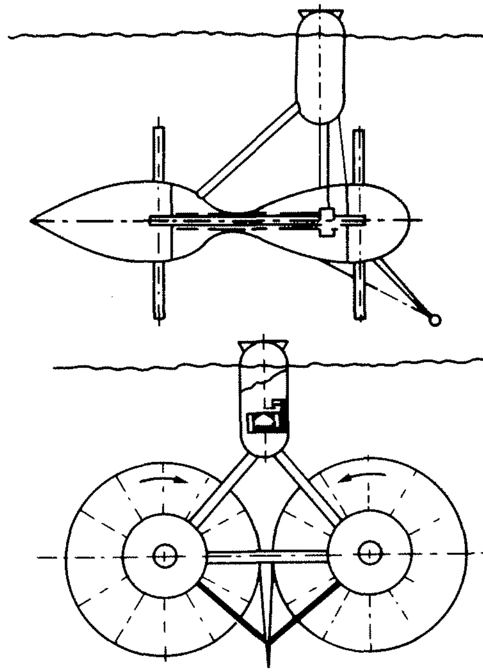


Figure 8-31
Heronemus Water Current Turbine (EPRI 1986)

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.

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 8-32 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.

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 the U.S. Department of Energy's Seacoast Test Facility in Hawaii indicates 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 of equivalent size.

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°C to 7°C (41°F to 45°F) (Cocke, 1980). This suggests that gradients range from 0°C to 12°C (0°F 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. This example is illustrative only, because no suitable temperature gradients are found in the Northwest.

Assuming investor-owned utility development, this plant would produce energy at a cost of about 53 cents per kilowatt-hour in levelized nominal dollars.

Other estimates of the costs of OTEC power plants have ranged as low as $4,300 per kilowatt. At this cost, an OTEC plant could produce energy at a levelized cost of 21 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.

Conclusions: 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.

OTEC Power Plant

Figure 8-32
Conceptual Layout of a 10-Megawatt Floating OTEC Power Plant (Lennard 1987)

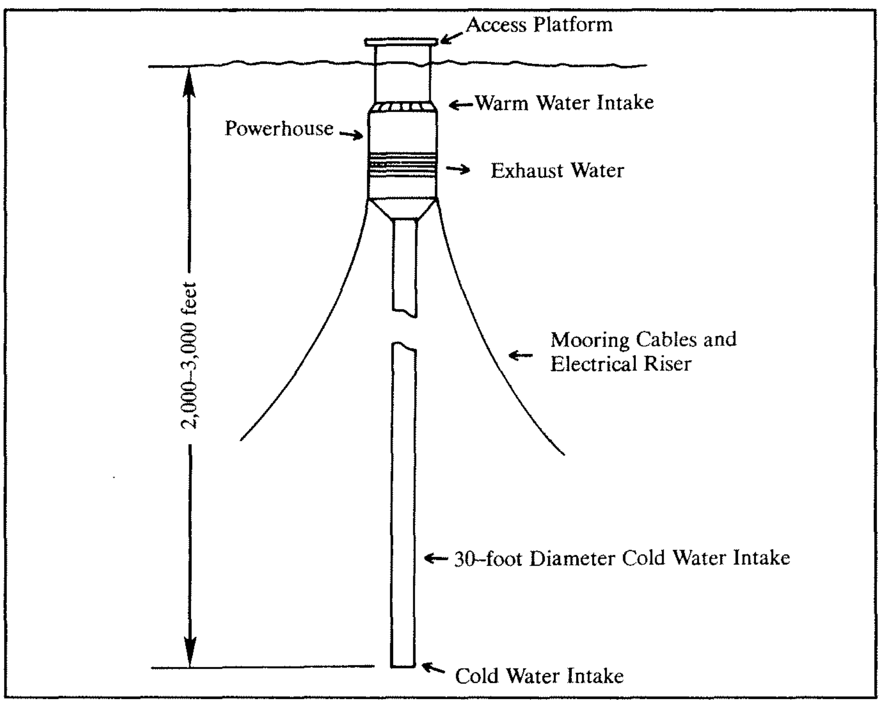


Table 8–44
Cost and Performance Characteristics for a 40–Megawatt OTEC Power Plant (EPRI, 1986, Escalated to 1990 Dollars)

Type	Closed–Cycle, Shore–Based OTEC
Location	Kahe Point, Hawaii
Number of Units	1 @ 45.8 MW each
Rated Capacity	45.8 MW (net)
Availability	80%
Capacity Factor	68%
Construction Cost	$13,754/kW
Operation and Maintenance Cost	$210/kW/yr.
Operating Life	30 years

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Solar

This section reviews solar technologies that produce electricity. Direct applications of solar energy are addressed in Volume II, Chapter 7.

The sun's energy must be gathered over a relatively large area and then 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 efficiently convert it to electricity. 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 intermittent[37] 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 back-up 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 its 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 such as electric range fences represent a sizeable market for photovoltaics. Consumer products such as solar calculators, watches, yard lights, and a long list of other applications also 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 solar resource confirmation agenda described 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

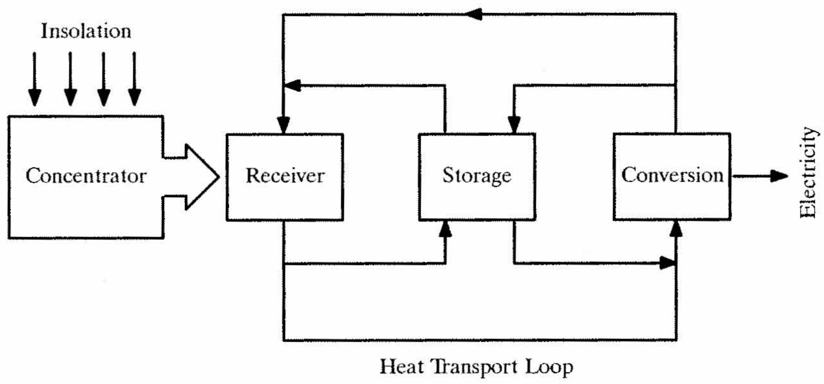
Although solar-thermal technologies are quite different in their particulars, all solar thermal technologies have similar characteristics. Each of the technologies has collectors to concentrate solar energy, receivers to heat a working fluid, and conversion units to convert the heat of the working fluid to electricity. Many solar-thermal designs incorporate an energy storage facility to smooth and extend the availability of energy from the plant. This is shown in Figure 8-33.

The challenge for solar-thermal plants is to collect and concentrate the fuel. Therefore, concentrating collectors characterized by large surface area, are used to capture an adequate amount of the total resource. The collectors have 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.

37. 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.

Solar Thermal System

Figure 8-33
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 8–34.

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. Water is vaporized in the receiver and used to drive a steam turbine–generator. Alternatively, a working fluid such as molten salt is heated in the receiver and used to transfer the heat to a thermal storage device. Heat from the thermal storage device is used to produce steam in a steam generator; this steam is used to drive a steam turbine–generator. Because this design incorporates thermal storage, a constant or dispatchable power output can be obtained.

A 10–megawatt capacity central receiver, Solar–One, 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.

Plans to retrofit Solar–One with molten salt heat transfer fluid and improved thermal storage capability are being developed by Sandia National Laboratories and a consortium of utilities.

Parabolic Troughs

The parabolic trough solar–thermal technology is the technology seeing greatest commercial use. This technology is less efficient at higher temperatures[38] than other solar–thermal 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 horizontally. 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

38. 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.

Solar Thermal Technologies

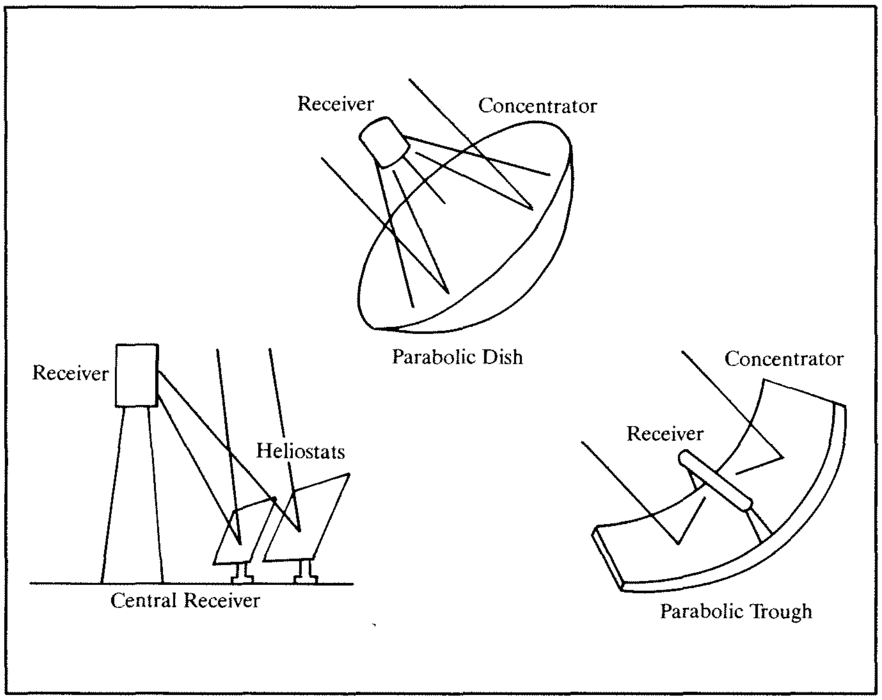


Figure 8-34
Solar Thermal Technologies

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.

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.

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° Fahrenheit and passed through a heat exchanger to create superheated steam for the turbine generator.[39] 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.[40] In California, the plants are constrained by state law to produce no more than 25 percent of their total output using natural gas.[41] This constraint results in about 70 percent of the plant's output coming from solar energy.

Luz is currently operating the world's 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).

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 converting natural gas to electricity, the efficiency is about 37 to 38 percent.

39. *Luz in Brief.* Luz International Limited, September 1989.

40. Although the Luz plants are used in California to supply capacity, they could be used as base-load plants. If they were, gas backup of solar would be conceptually similar to gas backup of nonfirm hydro.

41. California has adopted the Federal Energy Regulatory Policy Act 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.

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 8-34, 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. 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.[42] These are:

42. 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).

The Solar Total Energy Project: This project is located in Shenandoah, Georgia, and includes 114 parabolic dishes with 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.

Solar Plant I: 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.

Osage City, Kansas: This project contains an engine connected directly to each receiver. The design uses an organic Rankine cycle.[43] The system has a total field capacity of 100 kilowatts.

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 from incident radiation. 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 form a direct current. The direct current is 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 8-35). 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 inverter if it is to be converted to alternating current.

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 uses lenses to focus and intensify the sunlight on the photovoltaic cells. These cells require a tracking system to follow the sun. 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

43. A Rankine-cycle device is a type of 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.

Crystalline Silicon Cell

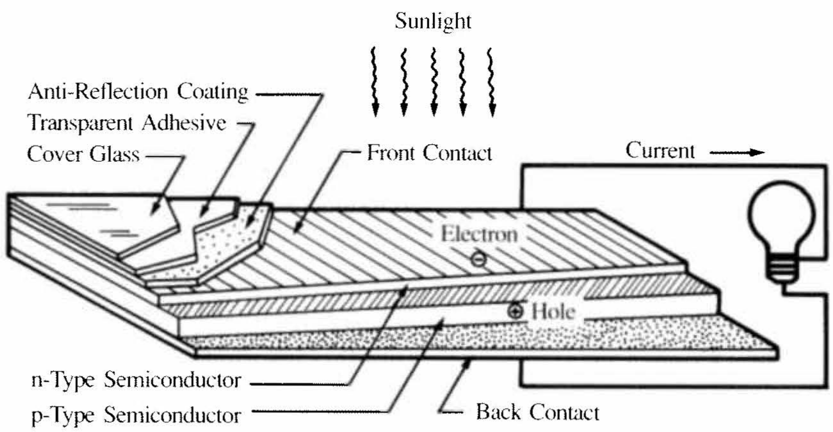


Figure 8–35
Typical Photovoltaic Cell

applications, island communities, and in consumer products, such as watches and calculators. A recent EPRI study (EPRI, 1991) identified 69 different potentially cost-effective applications of photovoltaics for utility systems. Many of these applications are being implemented.

These applications demonstrate 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 control-station 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 8-36 shows the progress of photovoltaics from 1982 to 1987, the last year for which documented data is 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.

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

Photovoltaic Progress

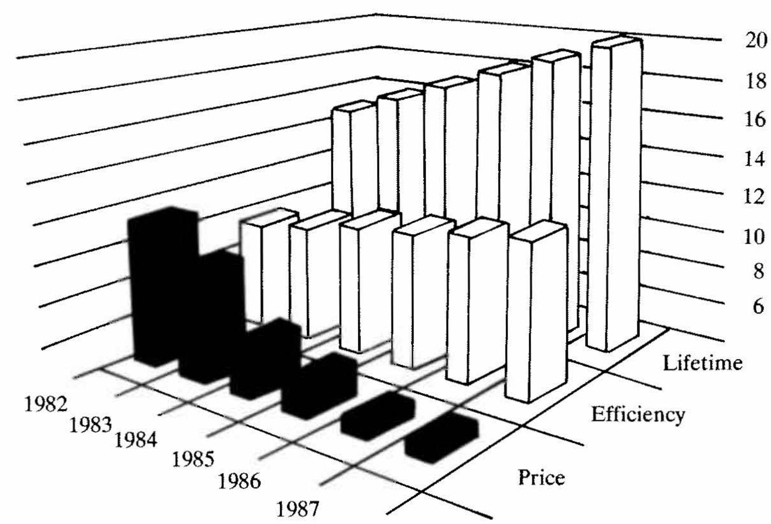


Figure 8-36
Solar Photovoltaic Progress (1982–1987)

lowest was 18 percent, with a variance of about 6 percent.[44] 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 plant being cost-effective or not.

Although a regional solar insolation data collection effort was underway for several years in the late 1970s and early 1980s, this effort has been greatly scaled back, and the existing regional irradiation data base is not deemed to be adequate for a long-term assessment of the region's solar potential. However, solar experts 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 in 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. The good news is that there would be plenty of land available. The bad news is that a plant in these locations 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 face transmission siting and cost constraints.

44. *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 requirements can be reduced 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. Future Luz parabolic trough plants, are expected to use water instead of oil 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 megajoules,[45] 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 8-40).

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 systems. The effects upon terrestrial habitat may, however, be very different than the effects of, for example, the buffer zone around a nuclear power plant. 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.

45. One megajoule is equal to 0.28 kilowatt-hours.

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 other than for periodic cleaning of the collectors. In general, effects on water quality and fish and aquatic ecosystems are likely to be negligible compared to conventional thermal plants.

The indirect effects of solar plant operation on fish and wildlife through interaction with the regional hydropower system remain unstudied. The Council, in the activities plan, calls for the assessment of the synergistic efforts of resource operation.

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 8-37 shows the regional location of the data that has 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 airport, 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, also were 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. 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.

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 8-38 and 8-39. Figure 8-38 shows values on a flat surface facing south and tilted by a number of degrees equal to the latitude of the site. Figure 8-39 shows irradiation on a horizontal surface. The contour lines of constant irradiation levels, shown in megajoules 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 8-38 or 8-39.

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 8-38 and 8-39 reveals that southern Idaho and southeastern Oregon have extremely good solar resources.

Figure 8-40 shows the more promising areas for central-station solar generation in the region, based on estimated irradiation.

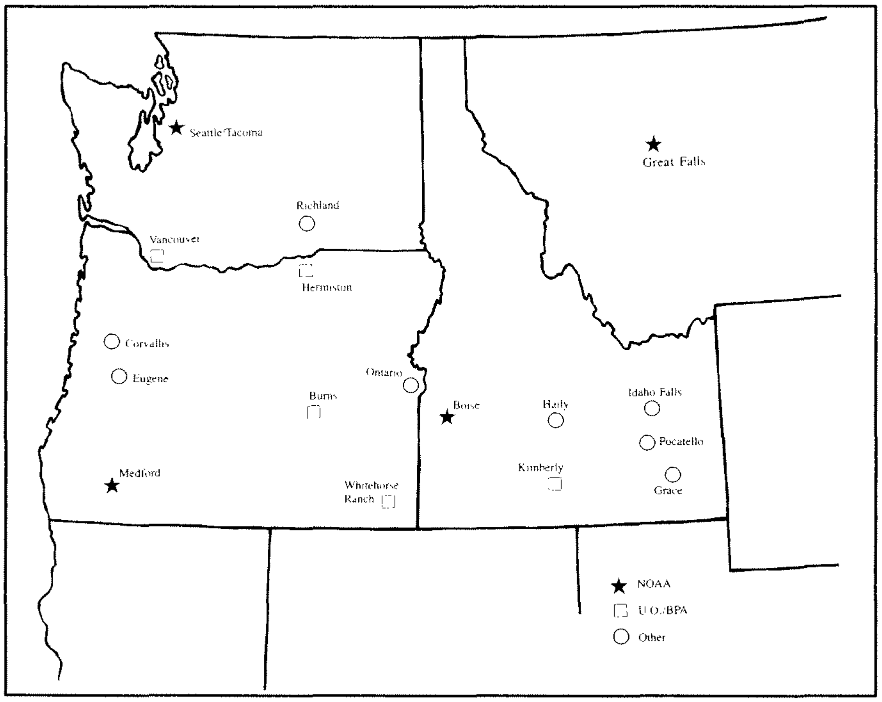
Table 8–46
Northwest Solar Insolation Data Collection Sites

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—Bonneville Power Administration
DOE—U.S. Department of Energy
EWEB—Eugene Water and Electric Board
INEL—Idaho National Engineering Laboratory
NOAA—National Oceanic and Atmospheric Administration
OSU—Oregon State University
PNL—Pacific Northwest Laboratory (Battelle)
PP&L—Pacific Power and Light Company
UO—University of Oregon
USU—Utah State University
WWP—The Washington Water Power Company

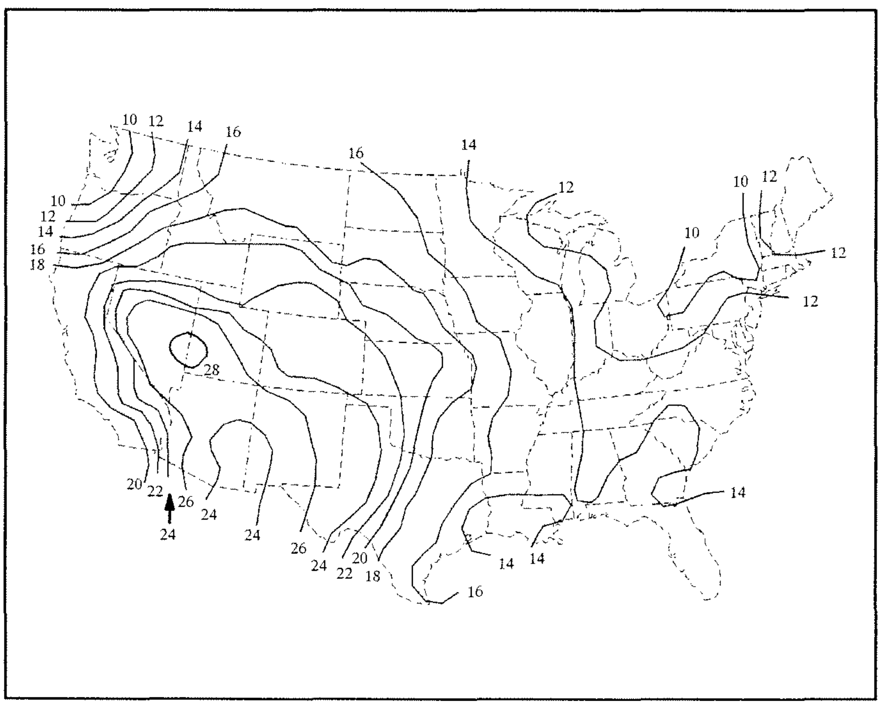
Insolation Monitoring Sites

Figure 8–37
Northwest Insolation Data Monitoring Sites



Total Daily Solar Radiation

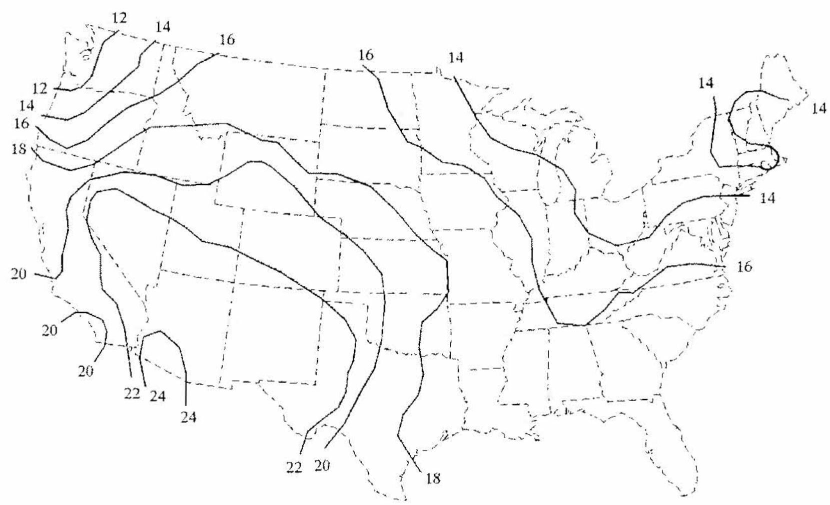
Figure 8–38
Average Daily Total Solar Radiation on a South Facing Surface, Tilt = Latitude (MJ/m^2) (Solar Radiation Resource Atlas of the United States 1981)



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 8–39
Average Daily Direct Normal Solar Radiation (MJ/m^2) (Solar Radiation Resource Atlas of the United States 1981)



Costs and Performance of Solar–Thermal Power Plants

All solar technologies face the same challenge in lowering costs. Solar power plant performance is affected by its own geometric requirements, the clearness of the ambient air, and the orientation of the sun. The trade–offs between efficiency and costs in designing solar plants are numerous. 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 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.

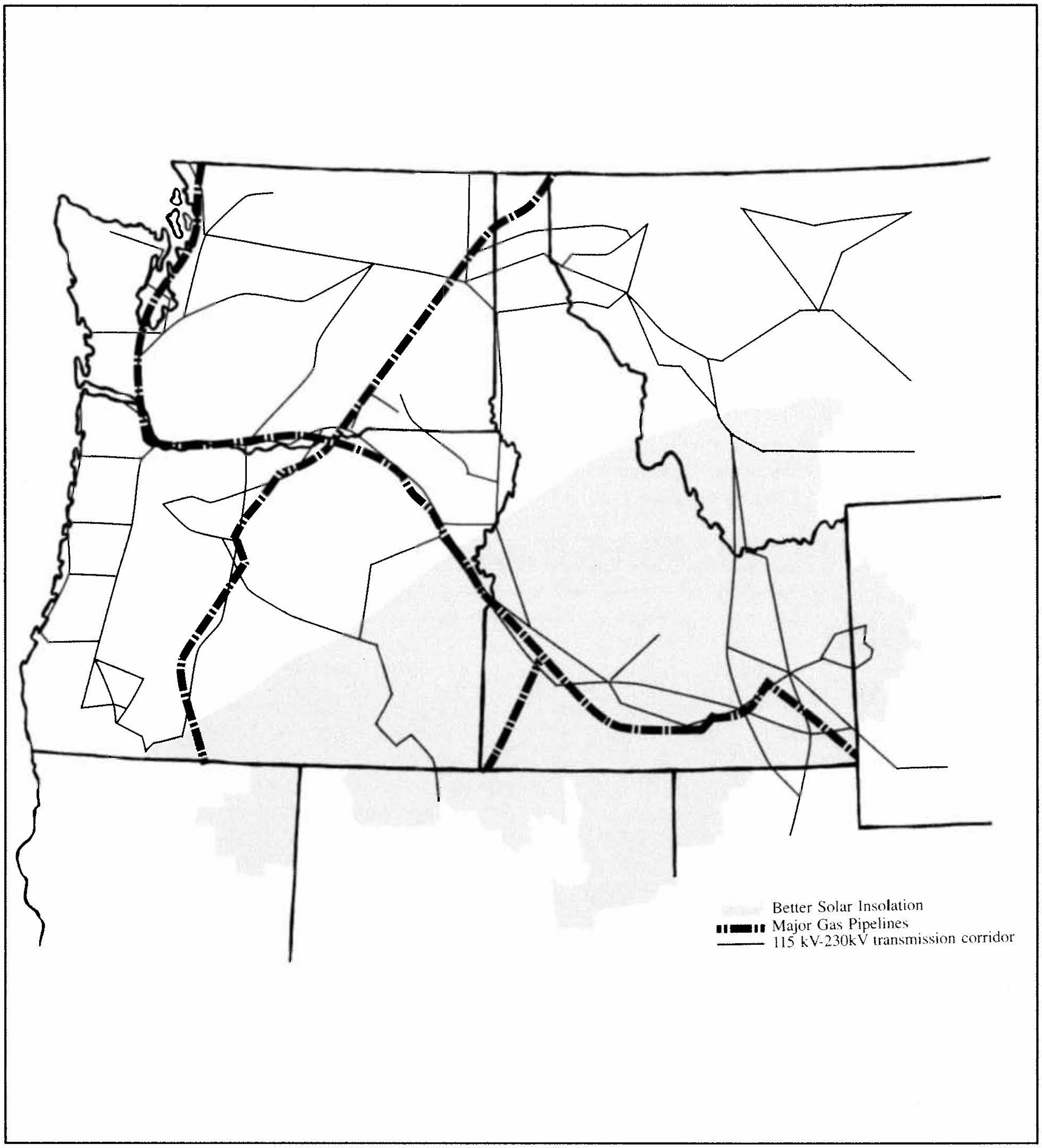
2. Improving the quality and lowering the costs of the reflective area of the collector surface. This requires lowering the construction cost of highly polished and accurate surfaces, which to date have been hard to mass produce, with the exception of the parabolic trough.

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.

Central Solar Plant Sites

Figure 8–40
Promising Areas in the Pacific Northwest for Central Solar Generating Plants



Gas–Hybrid Parabolic Troughs

The overnight capital cost reported for the LUZ California plants 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. But it is important to remember that those cost figures are for current low gas prices and for a plant located in the desert Southwest where there is an excellent solar resource and include the effects of special tax benefits. The Council's assessment of this technology suggests that the costs of a parabolic trough plant located in the Northwest currently would be considerably higher.

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 8–40, 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.

Parabolic Dishes

Cost for parabolic dishes also have dropped rapidly over the last decade. Figure 8–41 shows parabolic dish capital costs from 1980 through 1986 and future target costs. Costs dropped from $13,500 per kilowatt in 1980 to near $8,000 per kilowatt by 1986. The target costs are $1,500 per kilowatt by 1995. The information in Figure 8–41 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.

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. Target costs are $1,500 per kilowatt by 1995 to 2000. This appears to be a difficult target to achieve.

Parabolic Dish Cost

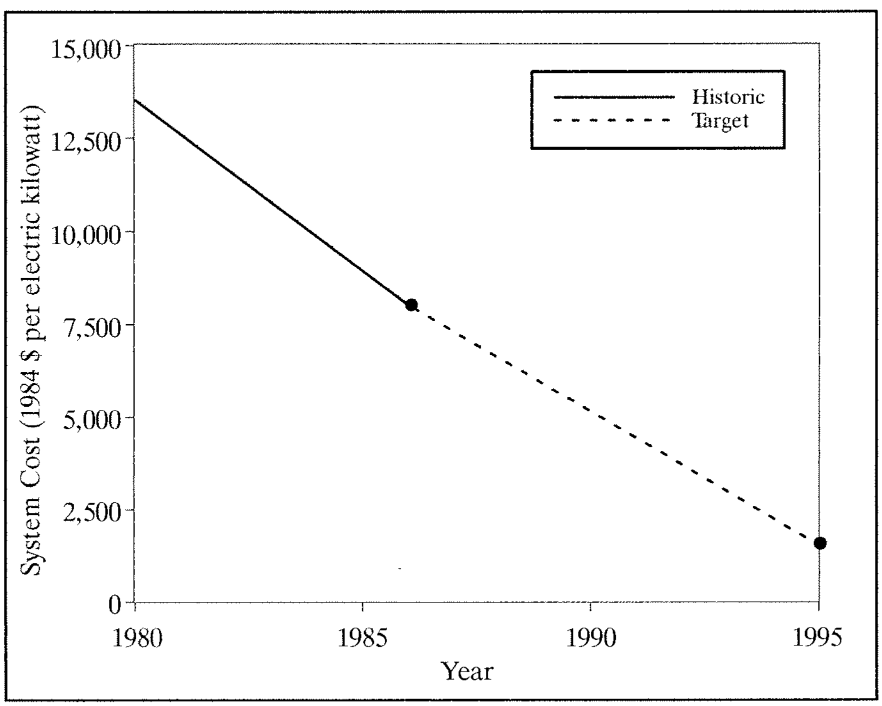


Figure 8–41
Cost Trends and Targets for Parabolic Dishes (Focal–Point Engines)

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.

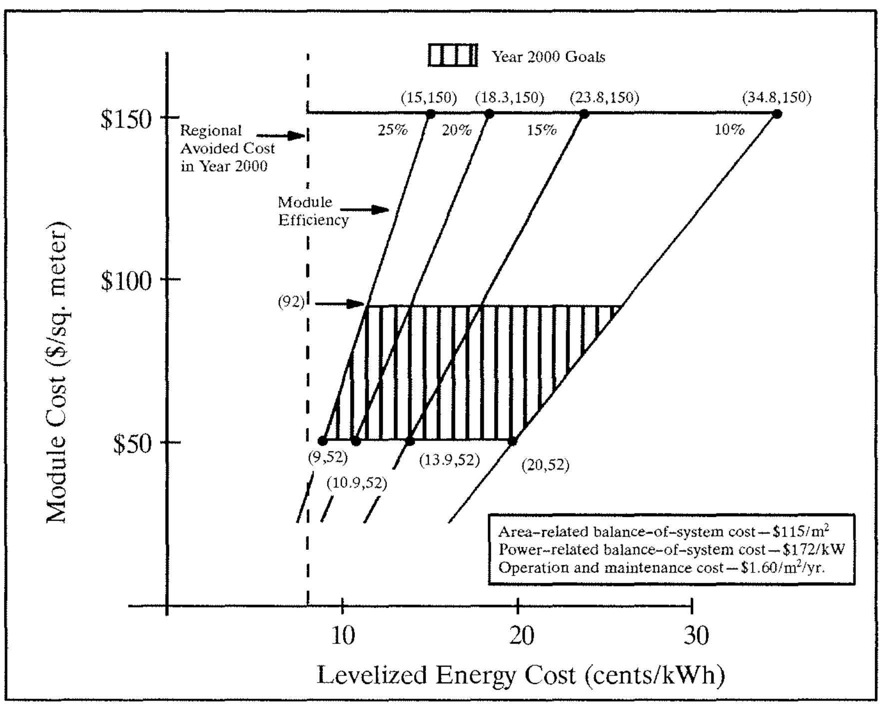
Figures 8-42 and 8-43 show electricity cost goals for selected photovoltaic technologies in cents per kilowatt-hour (nominal dollars) for a range of assumptions related to various component costs.[46] Figure 8-42 shows year 2000 cost goals for flat plate photovoltaic modules with two-axis tracking, in comparison with forecast regional avoided costs. Other flat plate photovoltaic designs (fixed and single-axis tracking) appear to be not cost-effective at this time. Figure 8-43 shows year 2000 cost goals for concentrator photovoltaic systems, also compared to forecast regional avoided costs. 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.[47] At those prices, given the environmental advantages of solar, photovoltaic electricity almost certainly would be competitive.

46. Costs were calculated based on the fundamental solar equations for photovoltaics. The formulas 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 in the calculations shown in Figures 8-42 and 8-43.

47. The targets are for efficiency levels and costs and do not imply specific values for module costs or balance-of-system costs.

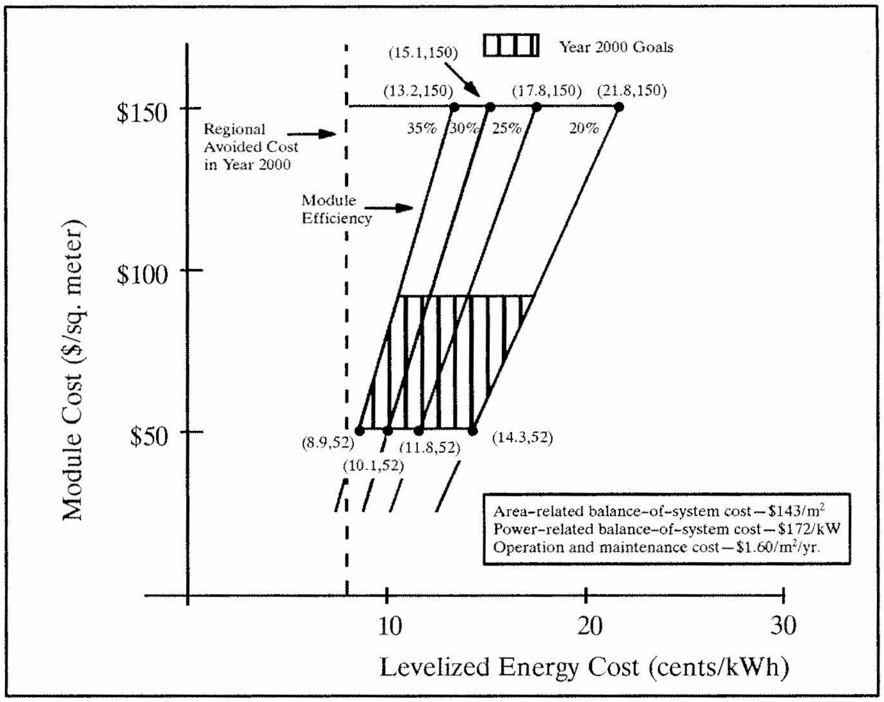
Photovoltaic Flat Plate Goals

Figure 8-42
Photovoltaic Two-Axis Flat Plate Year 2000 Goals (1990 Dollars)



Photovoltaic Concentrator System Goals

Figure 8-43
Photovoltaic Concentrator System Year 2000 Goals (1990 Dollars)



Representative Solar Power Plant

Because the technology is commercially available, this plan uses parabolic trough with supplemental gas-firing as the representative central station solar-electric technology. Because this technology is currently the least-costly of the solar-electric technologies, it serves as a useful benchmark to test the current cost-effectiveness of solar power against competing resources. Furthermore, because of the supplemental gas-firing capability, this technology could conceivably provide additional value to the Northwest electric power system as a hydropower firming resource.

The estimated costs and performance characteristics of the representative Northwest parabolic trough power plant with supplemental gas-firing are shown in Table 8-47. Costs were completed with the assistance of members of the Solar Technical Advisory Panel of the Council's RD&D Advisory Committee. Basic power plant costs have been adjusted to include transmission interconnection costs, supplemental fuel storage and other features making them comparable with other representative power plants used in this plan. The estimated capacity factor for the collector field is from estimates prepared by the Oregon Department of Energy for the 1986 Power Plan, for parabolic trough solar power plants located in southeastern Oregon.

Because of its ability to operate on supplemental gas firing, the plant described on Table 8-47 could integrate well with the Northwest power system. The power plant could be operated on natural gas as a backup to nonfirm hydropower, serving as a hydrofirming resource as described in the "Nonfirm Strategies" section of this chapter. Because the gas heater would presumably be shut down during daylight hours, the availability of the plant for gas-fired hydrofirming would be somewhat more limited than for a stand-alone combustion turbine plant.

In addition to hydrofirming, the gas portion of the plant could serve peak power needs, similar to the existing California LUZ plants.

Conceivably, the plant could be constructed in two stages. The first phase would include the power block and gas heater. This could be followed at a later date by the solar field, if warranted by declining field prices or increases in natural gas prices.

Reference Energy Costs

Reference energy costs were calculated for each of the two phases of the representative parabolic trough solar thermal power plant with supplemental gas firing. In addition, melded costs were calculated for the plant as a whole. The Council's standard financial assumptions, as described in the introduction, were used.

Table 8–47
Cost and Performance of a Parabolic Trough Solar–Thermal Power Plant with Supplemental Gas–Firing (1990 Dollars)

	Power Block and Gas Heater	Collector Field	Total Plant
Rated Capacity (MW)	80	0[a]	80
Peak Capacity (MW)	87	0[a]	87
Equivalent Availability (%)	92	92	92
Heat Rate (Btu/kWh)	9,616	N/A	9,616[b]
Siting and Licensing Cost ($/kw)	5	13[a]	18
Option Hold Cost ($/kw/yr.)	3	0[a]	3
Construction Cost ($/kw)[c]	735	2,636[a]	3,371
Fixed O&M Cost ($/kw/yr.)	32	16[a]	48
Variable O&M Cost (mills/kWh)	0.9	0.9[a]	1.8
Siting and Licensing Lead Time (months)	24	—	24
Construction Lead Time (months)	24[d]	24[e]	24[d]
Operating Life (years)	30	30	30

[a] Incremental value.

[b] Operating on natural gas.

[c] "Overnight" cost (excludes interest during construction).

[d] From equipment order; 12 months required for field work. Equipment order could proceed following one year of siting and licensing activity.

[e] If built as a separate phase.

The first phase, the power block with the gas heater, was assumed to be constructed independently, and operated as a hydrofirming resource with a 30 percent capacity factor. Gas prices were assumed to be the "hybrid" series described in the "Nonfirm Strategies" section of this chapter. The resulting reference energy costs are 17 cents per kilowatt–hour (nominal), with an annual energy production of 24 average megawatts from each 80 megawatt unit. (The comparable levelized energy cost from the Council's representative gas–fired combined–cycle combustion turbine operating at our equivalent capacity factor is 13.5 cents per kilowatt–hour. The difference is largely attributable to the higher efficiency and lower operation and maintenance costs of the combined–cycle plant.)

The second phase would involve addition of the solar collector field. The solar field could be expected to operate the plant at about a 28 percent capacity factor in a southeastern Oregon or southern Idaho location, producing on average, about 22 megawatts of energy. The cost of this incremental energy, considering the incremental costs only of the collector fields, is estimated to be 19.9 cents per kilowatt–hour (nominal).

The melded cost of energy from the plant operating at a 30–percent capacity factor on gas and a 28–percent capacity factor on solar is about 18 cents per kilowatt–hour (nominal).

Comparing these costs to the costs of electricity from new coal generation, about 11.1 to 12.7 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 solar capacity factor (approximately 28 percent) expected. Also (and not considered in the "stand–alone" energy costs described above), in the Northwest, peak solar months occur during the summer, when power needs are low. This tends to lessen the value of the solar resource.[48] If the efficiency of the technology improves or capital costs come down, solar plants may become cost competitive in this region.

48. See the section on resource cost–effectiveness and seasonal benefits in Volume II, Chapter 10.

Planning Assumptions

Because parabolic trough solar-thermal technology is commercially available, though expensive, it was considered for subsequent resource portfolio analysis where the availability of less expensive alternative resources was curtailed. For purposes of analysis, this resource was considered to consist of two blocks, one block consisting of the gas-heater-power block portion of the resource and the second block consisting of the collector field.

Characteristics of these two blocks are summarized in Table 8-48.

Table 8-48
Solar Resource Planning Characteristics

	Solar I Parabolic Trough Power Blocks	Solar II Parabolic Trough Collectors
Total Capacity (MW)	1,600	1,600
Total Firm Energy (MWa)	861	448
Unit Capacity (MW)	80	80
Seasonality	Winter Peaking	Summer Peaking
Dispatchability	Full	Must-run
Siting and Licensing Lead Time (months)	12[a]	12[a]
Probability of Siting and Licensing Success (%)	60%	95%
Siting and Licensing Shelf Life (years)	5	5
Probability of Hold Success (%)	90%	90%
Construction Lead Time (months)	24[b]	24[b]
Construction Cash Flow (%/yr.)	40%/60%	40%/60%
Siting and Licensing Cost ($/kW)	$5	$13
Siting and Licensing Hold Cost ($/kW/yr.)	$3	$0
Construction Cost ($/kW)	$735	$2,636
Fixed Fuel Cost ($/kW/yr.)	$0	$0
Variable Fuel Cost (mills/kWh)	30.4	0.0
Fixed OM&R Cost ($/kW/yr.)[c]	$32	$16
Variable O&M Cost (mills/kWh)	0.9	0.9
Earliest Service	1994	1994
Peak Development Rate (units/yr.)	6	6
Service Life (years)	30	30
Real Escalation Rates (%/yr.)		
▪ Capital Costs	0%	0%
▪ Fuel Costs	2.8%	0%
▪ O&M Costs	0%	0%

[a] To equipment order; total siting and licensing time is 24 months.

[b] From equipment order.

[c] Includes fixed operation, maintenance and post-operational capital replacement costs.

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 solar photovoltaics.

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 photovoltaic technologies and begin work that could lead to a central-station solar photovoltaic project.

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 also 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 could back up the solar resource 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 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, often at 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 remain 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

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" section of this chapter).

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 appear as hydropower project upgrades on the regional hydropower data base and are included in the assessment of new hydropower resources.

Any projects to increase operating head must be consistent with fish and wildlife protection needs.

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. Because of lack of information, 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 latter measures 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 1990 dollars using the Handy-Whitman Index of public utility construction costs. The resulting levelized costs in nominal dollars are shown in Table 8-49. The costs shown in Table 8-49 are based on the full 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 improvement potential are shown in Table 8-49. Currently available measures, including turbine runner replacement and installation of electronic governors can provide about 110 megawatts of energy.

Because of uncertainties regarding cost and feasibility, the measures shown as "promising" in Table 8-49 are not currently considered available for development.

Conclusions: Hydropower Efficiency Improvements

Energy from potential hydropower efficiency improvements is an attractive resource because of its low cost and minimal environmental effects. Improvements in turbine design and operation allowing better operating efficiency may reduce the mortality of fish passing through the turbines.

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. Much of the region's hydropower capacity is controlled by federal agencies, and improvements to these projects are subject to the federal budgeting process. Methods to encourage the upgrades of federal projects should be identified and implemented. Federal hydropower operators 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 8-49. The Council also encourages development and demonstration of advanced technologies leading to further improvements in the efficiency of hydropower units.

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 in the Northwest 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 cost and availability of thermal power plant upgrades is plant-specific, the Council has been reluctant to include generic estimates of regionwide thermal power plant upgrade potential in earlier power plans. But, recently, owners of several of the region's thermal power plants have published assessments of specific upgrades to these facilities. This information has provided the Council with the means to begin compiling estimates of regional thermal upgrade potential.

Tables 8-50 and 8-51 list the thermal plant upgrades for which the Council currently has information adequate to estimate the availability and cost of energy. Though various utility least-cost plans mention possible upgrades to plants other than those listed in Tables 8-50 and 8-51, published information concerning these upgrades is insufficient to support estimates of energy cost and availability.

Of the upgrades listed in Tables 8-50 and 8-51, the Bridger upgrade and the WNP-2 low pressure rotor replacement are underway and included in the estimates of existing resource capability used for this plan. Thus, these are not considered as possible new resources.

The two Beaver upgrades are mutually exclusive. Because Portland General Electric Company cites upgrade 2 as preferable, and because of the lower cost of this more extensive upgrade, the Council has chosen Beaver upgrade 2 for inclusion in the thermal plant upgrade supply curve. This, along with the WNP-2 governor valve upgrade constitutes the Council's thermal plant upgrade supply estimate at this time. Because of the small size of this resource, thermal plant upgrade potential was consolidated into a single resource block for planning purposes (Table 8-52). The characteristics of the melded block of resource principally reflect those of gas-fired combined-cycle plants because of the dominance of this resource block by the Beaver upgrade 2.

The Council encourages owners and operators of the region's thermal power plants to fully explore the potential for cost-effective upgrades to these facilities, and to implement these improvements when cost-effective.

Table 8–49
Availability and Cost of Hydropower Efficiency Improvements (1990 Dollars)

	Energy (MWa)		
	Available	Promising	Cost (cents/kWh)[a]
Turbine Runner Upgrades (Kaplan)	—	—	3.3
Turbine Runner Upgrades (Frances)	—	—	1.7
Total Energy, Turbine Runner Upgrades	85		
Electronic Governors	27	—	0.1
Windage Loss Reduction	—	46	1.1
Generator Rewinding	—	5	116.7
Solid-state Exciters	—	9	14.4
High-efficiency Transformers	—	—	2.3
Improved Water Usage	—	23	0.3[b]
Station-Service: High-Efficiency Motors	—	—	10.8
Station-Service: Improved Powerhouse Lighting	—	—	11.8
Station-Service: Improved Powerhouse HVAC	—	—	79.8
Total Station Service Upgrades		17	

[a] Reference levelized life-cycle costs, nominal dollars. Based on a hypothetical 1990 in-service date; normalized to a 40-year service life.

[b] Costs based on representative gate position indicator upgrade.

Table 8–50
Thermal Plant Upgrades: Performance

Plant and Measure	Incremental Capacity (MW)	Incremental Energy (MWa)	Incremental Heat Rate (Btu/kWh)	Earliest Service (year)	Operating Life (years)
Jim Bridger Upgrade[a]	33.0[b]	27.4[b]	0	1991	32
Beaver Upgrade 1[d]	37.0	25.9	6,189	1993	20
Beaver Upgrade 2[c,d]	75.0	52.5	6,773	1993	20
WNP-2 L.P. Rotor[e]	13.7	8.9	10,225	1992	32
WNP-2 Governor Valves[e]	8.0	5.2	0	1993	31

[a] Information from Idaho Power Company Draft Resource Management Report Least-Cost Plan Workpapers (undated, released January 1991).

[b] Idaho Power Company share.

[c] Beaver upgrade 2 is inclusive of Beaver upgrade 1.

[d] Information from Portland General Electric Company. *The 1990 Integrated Resource Plan: A Least-Cost Approach*, October 1980.

[e] Information from Washington Public Power Supply System letter from J.P. Burn to J.R. Lewis, Bonneville Power Administration "WNP-2 Megawatt Improvement Programs," May 1990.

Table 8-51
Thermal Plant Upgrades: Cost

Plant and Measure	Capital Cost ($/kW)[a]	Fixed O&M ($/kW/yr.)[a]	Variable O&M (m/kWh)[a]	Fixed Fuel Cost ($/kW/yr.)	Variable Fuel Cost ($/MM Btu)	Levelized Real (cents/kWh)[a]	Energy Cost Nominal (cents/kWh)[a]
Jim Bridger Upgrade	182	0.00	0.00	—	—	0.02	0.04
Beaver Upgrade 1	713	9.99	0.31	0.00	3.16	4.1	8.1
Beaver Upgrade 2	436	9.99	0.31	0.00	3.16	3.8	7.5
WNP-2 L.P. Rotor	1,460	18.68	4.6	27.72	0.5	3.3	6.6
WNP-2 Governor Valves	300	0.00	0.0	—	—	0.3	0.6

[a] "Overnight" cost (exclusive of interest during construction); per incremental capacity and energy.

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 8-44. 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 voltage 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 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 electrical energy are estimated to comprise about 7.5 to 9 percent of loads. Applying this estimate to the forecast Pacific Northwest firm electric load of 18,100 average megawatts for operating year 1989-1990 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 1989/1990 (PNUCC, 1989). Losses as a percentage, 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 area.

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).

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 is estimated. Finally, the Council's conclusions are described regarding transmission and distribution loss savings potential.

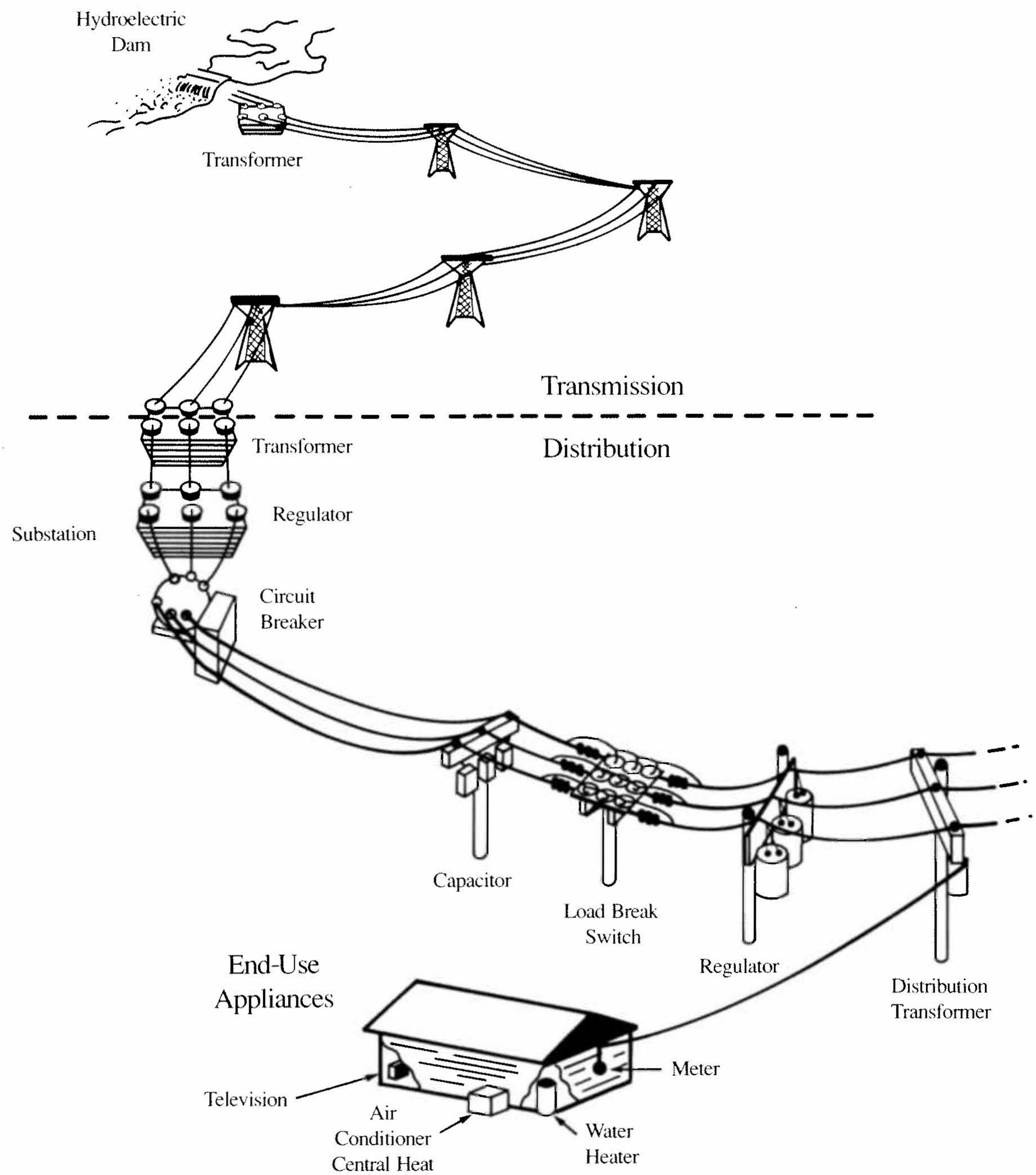
Table 8-52
Thermal Plant Upgrade Planning Characteristics (1990 Dollars)

	Thermal Plant Upgrades
Total Capacity (MW)	83
Total Firm Energy (MWa)	58
Unit Capacity (MW)	42
Seasonality	None
Dispatchability	Dispatchable
Siting and Licensing Lead Time (months)	12
Probability of Siting and Licensing Success (%)	95%
Siting and Licensing Shelf Life (years)	5
Probability of Hold Success (%)	90%
Construction Lead Time (months)	12
Construction Cash Flow (%/yr.)	10/90
Siting and Licensing Cost ($/kW)	$0
Siting and Licensing Hold Cost ($/kW/yr.)	$0
Construction Cost ($/kW)	$423
Fixed Fuel Cost ($/kW/yr.)	$0.00
Variable Fuel Cost (mills/kWh)	19.5[a]
Fixed OM&R Cost ($/kW/yr.)	$9.00
Variable O&M Cost (mills/kWh)	0.3
Earliest Service	1993
Peak Development Rate (units/yr.)	2
Service Life (years)	21
Real Escalation Rates (%/yr.)	
▪ Capital Costs	0%
▪ Fuel Costs	2.8%[a]
▪ O&M Costs	0%

[a] Hybrid natural gas price series used to simulate weighted thermal plant upgrade fuel costs.

Transmission and Distribution

Figure 8-44
Simplified Diagram of Transmission and Distribution (BPA 1987)



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 a 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, along with discussions with utility transmission and distribution staff, suggest that the loss reduction measures described below hold the greatest promise for application to transmission and distribution systems in the Pacific Northwest.

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. Increasing primary distribution feeder operating voltage requires complete feeder rebuilding 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. By locating these devices near the source of reactive load, reactive power transfer through the transmission and distribution system can be reduced. 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 has 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. Loads can often be shifted from heavily loaded feeders to more lightly loaded feeders by physical reconfiguration. In some cases the distance from the substation to the retail customer can be shortened by reconfiguration.

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 also 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 (PCBs).

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

Some 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. But, 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 may accelerate the removal of PCB and PCB-contaminated equipment (though many utilities have already removed PCB-containing 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 on the Bonneville system. This is followed by a discussion of potential savings on 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, additional loss-saving measures should be cost-effective.

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 used by the Council for preparation of this power plan. Loss reduction projects assessed in the 1987 updates to the Fiscal Year 1985-1986 Loss Savings Task Force report are listed in Table 8-53. The costs shown in Table 8-53 are the full costs of these projects. 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 (Table 8-54). Excluded from Table 8-54 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 (not shown in Table 8-53).

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 individual engineering study.

Regional Transmission and Distribution System Component Census

The CSEI study focused 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 8-55. The breakouts by investor-owned and consumer-owned utility systems are approximate.

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.

Table 8-53
Loss Reduction Measures—Bonneville Transmission System

Project	Measure	Peak Loss Savings (MW)	Average Loss Savings (MWa)	Capital Cost (MM $)	Annual O&M Cost (MM $/yr.)	Levelized Energy Cost Real (cents/kWh)	Levelized Energy Cost Nominal (cents/kWh)
Olympic Peninsula	Reinforcement	13.0	5.5	36.359	0.073	8.7	4.4
Kitsap Transformer	Tx Replacement[a]	2.0	0.8	4.110	0.000	6.2	3.1
Flathead Valley		6.0	2.5	21.578	0.043	11.2	5.7
Sno-King 230/500kV		5.0	2.1	22.922	0.046	14.3	7.3
Santiam-Conser		12.0	5.0	56.011	0.112	14.5	7.4
Trojan-St. Helens	Reconductoring	5.6	2.4	5.952	0.000	3.2	1.6
Southwest Portland	Reinforcement	2.3	1.0	3.636	0.007	4.9	2.5
Driscoll Support		2.3	1.0	7.588	0.015	10.3	5.2
Fry Loop-in	Reinforcement	4.4	1.8	11.856	0.024	8.4	4.3
Fairview	Reinforcement	5.0	2.1	19.542	0.039	12.2	6.2
Harvalum 500/230kV	Tx Replacement	3.5	1.5	10.275	0.000	8.8	4.5
Bellingham 230/115kV	Tx Replacement	0.5	0.2	2.924	0.000	17.6	8.9
Potlatch-Cushman No. 2 Powerhouse		5.0	2.1	0.776	0.002	0.5	0.2
Bellingham 500/230kV	Tx Replacement	9.1	3.8	10.749	0.000	3.5	1.8
Big Eddy-Chemawa Loop to Pearl	Reinforcement	0.8	0.3	1.028	0.002	4.0	2.0
Diablo-Bothell Loop to Murray	Reinforcement	1.6	0.7	2.400	0.005	4.7	2.4
Snohomish-Murray	Reconductoring	1.7	0.7	3.158	0.000	5.6	2.8
Custer-Bellingham	Reconductoring	1.6	0.7	2.398	0.000	4.5	2.3
Hungry Horse-Conkelly	Reconductoring	0.7	0.3	1.320	0.000	5.7	2.9
Salem-Grande Ronde	Reconductoring	2.9	1.2	2.637	0.000	2.7	1.4
Clatsop 230/115kV	Tx Replacement	0.4	0.2	1.541	0.000	11.6	5.9
Midway-Grandview	Reconductoring	2.3	1.0	4.758	0.000	6.2	3.2
S. Tillamook-Tillamook	Reconductoring	0.3	0.1	0.389	0.000	3.9	2.0
Brewster-Bridgeport	Reconductoring	0.6	0.3	1.138	0.000	5.7	2.9
Martin Creek-Doreena	Reconductoring	0.4	0.2	0.446	0.000	3.3	1.7
Box Canyon Tap	Reconductoring	0.2	0.1	0.427	0.000	6.4	3.3
All-Film Capacitors (Generic)	All-Film Capacitors	0.0	0.0	0.001	0.000	0.1	0.1
Columbia Falls		0.2	0.1	0.071	0.000	1.1	0.6
Reedsport T-962	Transformer Disconnect	0.0	0.0	0.000	0.000	0.0	0.0
Ponderosa 500/230kV		0.1	0.0	0.000	0.000	0.0	0.0

Table 8–53 (cont.)
Loss Reduction Measures: Bonneville Transmission System

Project	Measure	Peak Loss Savings (MW)	Average Loss Savings (MWa)	Capital Cost (MM $)	Annual O&M Cost (MM $/yr.)	Levelized Energy Cost Real (cents/kWh)	Nominal (cents/kWh)
Ledbedder T–757	Transformer Disconnect	0.0	0.0	0.000	0.000	0.0	0.0
Monmouth T–756	Transformer Disconnect	0.0	0.0	0.000	0.000	0.0	0.0
Valley Way T–902	Transformer Disconnect	0.0	0.0	0.000	0.000	0.0	0.0
DC Parallel Line—Oregon	Reinforcement	66.5	25.9	88.053	0.176	4.4	2.3
Martin Creek—Cottage Grove	Reconductoring	0.4	0.1	0.453	0.000	5.7	2.9
Ringold—Connell Tap 115kV	Reconductoring	0.2	0.1	1.059	0.000	13.4	6.8
Santiam–Bethel 230kV Reconductor	Reconductoring	1.6	0.5	1.479	0.000	3.8	1.9
Shelton 500/230kV Addition	Reinforcement	13.2	4.4	38.241	0.076	11.5	5.8
Olympia 230/115kV Transformer	Tx Replacement	1.5	0.4	2.225	0.000	6.9	3.5
Roundup 230/69kV Transformer	Tx Replacement	0.4	0.2	1.556	0.000	9.8	5.0
Rocky Reach 345/230kV Transformer	Tx Replacement	0.4	0.1	5.134	0.000	64.8	32.9

[a] Tx—Transformer.

Table 8-54
Supply Curve of Loss Savings on the Bonneville Transmission System (1990 Dollars)

Levelized Energy Cost (nominal cents/kWh)	Cumulative Loss Savings (MWa)
1	2.2
2	2.3
3	3.5
4	10.3
5	12.1
6	14.4
7	16.3
8	16.7
9	25.5
10	25.5
11	26.7
12	33.6
13	35.8
14	35.9
15	43.1

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 8-56. The costs of Table 8-56 have been escalated to 1990 dollars using the Handy Whitman Index of public utility costs.

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. Therefore, the costs in Table 8-56 include no allowance for installation, nor do they include engineering or administrative costs, nor contingency allowances. The installation costs for high-efficiency equipment should be no greater than for equipment of standard efficiency. 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 and escalated to 1990 dollars, are shown in Table 8-57.

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 8-58 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 8-56 and 8-57, 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 1990 dollars.

Table 8–55
Estimated Pacific Northwest Population of Transmission and Distribution System Components

Component	Average Capacity	Population IOU Systems (units)	Population COU 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—Amperes.

[b] Megavolt—Amperes.

[c] American Wire Gauge (conductor size).

[d] Thousand circular mills (cable size).

Table 8–56
Cost and Performance of Silicon Steel Core Distribution Transformers

		Existing Stock				High-Efficiency Units			
Nominal Rating Category (kVA)[a]	Average Capacity (kVA)	Efficiency (%)	No-Load Loss (watts)	Load Loss (watts)	Unit Cost ($/unit)	Efficiency (%)	No-Load Loss (watts)	Load Loss (watts)	Unit Cost ($/unit)
7	5	97.0%	43	109	$304	97.6%	30	91	$317
15	10	97.5%	67	188	$370	98.0%	47	148	$393
25	15	97.5%	90	280	$430	98.3%	64	198	$462
40	28	97.4%	182	547	$575	98.3%	119	363	$612
50	48	97.9%	247	746	$819	98.7%	154	470	$889
75	52	98.0%	247	774	$870	98.8%	158	486	$947
100	75	98.4%	286	900	$1,160	99.0%	182	558	$1,281
200	118	98.8%	334	1,062	$1,712	99.4%	213	547	$2,003
300	232	99.3%	406	1,300	$3,237	99.6%	257	781	$3,839
500	305	99.4%	435	1,394	$4,254	99.6%	275	836	$5,164
500 +	1,032	99.8%	565	1,821	$15,720	99.9%	354	1,077	$22,092

[a] Kilovolt—Amperes.

Table 8–57
Example Cost and Performance Amorphous Metal Core Distribution Transformers (1990 Dollars)

Nameplate Rating (kVA)[a]	Efficiency (%)	No-Load Loss (watts)	Load Loss (watts)	Equipment Cost ($/unit)
25	99.0	28	213	$930
25	98.9	19	253	$982
50	99.1	36	413	$1,380
50	99.0	31	481	$1,305
75	99.2	50	526	$2,064
100	N/A	N/A	N/A	$2,374

[a] Kilovolt—Amperes.

Table 8–58
Cost and Performance of Transmission and Distribution System ACSR[a] Conductors (1990 Dollars)

Size (AWG)[b]	Size (Mcmil)[c]	Resistance (Ohm/mile)	Cost (New Construction) ($/mile)	Cost (Reconductoring) ($/mile)
—	1,033.5	0.104	$79,100	$70,700
—	874.5	0.123	$72,200	$63,700
—	500.0	0.206	$55,800	$47,300
—	336.4	0.306	$48,600	$40,200
—	266.8	0.385	$45,600	$37,100
3/0	167.8	0.720	$41,200	$32,800
2/0	133.1	0.890	$39,700	$31,300
1	83.7	1.380	$37,600	$29,100
4	41.7	2.570	$35,700	$27,300

[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 insulators. 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 $2,166 per mile (1990 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 8-56. 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 trim-line 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 in this assessment.

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 8-59. Nominal costs were normalized to a 40-year service life, consistent with the convention used for other resources.

Table 8-59
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 1990
▪ Service Life	30 years[a]

[a] The nominal levelized energy costs appearing in the following tables are normalized to a 40-year service period, consistent with other resource costs.

These assumptions yield the levelized energy costs shown in Table 8-60. Levelized energy costs are in nominal dollars for a reference in-service year of 1990.

Technical 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, many primary distribution feeders 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:

Table 8-60
Levelized Energy Cost of Transmission and Distribution System Loss Reduction Measures
(Nominal Dollars, 1990 In-Service)

Measure	IOU Systems (cents/kWh)	COU Systems (cents/kWh)
Upgrade Distribution Transformers		
▪ 0-7.5 kVA[a] Units (5 kVA average)	2.1	1.4
▪ 7.6 to 15.0 kVA Units (10 kVA average)	2.2	1.5
▪ 15.1 to 25.0 kVA Units (15 kVA average)	2.1	1.5
▪ 25.1 to 40.0 kVA Units (28 kVA average)	1.2	0.8
▪ 40.1 to 50.0 kVA Units (48 kVA average)	1.3	0.9
▪ 50.1 to 75.0 kVA Units (52 kVA average)	1.6	1.1
▪ 75.1 to 100.0 kVA Units (75 kVA average)	2.4	1.7
▪ 100.1 to 200.0 kVA Units (118 kVA average)	4.6	3.3
▪ 200.1 to 300.0 kVA Units (232 kVA average)	8.4	5.8
▪ 300.1 to 500 kVA Units (305 kVA average)	11.8	8.1
▪ 500+ kVA Units (1,032 kVA average)	59	41
Reconductor Primary Distribution Feeders		
▪ 0 to 11.9 kV Feeders (4 AWG[b] to 1 AWG)	5.6	3.9
▪ 12.0 to 17.0 kV Feeders (2/0 AWG to 266.8 Mcmil)[c]	6.3	4.3
▪ 18.0 to 50.0 kV Feeders (1 AWG to 3/0 AWG)	9.8	6.7
Reconductor Transmission Lines		
▪ 34.5 kV Circuits (2/0 AWG to 266.8 Mcmil)	70.2	48.1
▪ 69 kV Circuits (2/0 AWG to 266.8 Mcmil)	18.2	12.5
▪ 115 kV Circuits (336.4 Mcmil to 500.0 Mcmil)	8.8	6.0
▪ 230 kV Circuits (874.5 Mcmil to 1,033.5 Mcmil)	8.9	6.1

[a] Kilovolt—Amperes.

[b] American Wire Gauge (conductor size).

[c] Thousand circular mills (cable size).

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

Applying these technical application fractions to the component inventory of Table 8-55 yields the estimates of transmission and distribution system loss reduction technical potential of Table 8-61. 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 8-61
Technical Potential[a] 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

[a] At 15 cents per kilowatt-hour, or less.

Achievable Potential: Transmission and Distribution Loss Reduction

Several factors may discourage full implementation of the technically available transmission and distribution loss reduction potential. Among these are the following.

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 higher-profile 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.

- ***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 incentives for recovery of the cost of measures that are regionally cost-effective can be provided to all utilities. Furthermore, we assume that programs can be established to allow small utilities to secure the engineering expertise needed 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 silicon steel 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 rebuilding 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 about 3 percent per year. Additional information on the age distribution of existing equipment 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, other 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 power 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 procedures 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 availability of electricity savings is 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 meter. However, conservation voltage regulation implemented to this degree would probably not be cost-effective, because the capital costs of voltage regulating devices required to achieve an equal voltage at each meter would be much higher than current voltage control practice. Typically, utilities implementing conservation voltage regulation 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.

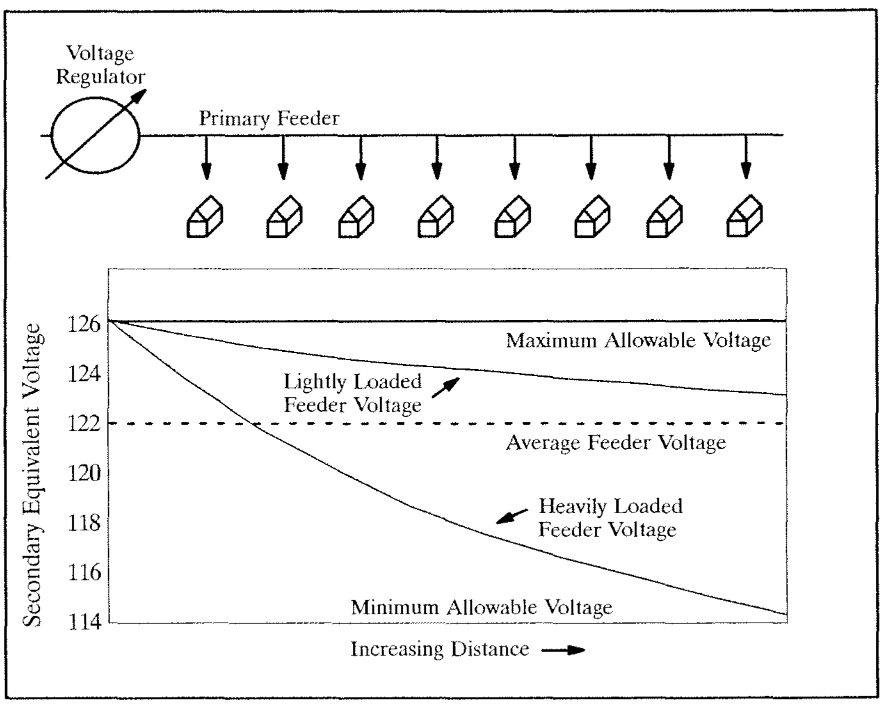
Typically, conservation voltage regulation measures are designed to lower the average delivered voltage from about 120 volts to about 117.5 volts. The voltage drop along a distribution feeder is determined by the impedance[49] of the line, the loading of the line, and the distance from the substation. A simplified depiction of voltage drop is shown in Figure 8–45 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 about 123 volts at the end of the feeder when the feeder is lightly loaded. The voltage at the end of the feeder drops to about 114 volts when the feeder is heavily loaded during periods of peak demand. As can be seen in Figure 8–45, 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 8–45 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 reduced to 117 volts 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 under all load conditions, is the technique used by most utilities to implement conservation voltage regulation. This situation is depicted in Figure 8–46. 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. Continuing with the example of Figure 8–45, the line drop compensator reduces substation voltage automatically to 117 volts at light-load times and voltage is maintained at 114 volts at the end of the feeder, as under high-load conditions.

49. 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).

Voltage Profile— no CVR

Figure 8–45
Voltage Profile with no Conservation Voltage Regulation



Voltage Profile— no CVR

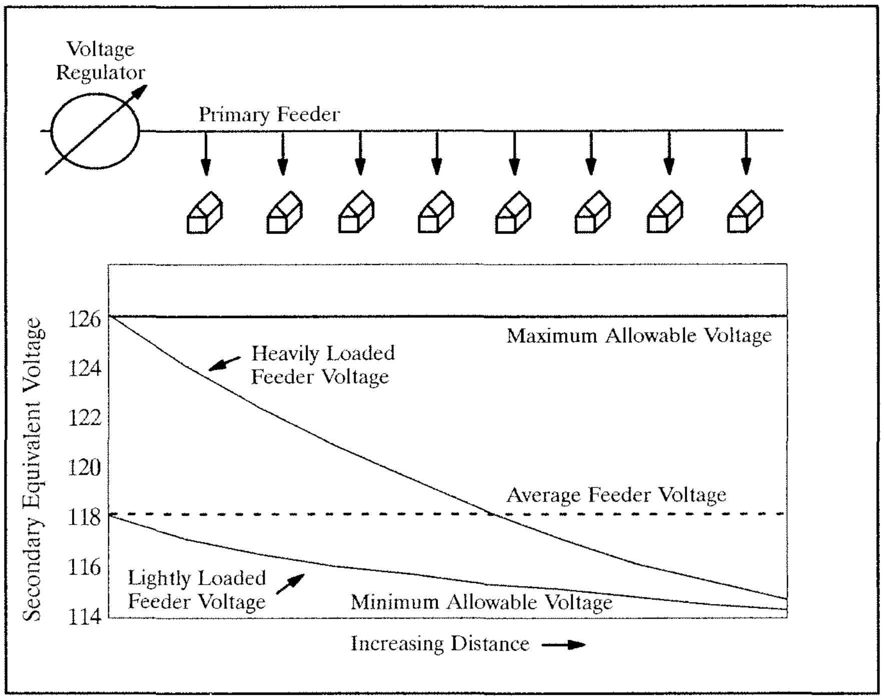


Figure 8–46
Voltage Profile with Conservation Voltage Regulation

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.

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 confirmed 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, Snohomish County Public Utility District 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.[50]

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.[51] As will be shown below, savings can differ significantly depending on

50. Based on telephone communication with Bob Fletcher of Snohomish County Public Utility District.

51. Based on telephone communication with Bob Fletcher of Snohomish County Public Utility District.

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, such as 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.

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 experience lower 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 reduction in lighting levels is minor, some have considered these savings as conservation. But "savings" of these kinds are not considered as conservation, as it is defined by the Act and applied by the Council. 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 an indication that most areas are 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 used is not changed.

Some analysts have reported capacity (peak) 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 most customers take showers, baths, and raise thermostats within a couple of hours in the morning, conservation voltage regulation might lower and broaden the morning peak. Further 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[52] 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, for example, 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.[53] Therefore, conservation voltage regulation on circuits feeding industrial loads might not be wise. However, the feasibility of 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 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 measures 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 8-62 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 have included costs to reconductor the distribution feeder. Without the PG&E data point, the average is well below $50,000 per feeder.

As was indicated earlier, the costs in Table 8-62 are the total dollar cost divided by the cumulative savings of energy. As such, average 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.

52. The information contained in this paragraph came from personal communication with a large AC motors expert from Toshiba International.

53. 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.

Table 8-62
Costs of Energy Savings from Conservation Voltage Regulation in California Years 1977-1985

Utility	Cost (cents/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

In 1985, the last year for which staff has data, California utilities are estimated to have saved 2.83 billion kilowatt-hours, or about 2 percent of their total load through conservation voltage regulation. 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 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. 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 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[54]

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, 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 earlier 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 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

54. 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 number 89-40 *Wind Resources*, 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.

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 at 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

Most wind resource areas are remote from load centers. The development of such areas will require new transmission lines from the wind power stations to the existing electrical grid, and in some cases, reinforcement of the grid to load centers. 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 an 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[55] that may have to be controlled by installation of shunt capacitors or other reactive compensation at or near the wind power station switchyard. The variable speed 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).

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 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 adaptation of contemporary turbine designs to this environment is needed before large-scale development of the wind resources of these areas can commence.

Seasonality and Intermittence of Wind Power

Wind energy production varies hourly, seasonally and, to a lesser extent, annually. The storm-driven winds of the Pacific Northwest are 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.

55. Reactive power is the power that is used to magnetize 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.

These problems tend to be less significant when wind represents a small portion of the total generating capacity of the system, but may surface as the contribution of wind-powered energy increases. However, the increasing diversity of larger and more widespread wind power developments may compensate for 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 the Bonneville study listed under "references" at the end of this chapter.

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 designed and sited. 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. Therefore, 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.

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 8-63.

Visual conflicts can be controlled by turbine layouts, tower heights, and transmission line routings 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.

Table 8–63
Wind Resource Area Development Issues

State/Area	Access Problems	Trees	Icing & Snow	County Regulation[a]	More Wind Data Needed	Visual Impacts	Environmental Impacts	Gorge Constraints[b]
Idaho								
▪ Albion Butte	Y[c]	N[d]	Y	N	Y		Y	N
▪ Bennett Peak	Y	N	Y	N	Y	potential[e]	Y	N
▪ Duncan Mtn.	Y	N	Y	N	Y		unknown	N
▪ Strevell	N	N	Y	N	Y	potential	unknown	N
Montana								
▪ Blackfoot Area	N	N	N	N	Y		unknown	N
▪ Great Falls	N	N	N	N	Y		unknown	N
▪ Livingston	N	N	N	N	Y		unknown	N
▪ Sieban 1	Y	N	Y	N	Y		unknown	N
▪ Sieban 2	N	N	N	N	Y		unknown	N
Nevada								
▪ Pequop Summit	Y	N	Y	N	Y		unknown	N
▪ Wells W.	N	N	N	N	N		unknown	N
Oregon								
▪ Adel	N	N	N	N	Y		unknown	N
▪ Burns Butte	N	N	N	N			unknown	N
▪ Cape Blanco	N	N	N	N	N	potential	Y	N
▪ Cascade Locks	N	Y	Y	N	N	potential	unknown	Y
▪ Coyote Hills	N	N	N	N	Y		unknown	N
▪ Florence Jetty	N	N	N	N	Y	potential	Y	N
▪ Gold Beach Area	N	Y	N	N	N		unknown	N
▪ Hampton Butte	N	N	N	N	Y		unknown	N
▪ Klondike	N	N	Y	N	Y	potential	unknown	N
▪ Langlois	N	N	N	N	Y	potential	Y	N
▪ Langlois Mtn.	N	Y	N	N	Y		unknown	N
▪ Prairie Mtn.	N	Y	N	N	Y		unknown	N
▪ Pueblo/Steens	Y	N	N	N	Y		unknown	N
▪ Pyle Canyon	N	N	N	N	Y		unknown	N
▪ Sevenmile Hill	N	unk	N	Y	N	potential	unknown	Y
▪ Winter Ridge	Y	N	N	N	Y		unknown	N
Washington								
▪ Beezley Hills	N	N	N	N	Y		unknown	N
▪ Boylston Mtn.	N	N	N	N	Y		unknown	N

Table 8-63 (cont.)
Wind Resource Area Development Issues

State/Area	Access Problems	Trees	Icing & Snow	County Regulation[a]	More Wind Data Needed	Visual Impacts	Environmental Impacts	Gorge Constraints[b]
Washington (cont.)								
▪ Burdoin Mtn.	N	N	N	N	Y	potential	unknown	Y
▪ Cape Flattery	N	Y	N	N	Y		unknown	N
▪ Columbia Hills E	Y	N	N	N	N		unknown	N
▪ Columbia Hills W	Y	N	N	N	Y	potential	unknown	Y
▪ Goodnoe Hills	N	N	Y	N	N		unknown	N
▪ Horse Heaven	N	N	N	N	Y		unknown	N
▪ Kittitas Valley E	N	N	N	N	N		unknown	N
▪ Murdock Area	N	N	N	N	Y	potential	unknown	Y
▪ Rattlesnake Mtn.	N	N	N	N	Y		unknown	N
▪ Roosevelt	Y	N	N	N	Y		unknown	N
▪ Tule Hills	N	N	N	N	Y		unknown	N

[a] Other regulations may apply. Oregon sites would be covered by statewide wind energy siting standards if the project by the same developer were 25 megawatts or greater in size. Montana's statewide environmental standards generally would apply to all Montana sites. If a Bonneville Power Administration transmission line extension were required, a federal EIS generally would apply.

[b] Columbia River Gorge scenic restrictions.

[c] Y—Yes.

[d] N—No.

[e] Potential—the issue has been raised.

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

Bonneville hired Oregon State University 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 8-47).

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 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 8-64.

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[56] wind speed distributions are used instead, except for 12 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. Because the range of elevations varies for the Northwest's wind resource areas, 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 8-64 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 11 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 11 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 less than $1,000 per kilowatt,[57] 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 highway 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.

56. The distribution of wind speeds at a site may be estimated, based on mean wind speed data only, by using a probability density function called the Rayleigh distribution. The Rayleigh distribution is defined as:

$$F_v(V_{ave}) = \frac{\Pi}{2}\left(\frac{V^2}{V_{ave}}\right)^{-\left[\frac{\Pi}{4}\left(\frac{V}{V_{ave}}\right)^2\right]}$$

Where:

$F_v(V_{ave})$ = Rayleigh frequency distribution as a function of V_{ave}

V_{ave} = Mean wind speed; and

V = Median value of the wind speed increment

57. The costs described in this and the following six paragraphs are in 1988 year dollars, the year dollars appearing in the Council's wind issue paper.

Wind Resource Areas

Figure 8-47
Wind Resource Areas
in the Pacific Northwest

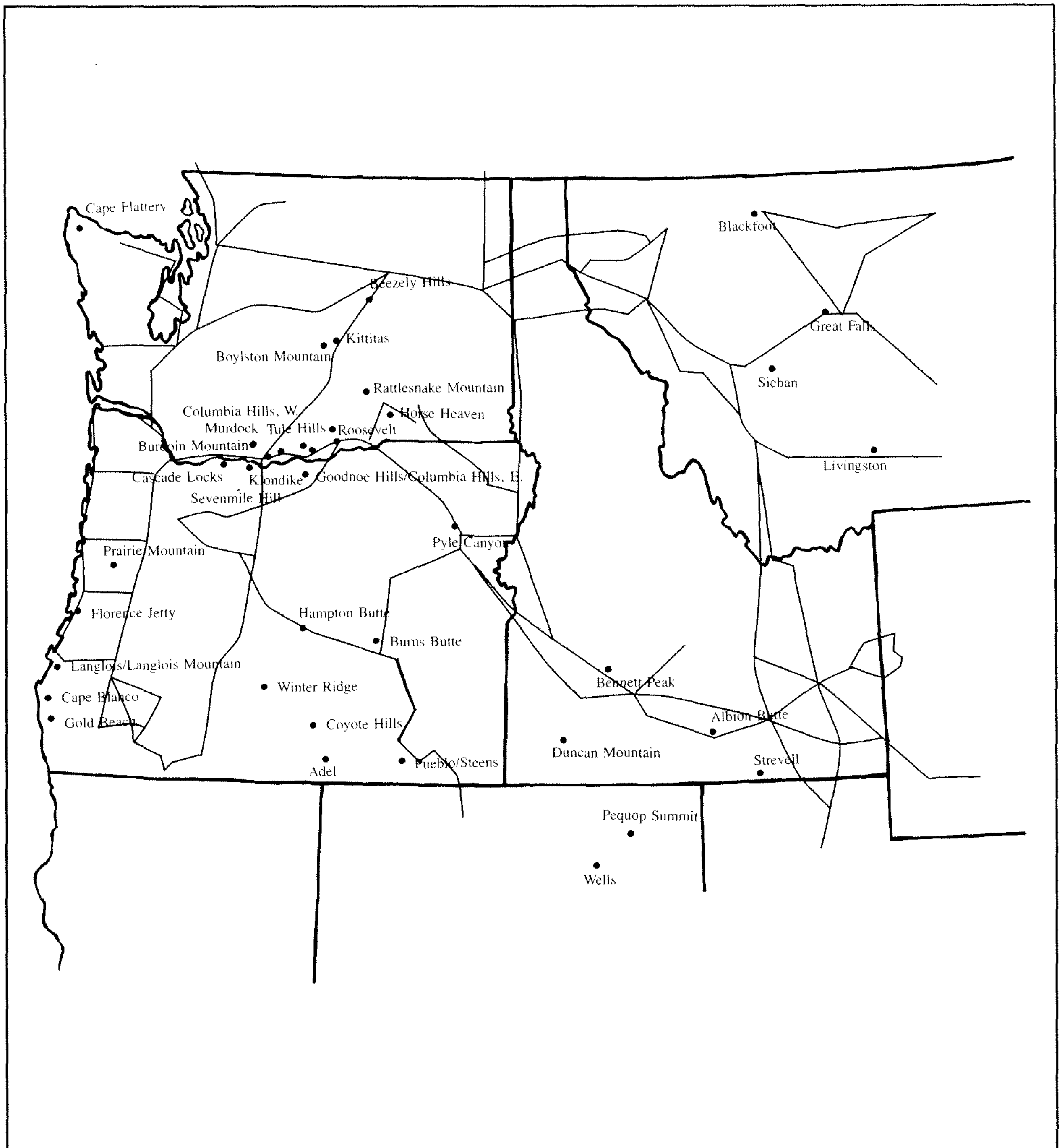

Table 8-64
Wind Resource Area Wind Measurements

State/Area	Terrain Type[a]	Elevation MSL[b]	Speed (mph)[c]	Shear[d]	Data Confidence[e]	Data Type[f]	Peak Season[g]
Idaho							
▪ Albion Butte	RC	7,110	17	.10	B	MO	Fall
▪ Bennett Peak	RD	7,440	16	.14	L	HR	Winter
▪ Duncan Mtn.	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 Mtn.	RC	1,120	14	.07	B	HR	Winter
▪ Prairie Mtn.	RC	3,200	14.3	.07	B	HR	Fall–Winter
▪ 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

Table 8-64 (cont.)
Wind Resource Area Wind Measurements

State/Area	Terrain Type[a]	Elevation MSL[b]	Speed (mph)[c]	Shear[d]	Data Confidence[e]	Data Type[f]	Peak Season[g]
Oregon (cont.)							
▪ Winter Ridge	RC	7,060	14.9	.20	B	HR	Winter
Washington							
▪ Beezley Hills	RD	2,600	13	.07	E	HR	Spring–Summer
▪ Boylston Mtn.	RD	2,400	12	.07	B	HR	Spring–Summer
▪ Burdoin Mtn.	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] Terrain 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] Data Type: HR—Hourly, MO—Monthly.

[g] The season(s) when potential electric generation peaks.

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 could 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 8-65) 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.

Costs, adjusted to 1990 dollars, and performance assumptions for the base case representative wind power project are shown in Table 8-66.

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 8-67. 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 the introduction to this chapter. Land rent (wind rights) royalties add another five percent to the cost of energy. The resulting levelized energy costs range from 9.6 cents per kilowatt-hour for the Columbia Hills East area to 21.0 cents per kilowatt-hour for the Duncan Mountain area (see Table 8-67).

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 8-67) 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 8-67) 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 (Table 8-64). Linear arrays of one to three rows of turbines were assumed for ridgelines and deeper arrays for plains (Table 8-67). 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 8-67. 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 8-65
Estimated Interim Capital Replacement Costs[a] for a 200 to 300-Kilowatt Machine

Year	1989 Dollars (thousands)	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

Table 8-65 (cont.)
Estimated Interim Capital Replacement Costs[a] for a 200 to 300-Kilowatt Machine (Assume 250 Kilowatt)

Year	1989 Dollars (thousands)	Item
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.

Table 8-66
Cost and Performance Characteristics of a Representative Wind Power Station (1990 Dollars)

	Representative Wind Power Station[a]
Plant Configuration	150 to 200-kilowatt units
Machine Type	Horizontal Axis, 82-foot diameter blades
Rated Capacity (MW/unit)	0.25
Peak Capacity (MW/unit)	N/A
Equivalent Annual Availability (%)	95%
Siting and Licensing Cost ($/kW)	$16
Siting and Licensing Hold Cost ($/kW/yr.)	$4.00
Construction Cost ($/kW)[b]	$1,086
Fixed O&M Cost ($/kW/yr.)[c]	$0.15
Variable O&M Cost (mills/kWh)	12.0
Post-op Capital Replacement Cost	$16.10
Wind Rights Royalty	5% of total energy costs
Siting and Licensing Lead Time (months)	24
Construction Lead Time (months)	24[d]
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). Excludes access road and transmission interconnection costs. These are site-specific.

[c] Decommissioning fund contribution.

[d] From equipment order. Equipment order could proceed following one year of siting and licensing activity.

Table 8-67
Regional Wind Potential and Site Cost-Effectiveness (1990 Dollars)

State/Area	Spatial Extent[a]	Usable Portion (%)	Array Layout[b]	Number of WTG[c]	Installed Capacity (MW)	Capacity Factor[d] (%)	Technical Potential[f] (MW)	Technical Potential[f] (MWa/yr.)	Energy Cost[e] (cents/kWh)
Idaho									
▪ Albion Butte	13	50	2R-10X	84	16.8	25.4	16.5	4.1	12.7
▪ Bennett Peak	8	40	1R-10X	21	4.2	25.9	4.1	1.1	12.6
▪ Duncan Mtn.	90	60	8X10	2,970	594.0	14.3	582	83	21.0
▪ Strevell	8	60	8X10	251	50.2	17.7	49	8.6	17.1
Montana									
▪ Blackfoot Area 1	1,500	50	10X10	35,588	7,117.6	30.4	7,030	2,100	11.8
▪ Blackfoot Area 2	750	50	10X10	17,763	3,552.6	25.2	3,480	870	13.7
▪ Blackfoot Area 3	1,000	50	10X10	23,853	4,770.6	19.2	4,680	890	17.1
▪ Great Falls	75	60	8X10	2,484	496.8	24.5	490	120	13.1
▪ Livingston	25	80	8X10	1,092	218.4	24.9	210	53	13.0
▪ Sieban 1	15	40	5X10	490	98.0	24.6	96	23	13.1
▪ Sieban 2	35	40	5X10	1,170	234.0	18.5	230	42	16.4
Nevada									
▪ Pequop Summit	8	40	1R-5X	41	8.2	21.1	8.0	1.7	14.8
▪ Wells W.	4	40	8X10	84	16.8	14.8	17	2.4	19.9
Oregon									
▪ Adel	14	80	3R-10X	216	43.2	22.3	42	9.4	14.1
▪ Burns Butte	8	50	1R-10X	26	5.2	16.7	5.1	0.8	18.0
▪ Cape Blanco	2.5	50	8X10	66	13.2	23.2	13.0	3.0	13.9
▪ Cascade Locks	1.2	10	1R-10X	1	.2	30.4	0.2	0.1	10.7
▪ Coyote Hills	5	50	8X10	128	25.6	24.5	25	6.1	13.3
▪ Florence Jetty	2	60	2R-10X	16	3.2	19.1	3.1	0.6	16.0
▪ Gold Beach Area	3	50	1R-10X	10	2.0	18.0	2.0	0.4	16.8
▪ Hampton Butte	4	50	1R-10X	13	2.6	23.5	2.5	0.6	13.6
▪ Klondike 1	15	40	8X10	324	64.8	25.1	64	16	12.2
▪ Klondike 2	200	40	8X10	4,475	895.0	18.0	880	160	16.0
▪ Langlois	4	70	8X10	147	29.4	17.6	29	5.0	17.2
▪ Langlois Mtn.	3.5	60	1R-5X	27	5.4	23.1	5.3	1.2	13.7
▪ Prairie Mtn.	4	30	1R-10X	8	1.6	22.3	1.6	.3	13.6
▪ Pueblo/Steens	18	40	1R-5X	93	18.6	29.0	18	5.2	11.5
▪ Pyle Canyon	12	40	8X10	259	51.8	15.1		7.6	18.6
▪ Sevenmile Hill	3	60	5X10	139	27.8	28.4	27	7.7	11.1

Table 8–67 (cont.)
Regional Wind Potential and Site Cost–Effectiveness (1990 Dollars)

State/Area	Spatial Extent[a]	Usable Portion (%)	Array Layout[b]	Number of WTG[c]	Installed Capacity (MW)	Capacity Factor[c] (%)	Technical Potential[f] (MW)	Technical Potential[f] (MWa/yr.)	Energy Cost[e] (cents/kWh)
Oregon (cont.)									
▪ Upper Pyle Canyon	6	50	8X10	162	32.4	20.9	32	6.6	14.2
▪ Winter Ridge	27	70	3R–8X	456	91.2	24.9	89	22	13.0
Washington									
▪ Beezley Hills	17	60	3R–10X	197	39.4	18.4	39	7.1	15.8
▪ Boylston Mtn.	8	60	1R–8X	38	7.6	15.2	7.4	1.1	18.7
▪ Burdoin Mtn.	3	50	5X10	116	23.2	15.4	23	3.5	18.3
▪ Cape Flattery	13	40	2R–5X	134	26.8	32.9	26	8.6	10.4
▪ Columbia Hills E. 1	4	60	2R–10X	31	6.2	34.8	6	2.1	9.5
▪ Columbia Hills E. 2	7	60	2R–10X	54	10.8	26.9	11	2.8	11.6
▪ Columbia Hills W.	20	60	1R–10X	77	15.4	23.0	15	3.4	13.2
▪ Goodnoe Hills	1.5	60	5X10	72	14.4	27.1	14	3.8	11.6
▪ Horse Heaven	34	40	2R–5X	350	70.0	24.2	69	17	12.6
▪ Kittitas Valley E.	12	60	8X10	389	77.8	17.3	76	13	16.6
▪ Murdock Area	5	50	5X10	196	39.2	22.3	38	8.5	13.4
▪ Rattlesnake Mtn. 1	16	50	2R–8X	129	25.8	33.7	25	8.4	9.8
▪ Rattlesnake Mtn. 2	7	50	2R–10X	45	9.0	18.2	9	1.6	16.0
▪ Roosevelt	2	50	5X10	77	15.4	21.8	15	3.3	13.7
▪ Tule Hills	6	60	10X10	162	32.4	18.0	32	5.7	16.4

[a] Miles: Square miles gross site area or linear 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 8–64 "Terrain 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 1990 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 8–67 appears to be developable at this time.

The three Blackfoot wind resource areas encompass much of the Blackfeet Indian Reservation[58] in north central Montana. Because of the large size of the Blackfoot 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 Blackfoot 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 had not been prepared at the time this plan was developed, but the resulting transmission distance would likely render the Blackfoot resource more costly to develop.[59]

A portion of the Blackfoot 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 Blackfoot 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 Blackfoot area to Great Falls. A rough estimate of the cost of this transmission is included in the energy cost estimates of Table 8-67.

For this reason, we have limited the estimated potential from the Blackfoot 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 8-63). 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 about 660 megawatts of wind-generated energy could be obtained by the development of about 2,900 megawatts of wind project capacity. The cost of this energy is estimated to range from 9.6 to 16.8 cents per kilowatt-hour, excluding credits or penalties resulting from factors such as seasonality, wind variability or lead time. The supply curve for this energy is shown in Table 8-68.

About 350 megawatts of this energy is available from the Livingston, Great Falls, Sieban and Blackfoot areas in Montana. Approximately 190 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 three resource blocks on the basis of energy cost. The first resource block is small: 29 megawatts of energy. This block is competitive in cost with new coal projects. The second and third blocks of 381 and 253 megawatts are resources that could be developed at progressively higher costs.

Resolution of questions regarding system integration might indicate that a much larger portion of the Montana resource could be developed. A fourth 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 four blocks of wind resources are shown in Table 8-69.

58. The wind resource area largely located on the Blackfeet Indian reservation is designated as the "Blackfoot" wind resource area in the regional wind energy assessment report (Baker, et. al., 1985).

59. The Pacific Northwest Utilities Conference Committee has subsequently prepared an assessment of transmission interconnection for the wind resources of the Blackfeet Indian Reservation. This assessment is scheduled for publication in September 1991.

Table 8-68
Pacific Northwest Wind Resource Potential Available for Development (1990 Dollars)

Wind Resource Area	Capacity (MW)	Energy (MWa)	Levelized Energy Cost[a] (cents/kWh)
Columbia Hills East 1	6	2	9.5
Rattlesnake Mountain 1	26	9	9.8
Cape Flattery	13	4	10.4
Sevenmile Hill	7	2	11.1
Pueblo/Steens	19	5	11.5
Goodnoe Hills	14	4	11.6
Columbia Hills East 2	11	3	11.6
Blackfoot Area 1	450	137	11.8
Klondike 1	65	16	12.2
Horse Heaven	70	17	12.6
Livingston	218	54	13.0
Winter Ridge	91	23	13.0
Great Falls	497	122	13.1
Columbia Hills West	3	1	13.2
Coyote Hills	5	1	13.3
Hampton Butte	3	1	13.6
Prairie Mountain	2	1	13.6
Langlois Mountain	5	1	13.7
Roosevelt	15	3	13.7
Cape Blanco	13	3	13.9
Adel	43	10	14.1
Upper Pyle Canyon	32	7	14.2
Beezely Hills	39	7	15.8
Florence Jetty	2	< 1	16.0
Rattlesnake Mountain 2	9	2	16.0
Klondike 2	895	161	16.0
Sieban 2	234	43	16.4
Tule Hills	32	6	16.4
Kittitas Valley East	78	14	16.6
Gold Beach Area	2	< 1	16.8
Total	2,900	659	9.5 – 16.8

[a] Nominal dollars.

Table 8-69
Wind Power Planning Assumptions

	Wind 1	Wind 2	Wind 3	Wind 4
Total Capacity (MW)	96	1,445	1,380	3,293
Total Average Energy (MWa)	29	381	253	1,000
Total Firm Energy (MWa)	29	381	253	1,000
Unit Capacity (typical project) (MW)	19	31	30	30
Seasonality	Summer Peaking	Winter Peaking	Winter Peaking	Winter Peaking
Dispatchability	Must-run	Must-run	Must-run	Must-run
Siting and Licensing Lead Time (months)[a]	12	12	12	12
Probability of Siting and Licensing Success (%)	90	90	90	90
Siting and Licensing Shelf Life (years)	5	5	5	5
Probability of Hold Success (%)	90	90	90	90
Construction Lead Time (months)[b]	24	24	24	24
Construction Cash Flow (%/yr.)	40/60	40/60	40/60	40/60
Siting and Licensing Cost ($/kW)	$16	$17	$16	$17
Siting and Licensing Hold Cost ($/kW/yr.)	$4	$4	$4	$4
Construction Cost ($/kW)	$1,125	$1,191	$1,111	$1,277
Fixed OMR&D Cost ($/kW/yr.)[c]	$16	$17	$16	$17
Variable O&M Cost (mills/kWh)	12.1	12.4	12.0	12.5
Earliest Service	1995	1997	2001	1997
Peak Development Rate (projects/yr.)	2	16	16	16
Operating Life (years)	40	40	40	40
Real Escalation Rates (%/yr.)				
▪ Capital Costs	0	0	0	0
▪ O&M Costs	0	0	0	0

[a] To turbine order. Overall siting and licensing is estimated to require two years.

[b] From turbine order.

[c] Includes operation, maintenance, 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 electrical energy at costs generally competitive with electrical 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 about 660 megawatts of energy could be obtained from wind resources currently capable of development. The estimated cost of energy from these sites ranges from 9.5 to 16.8 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 2,900 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.

The following actions, further described in Volume II, Chapter 1, 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 a regional wind farm demonstration project.

References

Baker, R. W., et. al. 1985, *Pacific Northwest Wind Regional Energy Assessment Program*, BPA 85-19, Vol. I and II. Prepared by Oregon State University for the Bonneville Power Administration, Portland, Oregon.

Bonneville Power Administration, 1989. *Integration of Wind Energy into the Electrical Utility System: An Overview of the Issues*. Prepared by the Energy Resources Research Laboratory for the Bonneville Power Administration, Portland, Oregon.

Lynette, R., K. Conner and J. Young. *Experiences With Commercial Wind Turbine Design*, GS-6245, Vols I & II. Electric Power Research Institute, Palo Alto, California, April 1989.

APPENDIX 8-A

REPRESENTATIVE THERMAL POWER PLANTS

This appendix provides detailed information concerning the derivation of the cost and performance assumptions for the representative thermal power plants of this plan. Minor discrepancies between the information appearing in this appendix and the plant characteristics appearing in Chapter 8 result from refinement and corrections of information regarding these power plants since completion of the analyses embodies in the power plan. These differences do not materially affect the conclusions of this plan.

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Northwest Power Planning Council Representative Power Plant
25 MW WOOD RESIDUE POWER PLANT
(Direct-fired Steam-electric)
January 1990 Base Year

GENERAL PLANT DESCRIPTION

Type:	Direct-fired steam-electric	
Configuration:	One 25MW unit	
Site:	Western Washington	
Primary Fuel:	Mixed wood residue	
Heat Value (Btu/lb, HHV)	4500	
Delivery	Truck	
Inventory (days)	60	
Fixed Cost ($/kW/yr)	$0.00	
Variable Cost ($/MMBtu)	$2.57	Note 1
Alternate Fuel:	None	
Heat Value (Btu/lb, HHV)	n/a	
Delivery	n/a	
Inventory (days)	None	
Fixed Cost ($/kW/yr)	n/a	
Variable Cost ($/MMBtu)	n/a	
Environmental Controls:		
Heat Rejection	Mechanical draft cooling towers	
Air Emission Controls: Particulates	Electrostatic precipitator	Ebasco(84)
Grid Interconnection:		
Configuration	115kV, single circuit	
Distance (mi)	10	

PLANT PERFORMANCE

Net Capacity and Heat Rate:	Capacity (MW)	Heat Rate (Btu/kWh)	
Maximum Sustainable Capacity	Not specified	Not specified	
Rated Capacity	25	15000	Note 2
Minimum Sustainable Capacity	Not specified	Not specified	

Availability:		
Routine Inspection and Maintenance (days/year)	Not Specified	
Major Inspection and Overhaul (days/frequency)	Not Specified	
Average Planned Outage (days/year)	30	Note 3
Other Planned and Unplanned Outages (%)	5.0%	Note 3
Equivalent Annual Availability (%)	87.2%	Note 3
Service life (years)	30	Note 4

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25 MW WOOD RESIDUE POWER PLANT
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PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 5

Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	24	Note 6
Equipment Procurement and Construction (months)	24	Note 6
Construction Cash Flow (% by year)	25/50/25	Note 7

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Siting & Licensing	SL1	2% TPC, Battelle(82) p.6.27	1/90	0.759	n/a	100	100	0.759	$30
	SL2			0.000	n/a	100	100	0.000	$0
	SL3			0.000	n/a	100	100	0.000	$0
	SL4			0.000	n/a	100	100	0.000	$0
	SL5			0.000	n/a	100	100	0.000	$0
	SL6			0.000	n/a	100	100	0.000	$0
Total Siting & Lic.	TSL							0.759	$30

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 8	1/86	0.050	GNP	1.124	1.288	0.057	$2.29
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84)	1/84	0.001	GNP	1.058	1.288	0.001	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84)	1/84	0.004	GNP	1.058	1.288	0.004	$0.17
Land Option	OH4	N/A, land is purchased	n/a	0.000	n/a	100	100	0.000	$0.00
Owner's Indirects	OH5	11% OH1-4, Henriques(84)	1/90	0.007	n/a	100	100	0.007	$0.28
Total Annual Hold Costs	THC							0.070	$2.79

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PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 9)								
Land Acquisition	DC1	Included in SL1	n/a	0.000	n/a	100	100	0.000	$0
Civil/Structural	DC2	NWPPC(89a) T.9	7/89	3.177	HW6	306	311	3.229	$129
Turbine-Generator	DC3	NWPPC(89a) T.9	7/89	5.025	HW6	306	311	5.107	$204
Steam Generator	DC4	NWPPC(89a) T.9	7/89	6.590	HW6	306	311	6.698	$268
Fuel & Ash Handling	DC5	NWPPC(89a) T.9	7/89	2.670	HW6	306	311	2.714	$109
Air Pollution Control	DC6	NWPPC(89a) T.9	7/89	1.094	HW6	306	311	1.112	$44
Piping/Insulation/Lagging	DC7	NWPPC(89a) T.9	7/89	2.663	HW6	306	311	2.707	$108
Mechanical & Other	DC8	NWPPC(89a) T.9	7/89	3.420	HW6	306	311	3.476	$139
Electrical	DC9	NWPPC(89a) T.9	7/89	1.779	HW6	306	311	1.808	$72
Total Direct Cost	TDC							26.850	$1,074
Indirect Costs:									
Indirect Const. Costs	IC1	NWPPC(89a) T.9	7/89	0.756	HW6	306	311	0.768	$31
Engineering	IC2	NWPPC(89a) T.9	7/89	3.990	HW6	306	311	4.055	$162
Contingency	IC3	Note 10	1/90	4.143	n/a	100	100	4.143	$166
Owner's Cost	IC4	Note 11	1/90	1.433	n/a	100	100	1.433	$57
	IC5								
	IC6								
Total Indirect Cost	TIC							10.399	$416
Burdened Costs:									
Switchyard	BC1	Included in DC (Ebasco(84))	n/a	0.000	n/a	100	100	0.000	$0
Trans. Interconnect	BC2	Note 12	1/90	0.188	n/a	100	100	0.188	$8
Spares	BC3	Assume 0.5% of TDC	1/90	0.134	n/a	100	100	0.134	$5
Prepaid royalties	BC4	n/a	n/a	0.000	n/a	100	100	0.000	$0
SE Impact Mitigation	BC5	1% of TPC, COTF	1/90	0.379	n/a	100	100	0.379	$15
	BC6		n/a	0.000	n/a	100	100	0.000	$0
Total Burdened Cost	TBC							0.701	$28
Total Plant Cost	TPC	TDC + TIC + TBC						37.950	$1,518

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PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		60	days	1.387	$55
Secondary Fuel Inventory	FI2		0	days	0.000	$0
Total Fuel Inventory Cost	TFI				1.387	$55
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	0.090	$4
Variable O&M	SU2	EPRI standard assumption	30	days	0.066	$3
Fixed Fuel	SU3	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU4	EPRI standard assumption	7	days	0.162	$6
Equip. Modification	SU5	EPRI standard assumption	2.0%	percent total plant cost	0.759	$30
Total Startup Cost:	TSU				1.077	$43
Total Preproduction Cost	TPPC	TFI + TSU			2.464	$99

CAPITAL COST SUMMARY

Siting & Licensing	0.759	$30
Plant	37.950	$1,518
Preproduction	2.464	$99
Total Overnight Capital Costs	41.173	$1,647

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 13	7/89	42.910	GNPD	126.3	128.8	$43.76
Var. O&M (m/kWh)	OC2	Note 14	7/89	3.250	GNPD	126.3	128.8	3.3
Consumables (m/kWh)	OC3	Note 15	7/89	0.360	GNPD	126.3	128.8	0.4
Byproduct Credit (m/kWh)	OC4	None	n/a	0.0	n/a	100	100	0.0
Cap. Rep. ($/kW/yr)	OC5	Inc. in OC1	n/a	$0.00	n/a	100	100	$0.00
Decomissioning	OC6	Assumed to net zero	n/a	$0.00	n/a	100	100	$0.00

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NOTES

1. Fuel information, quantity and price from NWPPC(89a) and NWPPC(90); escalation indices from NWPPC(91):

	Quantity (TBtu/yr)	Variable Price ($1988) ($/MMBtu)	Escal-ation Factor	Variable Price ($1990) ($/MMBtu)	Fixed Price ($1990) ($/kW/yr)	Escl. (Real) (%/yr)
Municipal Solid Waste	0	-$6.50	1.08	-$7.01	$0.00	0.0%
Logging Residue	4	$3.30	1.08	$3.56	$0.00	0.0%
Mill Residue	2	$1.00	1.08	$1.08	$0.00	0.0%
Agricultural Residue	5	$2.20	1.08	$2.37	$0.00	0.0%
Stand-alone Mix	11	$2.38	1.08	$2.57	$0.00	0.0%

2. Heat rate is from NWPPC(89a) Table 9.

3. Scheduled and unscheduled outage estimates are from Battelle(82b) Table 3.4. Battelle uses an 87% availability; the availability shown here is calculated using EPRI methods. A conservative availability of 80% is used in the resource assessment of this plan.

4. From Battelle(82b) Table 3.4.

5. Constant energy output is assumed here. Actual output might vary seasonally due to availability of fuel.

6. Based on 26 months from Battelle(82a) Figure 5.2; rounded to two years for modeling purposes.

7. S-shaped symmetrical payout.

8. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

9. Sales tax is not included in cost estimates.

10. Project contingency is 15% of total direct costs (TDC) and indirect construction costs (IC1); from NWPPC(89a) T.9.

11. Owners costs are 4% of total direct costs and other indirect costs (IC1-3); from PNUCC(84).

12. Transmission costs assumed to be $0.75/kW/mile, $1990 (Rounded from IP89-36 T. 3-5).

13. Fixed operating and maintenance costs are from NWPPC(89a) T.9, as follows ($1989/kW):

Power Plant Operations	$20.09
Fuel handling Operations	$5.74
Pollution Control Operations	$2.87
Power Plant Maintenance	$8.53
Fuel Handling Maintenance	$2.84
Pollution Control Maintenance	$2.84
Total Fixed Operation and Maintenance Costs	$42.91

14. Variable operating and maintenance costs are from NWPPC(89a) T.9, as follows (1989 mills/kWh):

Waste Disposal	3.0

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Northwest Power Planning Council Representative Power Plant
25 MW WOOD RESIDUE POWER PLANT
(Direct-fired Steam-electric)
January 1990 Base Year

Maintenance Labor	0.2
Total Variable Operation and Maintenance Costs	3.3

15. Consumables costs are from NWPPC(89a) T.9, as follows (1989 mills/kWh):

Water Consumption and Treatment	0.0
Chemicals	0.3
Total Consumables Costs	0.4

REFERENCES

Battelle (82a): Battelle, Pacific Northwest Laboratories. Development and Chararacterization of Electric Power Conservation and Supply Resource Planning Options. Prepared for the Northwest Power Planning Council. August, 1982.

Battelle (82b): Battelle, Pacific Northwest Laboratories. Assessment of Electric Power Conservation and Supply Resources - Volume V: Biomass. Prepared for the Northwest Power Planning Council. August, 1982.

BPA (1983): Bonneville Power Administration. Comparative Electric Generation Study, Volume I. Prepared for Bonneville Power Administration by Kaiser Engineers Power Corporation. January, 1983.

Ebasco(84): Ebasco Services Incorporated. Seattle City Light Conceptual Study for Wood Residue-fired Power Plants. October, 1984.

Henriques(84b): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

HW: Handy-Whitman Index of Public Utility Construction Costs

NWPPC(91): Northwest Power Planning Council. Memorandum from Terry Morlan to Power Division Staff, Deflators for the 91 Power Plan. January 4, 1991.

NWPPC(90): Northwest Power Planning Council. Biomass Fuels (Decision Memo of January 2, 1990).

NWPPC(89a): Northwest Power Planning Council. Biomass Resources (Staff Issue Paper 89-41). Prepared by James D. Kerstetter of the Washington State Energy office for the Northwest Power Planning Council. October 1989.

NWPPC(89b): Northwest Power Planning Council. Geothermal Resources (Staff Issue Paper 89-36). Prepared by John D. Geyer through a contract with the Washington State Energy office for the Northwest Power Planning Council. October 1989.

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Northwest Power Planning Council Representative Power Plant
10 MW MUNICIPAL SOLID WASTE POWER PLANT
(Mass Burn)
January 1990 Base Year

GENERAL PLANT DESCRIPTION

Type:	Mass-burn steam-electric	
Configuration:	One 10MW unit	
Site:	Not specified	
Primary Fuel:	Municipal Solid Waste	
Heat Value (Btu/lb, HHV)	4500	
Delivery	Truck	
Inventory (days)	None	
Fixed Cost ($/kW/yr)	$0.00	
Variable Cost ($/MMBtu)	-$7.01	Note 1
Alternate Fuel:	None	
Heat Value (Btu/lb, HHV)	n/a	
Delivery	n/a	
Inventory (days)	None	
Fixed Cost ($/kW/yr)	n/a	
Variable Cost ($/MMBtu)	n/a	
Environmental Controls:		
Heat Rejection	Mechanical draft cooling towers	
Air Emission Controls	Not specified	
Grid Interconnection:		
Configuration	Not specified	
Distance (mi)	Not specified	

PLANT PERFORMANCE

Net Capacity and Heat Rate:	Capacity (MW)	Heat Rate (Btu/kWh)	
Maximum Sustainable Capacity	Not specified	Not specified	
Rated Capacity	10	20000	Note 2
Minimum Sustainable Capacity	Not specified	Not specified	

Availability:		
Routine Inspection and Maintenance (days/year)	Not Specified	
Major Inspection and Overhaul (days/frequency)	Not Specified	
Average Planned Outage (days/year)	21	Note 3
Other Planned and Unplanned Outages (%)	7.0%	Note 3
Equivalent Annual Availability (%)	87.6%	Note 3
Service life (years)	30	Note 4

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Northwest Power Planning Council Representative Power Plant
10 MW MUNICIPAL SOLID WASTE POWER PLANT
(Mass Burn)
January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 5

Month	Percent
Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	27	Note 6
Equipment Procurement and Construction (months)	36	Note 6
Construction Cash Flow (% by year)	25/50/25	Note 7

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Siting & Licensing	SL1	4% TPC, Battelle(82a) p.6.30	1/90	2.045	n/a	100	100	2.045	$204
	SL2			0.000	n/a	100	100	0.000	$0
	SL3			0.000	n/a	100	100	0.000	$0
	SL4			0.000	n/a	100	100	0.000	$0
	SL5			0.000	n/a	100	100	0.000	$0
	SL6			0.000	n/a	100	100	0.000	$0
Total Siting & Lic.	TSL							2.045	$204

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 8	1/86	0.050	GNP	1.124	1.288	0.057	$5.73
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84)	1/84	0.000	GNP	1.058	1.288	0.000	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84)	1/84	0.001	GNP	1.058	1.288	0.002	$0.17
Land Option	OH4	N/A, land is purchased.	n/a	0.000	n/a	100	100	0.000	$0.00
Owner's Indirects	OH5	11% OH1-4, Henriques(84)	1/90	0.007	n/a	100	100	0.007	$0.65
Total Annual Hold Costs	THC							0.066	$6.60

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Northwest Power Planning Council Representative Power Plant
10 MW MUNICIPAL SOLID WASTE POWER PLANT
(Mass Burn)
January 1990 Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 9)								
Land Acquisition	DC1	Inc. in SL1	n/a	0.000	n/a	100	100	0.000	$0
Plant Construction	DC2	Battelle(82b), p.4.8	1/80	33.200	HW6	202	311	51.115	$5,111
	DC3		n/a	0.000	n/a	100	100	0.000	$0
	DC4		n/a	0.000	n/a	100	100	0.000	$0
	DC5		n/a	0.000	n/a	100	100	0.000	$0
	DC6		n/a	0.000	n/a	100	100	0.000	$0
	DC7		n/a	0.000	n/a	100	100	0.000	$0
	DC8		n/a	0.000	n/a	100	100	0.000	$0
	DC8		n/a	0.000	n/a	100	100	0.000	$0
	DC9		n/a	0.000	n/a	100	100	0.000	$0
Total Direct Cost	TDC							51.115	$5,111
Indirect Costs:			Base	Percent					
Contractor O&P	IC1	Included in direct costs	n/a	0.000	n/a	100	100	0.000	$0
Engineering	IC2	Included in direct costs	n/a	0.000	n/a	100	100	0.000	$0
Construction Management	IC3	Included in direct costs	n/a	0.000	n/a	100	100	0.000	$0
Contingency	IC4	Included in direct costs	n/a	0.000	n/a	100	100	0.000	$0
Owner's Cost	IC5	Included in direct costs	n/a	0.000	n/a	100	100	0.000	$0
	IC6							0.000	$0
Total Indirect Cost	TIC							0.000	$0
Burdened Costs:									
Switchyard	BC1	Inc. in directs	n/a	0.000	n/a	100	100	0.000	$0
Trans. Interconnect	BC2	Inc. in directs	n/a	0.000	n/a	100	100	0.000	$0
Spares	BC3	Inc. in directs	n/a	0.000	n/a	100	100	0.000	$0
Prepaid royalties	BC4	Inc. in directs	n/a	0.000	n/a	100	100	0.000	$0
SE Impact Mitigation	BC5	Inc. in directs	n/a	0.000	n/a	100	100	0.000	$0
	BC6		n/a	0.000	n/a	100	100	0.000	$0
Total Burdened Cost	TBC							0.000	$0
Total Plant Cost	TPC	TDC + TIC + TBC						51.115	$5,111

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Northwest Power Planning Council Representative Power Plant
10 MW MUNICIPAL SOLID WASTE POWER PLANT
(Mass Burn)
January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		0	days	0.000	$0
Secondary Fuel Inventory	FI2		0	days	0.000	$0
Total Fuel Inventory Cost	TFI				0.000	$0
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	0.357	$36
Variable O&M	SU2	EPRI standard assumption	30	days	0.000	$0
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	-0.236	-$24
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	1.022	$102
Total Startup Cost:	TSU				1.143	$114
Total Preproduction Cost	TPPC	TFI + TSU			1.143	$114

CAPITAL COST SUMMARY

	MM$	$/kW
Siting & Licensing	2.045	$204
Plant Construction	51.115	$5,111
Preproduction	1.143	$114
Total Overnight Capital Costs	54.303	$5,430

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Battelle(82b) T.4-8	1/80	$220.00	GNPD	84	128.8	$337.33
Var. O&M (m/kWh)	OC2	Inc. in OC1	n/a	0.0	GNPD	84	128.8	0.0
Consumables (m/kWh)	OC3	Inc. in OC1	n/a	0.0	GNPD	84	128.8	0.0
Byproduct Credit (m/kWh)	OC4	Inc. in OC1	n/a	0.0	GNPD	84	128.8	0.0
Cap. Rep. ($/kW/yr)	OC5	Battelle(82b) T.4-8	n/a	$62.00	GNPD	84	128.8	$95.07
Decomissioning ($/kW/yr)	OC6	From Coal Costsheets	1/90	$1.65	n/a	100	100	$1.65

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Northwest Power Planning Council Representative Power Plant
10 MW MUNICIPAL SOLID WASTE POWER PLANT
(Mass Burn)
January 1990 Base Year

NOTES

1. Typical tipping fee. From NWPPC, 1989, escalated to 1990 dollars using GNP deflator:

Tip Fee ($1988)	GNPD (1/88)	GNPD (1/90)	Tip Fee ($1990)
$6.50	119.40	128.80	$7.01

2. Heat rate from Battelle(82b), Table 3.4.

3. Scheduled and unscheduled outage estimates are from Battelle(82b). Battelle uses an 87% availability; the availability shown here is calculated using EPRI methods. A conservative availability of 80% is used in the resource assessment of this plan.

4. From Battelle(82b), Table 3.4.

5. Actual energy production potential may exhibit a summertime peak.

6. From Battelle(82a) Figure 5.3. Siting and licensing may take much longer than shown.

7. S-shaped, symmetrical payout.

8. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

9. Sales tax is excluded from cost estimates.

REFERENCES

Battelle (82a): Battelle, Pacific Northwest Laboratories. Development and Chararacterization of Electric Power Conservation and Supply Resource Planning Options. Prepared for the Northwest Power Planning Council. August, 1982.

Battelle (82b): Battelle, Pacific Northwest Laboratories. Assessment of Electric Power Conservation and Supply Resources - Volume V: Biomass. Prepared for the Northwest Power Planning Council. August, 1982.

Henriques(84): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

HW: Handy-Whitman Index of Public Utility Construction Costs

Northwest Power Planning Council Representative Power Plant

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PLANT DESCRIPTION

Type:		Simple-cycle gas turbine generator power plant
Configuration:		Two 146 MW GE MS7001F GTGs
Site:		Hermiston, Oregon
Primary Fuel:		Natural gas
Heat Value (Btu/lb, HHV)		1000
Delivery		Pipeline
Inventory (days)		None
Fixed Cost ($/kW/yr)		$0.00
Variable Cost ($/MMBtu)		$3.16
Alternate Fuel:		Distillate fuel oil
Heat Value (Btu/lb, HHV)		19430
Delivery		Truck, barge, pipeline or rail
Inventory (days)		14
Fixed Cost ($/kW/yr)		$0.00
Variable Cost ($/MMBtu)		$4.87
Environmental Controls: (Note 14)		
Heat Rejection		Direct to atmosphere
Air Emission Controls	SOx:	Low-sulfur fuel oil
	NOx:	Water injection
Grid Interconnection:		
Configuration		230kV, single circuit
Distance (mi)		10

PLANT PERFORMANCE

Net Capacity and Heat Rate (Higher Heat Value of fuel):	Capacity (MW)	Heat Rate (Btu/kWh)	
35F ambient air temperature	304.6	11228	Note 1
59F ambient air temperature	278.5	11596	Note 1
88F ambient air temperature	246.4	12101	Note 1

Availability:		
Routine Inspection and Maintenance (days/year)	30	Note 2
Major Inspection and Overhaul (days/frequency)	90 days @ five-year intervals	Note 2
Average Annual Maintenance and Outage (days/year)	42	Note 2
Other Planned and Unplanned Outages (%)	4.0%	Note 2
Equivalent Annual Availability (%)	85.0%	Note 2
Service life (years)	30	Note 3

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Northwest Power Planning Council Representative Power Plant

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 4

Month	Percent
Jan	9.0%
Feb	8.8%
Mar	8.6%
Apr	8.3%
May	8.1%
Jun	7.9%
Jul	7.6%
Aug	7.7%
Sep	8.0%
Oct	8.3%
Nov	8.7%
Dec	8.9%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	24	Notes 5, 17
Equipment Procurement and Construction (months)	24	Note 5
Construction Cash Flow (% by year)	48/52	Note 6

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Land Option	SL1	Battelle(82) 15% of DC1	1/90	0.069	n/a	100	100	0.069	$0
Feasibility Studies	SL2	Battelle(82) 1% of TPC	1/90	1.713	n/a	100	100	1.713	$6
Env. Baseline, Licenses	SL3	Included in SL2	n/a	0.000	n/a	100	100	0.000	$0
	SL4			0.000	n/a	100	100	0.000	$0
	SL5			0.000	n/a	100	100	0.000	$0
	SL6			0.000	n/a	100	100	0.000	$0
Total Siting & Lic.	TSL							1.782	$6

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 7	1/86	0.050	GNP	1.124	1.288	0.057	$0.21
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84)	1/84	0.011	GNP	1.058	1.288	0.014	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84)	1/84	0.039	GNP	1.058	1.288	0.047	$0.17
Land Option	OH4	Note 8	1/90	0.069	n/a	100	100	0.069	$0.25
Owner's Indirects	OH5	11% OH1-4, Henriques(84)	1/90	0.021	n/a	100	100	0.021	$0.07
Total Annual Hold Costs	THC							0.208	$0.75

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Northwest Power Planning Council Representative Power Plant

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 9)								
Land	DC1	Fluor(88) T.6-8 (20A)	1/86	0.400	GNPD	112.4	128.8	0.458	$2
Power Generation	DC2	Fluor(88) T.5-1,2	1/88	76.069	HW30	276	346	95.362	$342
General Facilities	DC3	Fluor(88) T.5-1,2	1/88	39.587	HW7	260	276	42.023	$151
Fuel Oil System	DC4	Note 15	11/85	5.039	HW29	256	306	6.023	$22
Cats and Chemicals	DC5	Fluor(88) T.5-1,2	1/88	0.048	HW14	301	324	0.052	$0
	DC6			0.000	n/a	100	100	0.000	$0
	DC8			0.000	n/a	100	100	0.000	$0
	DC9			0.000	n/a	100	100	0.000	$0
	DC10			0.000	n/a	100	100	0.000	$0
Total Direct Cost	TDC							143.918	$517
Indirect Costs:									
Contractor O&P	IC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Engineering	IC2	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Construction Management	IC3	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Contingency	IC4	Fluor(88) T.5-2, 10% TDC	1/90	14.392	n/a	100	100	14.392	$52
Owner's Cost	IC5	PNUCC(84), 4% of TDC+IC4	1/90	6.332	n/a	100	100	6.332	$23
	IC6			0.000	n/a	100	100	0.000	$0
Total Indirect Cost	TIC							20.724	$74
Burdened Costs:									
Switchyard	BC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Trans. Interconnect	BC2	BPA, 10mi 230kV sgl ckt	1/87	2.570	HW33	252	297	3.029	$11
Spares	BC3	Fluor(88) T.6-8 (0.5% TPC)	1/90	0.857	n/a	100	100	0.857	$3
Prepaid royalties	BC4	Fluor(88) T.6-8 (None))	n/a	0.000	n/a	100	100	0.000	$0
Impact Mitigation	BC5	1% of TPC (Note 16)	1/90	1.713	n/a	100	100	1.713	$6
Fuel Supply	BC6	2 mi pipeline, $0.5/mi	1/88	1.000	GNPD	119.4	128.8	1.079	$4
Total Burdened Cost	TBC							6.677	$24
Total Plant Cost	TPC	TDC + TIC + TBC						171.320	$615

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Northwest Power Planning Council Representative Power Plant

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		0	days	0.000	$0
Secondary Fuel Inventory	FI2		14	days	5.284	$19
Total Fuel Inventory Cost	TFI				5.284	$19
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	0.050	$0
Variable O&M	SU2	EPRI standard assumption	30	days	0.029	$0
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	1.714	$6
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	3.426	$12
Total Startup Cost:	TSU				5.220	$19
Total Preproduction Cost	TPPC	TFI + TSU			10.504	$38

CAPITAL COST SUMMARY

Siting & Licensing		1.782	$6
Plant		171.320	$615
Preproduction		10.504	$38
Total Overnight Capital Costs	(Note 17)	183.606	$659

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 10	1/88	2.01	GNPD	119.4	128.8	$2.17
Var. O&M (m/kWh)	OC2	Note 11	1/88	0.12	GNPD	119.4	128.8	0.1
Consumables (m/kWh)	OC3	Note 12	1/88	0.02	GNPD	119.4	128.8	0.0
Byproduct Credit (m/kWh)	OC4	None	n/a	0.00	n/a	100	100	0.0
Cap. Rep. ($/kW/yr)	OC5	Included in OC1	n/a	$0.00	n/a	100	100	$0.00
Decomissioning	OC6	Note 13	n/a	$0.00	n/a	100	100	$0.00

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Northwest Power Planning Council Representative Power Plant

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

NOTES

1. From Fluor(88), Table 3-2, as corrected by Fluor(89), Table 1.

2. Availability assumptions are from 1986 Power Plan (NWPPC(86)).

3. Expected physical life when operated primarily for backing-up non-firm hydropower and with major overhauls at ten-year intervals.

4. Seasonality is due to ambient air temperature effects on combustion turbine output. From Figure 3.1 of BPA(86) using mean monthly temperature of Arlington, Oregon from NOAA(82).

5. Based on Puget Sound Power and Light construction experience with the Fredonia plant, as reported in PNUCC(84).

6. From Fluor(88) Table 5-4, adjusted to the nearest year.

7. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

8. Annual land option hold cost is estimated to be 15% of total land cost, based on Washington Water Power experience at the Creston site.

9. Cost estimates exclude sales tax.

10. Fixed O&M costs (1988$):

	(1000$/yr)
Standby maintenance material, Fluor(88) T.6-3	12.000
12 mo. base load operating labor, Fluor(88) T.6-4	175.000
12 mo. base load maintenance labor, Fluor(88) T.6-4	175.000
12 mo. base load admin & support labor, Fluor(88) T.6-4	116.000
Subtotal:	478.000
General and Administrative Costs (Home Office) (17%, PNL(85))	81.260
Total fixed O&M costs:	559.260

11. Variable O&M costs (1988$):

	(1000$/yr)	(mills/kWh)
Incremental 12-month base load maintenance material *	251.000	0.103
Subtotal variable costs	251.000	0.103
General and Administrative Costs (Home Office) (17%, PNL(85))	42.670	0.017
Total variable O&M costs	293.670	0.120

* (Fluor(88) T.6-4 less T.6-3)

12. Consumables costs (1988$):

	(mills/kWh)
Water, catalyst & chemicals, Fluor(88) T.6-6	0.013
Subtotal consumable costs	0.013
General and Administrative Costs (Home Office) (17%, PNL(85))	0.002
Total consumable costs	0.015

13. Salvage value is assumed to offset decomissioning costs.

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

14. The environmental emissions for the representative plant, operating on natural gas fuel are as listed below (35F rating temperature, from Fluor(88) T.4-1):

	(lb/hr)	(T/MW/yr)	
SOx	2	0.03	
NOx	1290	18.55	*
CO	60	0.86	
Particulates (to atmosphere)	20	0.29	
Solid waste	Not significant		
Water discharge	Not significant		

* 75 ppmv; can be reduced further by additional water injection.

15. Fuel oil system costs were not included in the plant design basis of Fluor(88). Fuel oil system costs were obtained by scaling the estimates of auxilliary fuel oil system costs of BPA(87).

16. Based on Washington Water Power estimates for the Creston project.

17. The capital costs and siting and licensing schedules shown exclude costs and schedule effects of preparing the site for eventual conversion to coal gasification. A "gasifier-ready" combustion turbine power plant would require additional environmental assessment and other licensing activity to certify the site suitable for coal gasification; acquisition of additional land to accomodate the gasification plant and coal handling and storage facilities; and common facilities sized to accomdate requirements of a gasification plant. The costs and schedule of a "gasifier-ready" combustion turbine power plant would differ from the base case as follows:

Siting and Licensing Period (months)	48
Siting and Licensing Cost ($/kW)	$62.00
Option Hold ($/kW/yr)	$2.53
Plant Costs ($/kW)	$619.00
Pre-production Costs ($/kW)	$38.00

REFERENCES

Battelle (82): Battelle, Pacific Northwest Laboratories. Development and Chararacterization of Electric Power Conservation and Supply Resource Planning Options. Prepared for the Northwest Power Planning Council. August, 1982.

BPA(87): Bonneville Power Administration. Comparative Electric Generation Study, Coal-fired Power Plants. Prepared by Kaiser Engineers. October 1987.

BPA(86): Bonneville Power Administration. Comparative Electric Generation Study, Coal Gasification, Shell Gasification-based Phasing Study. Prepared by Fluor Technology, Inc. November, 1986.

Fluor(89): Fluor Daniel, Inc. Comparison and Reconciliation of "Coal Gasification: Conversion of Medium Btu Gas to Electrical Energy, Shell Gasification - based Phasing Study" and "Development of Combustion Turbine Capital and Operating Costs". Prepared for the Bonneville Power Administration, Portland, Oregon. December 1989.

Fluor(88): Fluor Daniel, Inc. Development of Combustion Turbine Capital and Operating Costs. Prepared for the Bonneville Power Administration, Portland, Oregon. July 1988.

NOAA(82): National Oceanic and Atmospheric Administration. Monthly Normals of Temperature, Precipitation and Heating and Cooling Degree Days: 1951-1980. 1982.

2 X 139 MW SIMPLE-CYCLE COMBUSTION TURBINE

January 1990 Base Year

Henriques(84): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

HW: Handy-Whitman Index of Public Utility Construction Costs

NWPPC(86): Northwest Power Planning Council. 1986 Northwest Conservation and Electric Power Plan. January 1986.

PNL(85): Pacific Northwest Laboratory. Electric Energy Supply Systems: Description of Available Technologies. February, 1985.

PNUCC(84): Pacific Northwest Utilities Conference Committee. "Working Paper, Development of Generic Resource Data". October 1984.

11-SEP-91 Northwest Power Planning Council Representative Power Plant

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PLANT DESCRIPTION

Type:		Combined-cycle gas turbine generator power plant General Electric STAG 207F	
Configuration:		Two 146MW GE MS7001F GTGs; one 208MW steam TG	
Site:		Hermiston, Oregon	
Primary Fuel:		Natural gas	
Heat Value (Btu/lb, HHV)		1000	
Delivery		Pipeline	
Inventory (days)		None	
Fixed Cost ($/kW/yr)		$0.00	
Variable Cost ($/MMBtu)		$3.16	
Alternate Fuel:		Distillate fuel oil	
Heat Value (Btu/lb, HHV)		19430	
Delivery		Truck, barge, pipeline or rail	
Inventory (days)		14	
Fixed Cost ($/kW/yr)		$0.00	
Variable Cost ($/MMBtu)		$4.87	
Environmental Controls: (Note 15)			
Heat Rejection		Wet mechanical draft cooling towers	Note 1
Air Emission Controls	SOx:	Low-sulfur fuel oil	
	NOx:	Water injection	
Grid Interconnection:			
Configuration		230kV, double circuit	
Distance (mi)		10	

PLANT PERFORMANCE

Net Capacity and Heat Rate (Higher Heat Value of fuel):	Capacity (MW)	Heat Rate (Btu/kWh)	
35F ambient air temperature	452.2	7500	Note 2
59F ambient air temperature	419.6	7620	Note 2
88F ambient air temperature	377.7	7810	Note 2

Availability:		
Routine Inspection and Maintenance (days/year)	30	Note 3
Major Inspection and Overhaul (days/frequency)	90 days @ five-year intervals	Note 3
Average Annual Maintenance and Outage (days/year)	42	Note 3
Other Planned and Unplanned Outages (%)	6.0%	Note 3
Equivalent Annual Availability (%)	83.2%	Note 3
Service life (years)	30	Note 4

11-SEP-91 Northwest Power Planning Council Representative Power Plant

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 5

Jan	9.2%
Feb	9.0%
Mar	8.8%
Apr	8.7%
May	8.4%
Jun	8.3%
Jul	8.1%
Aug	8.1%
Sep	8.3%
Oct	8.7%
Nov	8.9%
Dec	9.1%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	24	Notes 6,18,19
Equipment Procurement and Construction (months)	36	Note 7
Construction Cash Flow (% by year)	48/52	Note 7

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Land Option	SL1	Battelle(82) 15% of DC1	1/90	0.069	n/a	100	100	0.069	$0
Feasibility Studies	SL2	Battelle(82) 1% of TPC	1/90	3.044	n/a	100	100	3.044	$7
Env. Baseline, Licenses	SL3	Included in SL2	n/a	0.000	n/a	100	100	0.000	$0
	SL4			0.000	n/a	100	100	0.000	$0
	SL5			0.000	n/a	100	100	0.000	$0
	SL6			0.000	n/a	100	100	0.000	$0
Total Siting & Lic.	TSL							3.113	$7

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 8	1/86	0.050	GNP	1.124	1.288	0.057	$0.14
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84)	1/84	0.017	GNP	1.058	1.288	0.020	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84)	1/84	0.059	GNP	1.058	1.288	0.072	$0.17
Land Option	OH4	Note 9	1/90	0.069	n/a	100	100	0.069	$0.16
Owner's Indirects	OH5	11% OH1-4, Henriques(84)	1/90	0.024	n/a	100	100	0.024	$0.06
Total Annual Hold Costs	THC							0.242	$0.58

11-SEP-91

Northwest Power Planning Council Representative Power Plant

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 10)								
Land	DC1	Fluor(88) T.6-8 (20A)	1/86	0.400	GNPD	112.4	128.8	0.458	$1
Power Generation	DC2	Fluor(88) T.5-1,2,3	1/88	152.616	HW30	276	346	191.323	$456
General Facilities	DC3	Fluor(88) T.5-1,2,3	1/88	56.013	HW7	260	276	59.460	$142
Fuel Oil Storage	DC4	Note 16	11/85	5.036	HW29	256	306	6.020	$14
Cats and Chemicals	DC5	Fluor(88) T.5-1,2,3	1/88	0.083	HW14	301	324	0.089	$0
	DC6			0.000	n/a	100	100	0.000	$0
	DC8			0.000	n/a	100	100	0.000	$0
	DC9			0.000	n/a	100	100	0.000	$0
	DC10			0.000	n/a	100	100	0.000	$0
Total Direct Cost	TDC							257.350	$613
Indirect Costs:									
Contractor O&P	IC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Engineering	IC2	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Construction Management	IC3	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Contingency	IC4	Fluor(88) T.5-2, 10% TDC	1/90	25.735	n/a	100	100	25.735	$61
Owner's Cost	IC5	PNUCC(84), 4% of TDC+IC4	1/90	11.323	n/a	100	100	11.323	$27
	IC6			0.000	n/a	100	100	0.000	$0
Total Indirect Cost	TIC							37.058	$88
Burdened Costs:									
Switchyard	BC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Trans. Interconnect	BC2	BPA, 10mi 230kV dbl ckt	1/87	3.710	HW33	252	297	4.373	$10
Spares	BC3	Fluor(88) T.6-8 (0.5% TPC)	1/90	1.522	n/a	100	100	1.522	$4
Prepaid royalties	BC4	Fluor(88) T.6-8 (None))	n/a	0.000	n/a	100	100	0.000	$0
Impact Mitigation	BC5	1% of TPC (Note 17)	1/90	3.044	n/a	100	100	3.044	$7
Fuel Supply	BC6	2 mi pipeline, $0.5/mi	1/88	1.000	GNPD	119.4	128.8	1.079	$3
Total Burdened Cost	TBC							10.018	$24
Total Plant Cost	TPC	TDC + TIC + TBC						304.426	$726

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		0	days	0.000	$0
Secondary Fuel Inventory	FI2		14	days	5.232	$12
Total Fuel Inventory Cost	TFI				5.232	$12
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	0.200	$0
Variable O&M	SU2	EPRI standard assumption	30	days	0.112	$0
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	1.697	$4
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	6.089	$15
Total Startup Cost:	TSU				8.098	$19
Total Preproduction Cost	TPPC	TFI + TSU			13.330	$32

CAPITAL COST SUMMARY

Siting & Licensing		3.113	$7
Plant		304.426	$726
Preproduction		13.330	$32
Total Overnight Capital Costs	(Notes 1,18,19)	320.869	$765

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 11	1/88	5.38	GNPD	119.4	128.8	$5.81
Var. O&M (m/kWh)	OC2	Note 12	1/88	0.243	GNPD	119.4	128.8	0.3
Consumables (m/kWh)	OC3	Note 13	1/88	0.1	GNPD	119.4	128.8	0.1
Byproduct Credit (m/kWh)	OC4	None	n/a	0.000	n/a	100	100	0.0
Cap. Rep. ($/kW/yr)	OC5	Included in OC1	n/a	$0.00	n/a	100	100	$0.00
Decomissioning	OC6	Note 14	n/a	$0.00	n/a	100	100	$0.00

11-SEP-91 Northwest Power Planning Council Representative Power Plant

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

NOTES

1. The base case power plant includes mechanical draft cooling towers. Arid sites may require dry condenser cooling.

   A dry condenser cooling system is estimated to cost three times the cost of a wet mechanical draft cooling system. This increases direct power plant costs by $11.8 million. The fan load of a dry cooling system is estimated to be four times the fan load of a wet mechanical draft system, and the raw water pumping load of a dry cooling system is estimated to be one-fourth that of a wet system. The net effect on auxilliary loads would be an increase of 1.0 megawatt. The dry cooling system is assumed to be as effective as a wet system.

   The cost and performance effects of providing dry cooling are as follows:

Net capacity, 59F ambient (MW)	418.6
Heat rate at 59F ambient (Btu/kWh)	7637
Siting and Licensing ($/kW)	$8.00
Option Hold ($/kW//yr)	$0.58
Plant Costs ($/kW)	$760.00
Preproduction Costs ($/kW)	$33.00

2. From Fluor(88), Table 3-2, as corrected by Fluor(89), Table 1.

3. Availability assumptions from 1986 Power Plan. See NWPPC(86) for derivation.

4. Expected physical life when operated primarily for backing-up non-firm hydropower and with major overhauls at ten-year intervals.

5. Seasonality is due to ambient air temperature effects on combustion turbine output. From Figure 3.1 of BPA(86) using mean monthly temperature of Arlington, Oregon from NOAA(82).

6. Siting and licensing period is based on Puget Sound Power and Light construction experience with the Fredonia plant, as reported in PNUCC(84).

7. From Fluor(88) Table 5-4, rounded to the nearest year.

8. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

9. Annual land option hold cost is estimated to be 15% of total land cost, based on Washington Water Power experience at the Creston site.

10. Cost estimates exclude sales tax.

11. Fixed O&M costs (1988$):

	(1000$/yr)
Standby maintenance material, Fluor(88) T.6-3	24.000
12 mo. base load operating labor, Fluor(88) T.6-4	1165.000
12 mo. base load maintenance labor, Fluor(88) T.6-4	525.000
12 mo. base load admin & support labor, Fluor(88) T.6-4	216.000
Subtotal:	1930.000
General and Administrative Costs (Home Office) (17%, PNL(85))	328.100
Total fixed O&M costs:	2258.100

11-SEP-91 Northwest Power Planning Council Representative Power Plant

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

12. Variable O&M costs (1988$):

	(1000$/yr)	(mills/kWh)
Incremental 12-month base load maintenance material *	764.000	3.634
Subtotal variable costs	764.000	3.634
General and Administrative Costs (Home Office) (17%, PNL(85))	129.880	0.618
Total variable O&M costs	893.880	0.243

* (Fluor(88) T.6-4 less T.6-3)

13. Consumables costs (1988$):

	(mills/kWh)
Water, catalyst & chemicals, Fluor(88) T.6-6	0.086
Subtotal consumable costs	0.086
General and Administrative Costs (Home Office) (17%, PNL(85))	0.015
Total consumable costs	0.101

14. Salvage value is assumed to offset decomissioning costs.

15. The environmental emissions for the representative plant, operating on natural gas fuel are as listed below (35F ambient temperature, from Fluor(88) T.4-1):

	(lb/hr)	(T/MW/yr)	
SOx	2	0.02	
NOx	1290	12.49	*
CO	60	0.58	
Particulates (to atmosphere)	20	0.19	
Solid waste	Not significant		
Water discharge	106212	1028.77	**

* 75 ppmv; can be reduced further by additional water injection.
** Cooling tower blowdown and storm water runoff.

16. Fuel oil system costs were not included in the plant design basis of Fluor(88). Fuel oil system costs were obtained by scaling the estimates of auxilliary fuel oil system costs of BPA(87).

17. Based on Washington Water Power estimates for the Creston project.

18. The capital costs and siting and licensing schedules shown exclude costs and schedule effects of preparing the site for eventual conversion to coal gasification. A "gasifier-ready" combined-cycle power plant would require additional environmental assessment and other licensing activity to certify the site suitable for coal gasification; acquisition of additional land to accomodate the gasification plant and coal handling and storage facilities; and oversized common facilities to accomdate requirements of a gasification plant. The costs and schedule of a "gasifier-ready" combustion turbine power plant are estimated to be as follows:

	Base Case	Arid Site
Siting and Licensing Period (months)	48	48
Siting and Licensing ($/kW)	$41.00	$41.00
Option Hold ($/kW/yr)	$1.76	$1.76
Plant Costs ($/kW)	$729.00	$764.00
Preproduction Costs ($/kW)	$32.00	$33.00

19. The schedules and costs shown are for a complete plant. The incremental licensing schedule and costs of adding combined-cycle capability to an existing simple-cycle combustion turbine plant are provided below. The costs below are based on the net capacity shown.

11-SEP-91 Northwest Power Planning Council Representative Power Plant

1 x 420 MW COMBINED-CYCLE COMBUSTION TURBINE

January 1990 Base Year

	Base Case	Arid Site	Arid Site (Gasifier-ready)
Net Capacity, 59F ambient (MW)	420	419	419
Siting and Licensing Period (Months)	12	12	12
Siting and Licensing ($/kW)	$3.00	$4.00	$4.00
Option Hold ($/kW//yr)	$0.39	$0.40	$0.40
Plant Costs ($/kW)	$321.00	$355.00	$361.00
Pre-production Costs ($/kW)	$11.00	$12.00	$12.00

REFERENCES

BPA(87): Bonneville Power Administration. Comparative Electric Generation Study, Coal-fired Power Plants. Prepared by Kaiser Engineers. October 1987.

BPA(86): Bonneville Power Administration. Comparative Electric Generation Study, Coal Gasification, Shell Gasification-based Phasing Study. Prepared by Fluor Technology, Inc. November, 1986.

Fluor(89): Fluor Daniel, Inc. Comparison and Reconciliation of "Coal Gasification: Conversion of Medium Btu Gas to Electrical Energy, Shell Gasification - based Phasing Study" and "Development of Combustion Turbine Capital and Operating Costs". Prepared for the Bonneville Power Administration, Portland, Oregon. December 1989.

Fluor(88): Fluor Daniel, Inc. Development of Combustion Turbine Capital and Operating Costs. Prepared for the Bonneville Power Administration, Portland, Oregon. July 1988.

NOAA(82): National Oceanic and Atmospheric Administration. Monthly Normals of Temperature, Precipitation and Heating and Cooling Degree Days: 1951-1980. 1982.

Henriques(84): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

HW: Handy-Whitman Index of Public Utility Construction Costs

NWPPC(86): Northwest Power Planning Council. 1986 Northwest Conservation and Electric Power Plan. January 1986.

PNL(85): Pacific Northwest Laboratory. Electric Energy Supply Systems: Description of Available Technologies. February, 1985.

PNUCC(84): Pacific Northwest Utilities Conference Committee. "Working Paper, Development of Generic Resource Data". October 1984.

10-SEP-91 Northwest Power Planning Council Representative Power Plant

1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

PLANT DESCRIPTION

Type:		Integrated gasifier-combined cycle power plant Shell gasifier; GE STAG 207F combined-cycle power plant	
Configuration:		Three gasifier trains; two 146MW GE MS7001F GTGs; one 208 MW steam TG	
Site:		Hermiston, Oregon	
Primary Fuel:		East Kootenay bituminous coal	
Heat Value (Btu/lb, HHV)		12000	
Delivery		Rail	
Inventory (days)		90	
Fixed Cost ($/kW/yr)		$0.00	
Variable Cost ($/MMBtu)		$1.50	
Alternate Fuel:		Natural gas (Note 1)	
Heat Value (Btu/scf HHV)		1000	
Delivery		Pipeline	
Inventory (days)		None	
Fixed Cost ($/kW/yr)		$0.00	
Variable Cost ($/MMBtu)		$3.16	
Environmental Controls (Note 21):			
Heat Rejection		Mechanical draft cooling towers (Note 1)	
Air Emission Controls:	SOx:	Acid gas scrubbing & sulfur recovery	(Note 14)
	NOx:	Moisture-saturation of synthetic gas	(Note 15)
Grid Interconnection:			
Configuration		230kV, double circuit	
Distance (mi)		10	

PLANT PERFORMANCE

Net Capacity and Heat Rate:	Capacity (MW)	Heat Rate (Btu/kWh)	
Maximum Sustainable Capacity	451	9343	Note 2
Rated Capacity (@ 59F ambient air temperature)	419	9455	Note 2
Minimum Sustainable Capacity	Not available	Not available	

Availability:		
Routine Inspection and Maintenance (days/year)	30	Note 3
Major Inspection and Overhaul (days/frequency)	90 days @ five-year intervals	Note 3
Average Annual Maintenance and Outage (days/year)	42	Note 3
Other Planned and Unplanned Outages (%)	9.0%	Note 4
Equivalent Annual Availability (%)	80.5%	
Service life (years)	30	Note 5

10-SEP-91 Northwest Power Planning Council Representative Power Plant

1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 6

Jan	9.0%
Feb	8.8%
Mar	8.7%
Apr	8.5%
May	8.3%
Jun	8.1%
Jul	7.9%
Aug	7.9%
Sep	8.1%
Oct	8.5%
Nov	8.8%
Dec	8.9%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	48	Note 7
Engineering, Equipment Procurement and Construction (months)	39	Note 8
Construction Cash Flow (% by year)	12/48/40	Note 9

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Land Option	SL1	Battelle(82) 15% of DC1	1/90	0.052	n/a	100	100	0.052	$0
Easements & ROW	SL2	BPA(86b), T1-1	1/86	1.190	GNPD	112.4	128.8	1.364	$3
Owner's Costs	SL3	BPA(86b) T1-1 (1.5% TPC)	1/90	13.052	n/a	100	100	13.052	$31
Permits & Licenses	SL4	BPA(86b), T1-1	1/86	0.470	GNPD	112.4	128.8	0.539	$1
Geotechnical	SL5	BPA(86b) T1-1 (0.12% TPC)	1/90	1.044	n/a	100	100	1.044	$2
EIS	SL6	BPA(86b), T1-1	1/86	0.500	GNPD	112.4	128.8	0.573	$1
Total Siting & Lic.	TSL							16.623	$40

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 11	1/86	0.050	GNP	1.124	1.288	0.057	$0.14
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84)	1/84	0.017	GNP	1.058	1.288	0.020	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84)	1/84	0.059	GNP	1.058	1.288	0.071	$0.17
Land Option	OH4	Note 12	1/90	0.052	n/a	100	100	0.052	$0.12
Owner's Indirects	OH5	11% OH1-4, Henriques(84)	1/90	0.022	n/a	100	100	0.022	$0.05
Total Annual Hold Costs	THC							0.223	$0.53

10-SEP-91 Northwest Power Planning Council Representative Power Plant

1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 13)								
Land	DC1	BPA(86a), T.6-4 ($2000/A)	1/86	0.300	GNPD	112.4	128.8	0.344	$1
Power Generation (CCCT)	DC2	Fluor(88), T.5-1,-2,-3	1/88	152.616	HW30	276	346	191.323	$457
General Facilities (CCCT)	DC3	BPA(86a), T.5-1,-2,-3	1/86	52.406	HW7	250	276	57.856	$138
Gasifier Plant	DC4	BPA(86a), T.5-4	1/86	385.108	HW9	277	325	451.842	$1,078
Cats & Chemicals	DC5	BPA(86a), T.5-4	1/86	2.749	GNPD	112.4	128.8	3.150	$8
99% Sulfur Removal	DC6	Note 14	1/90	14.378	n/a	100	100	14.378	$34
38% Fuel Gas Saturation	DC8	Note 15	n/a	0.000	n/a	100	100	0.000	$0
	DC9			0.000	n/a	100	100	0.000	$0
	DC10			0.000	n/a	100	100	0.000	$0
Total Direct Cost	TDC							718.892	$1,716
Indirect Costs:									
Contractor O&P	IC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Engineering	IC2	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Construction Management	IC3	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Contingency	IC4	BPA(86a), T.5-4	1/90	95.613	n/a	100	100	95.613	$228
Owner's Cost	IC5	PNUCC(84), 4% of TDC+IC4	1/90	32.580	n/a	100	100	32.580	$78
	IC6			0.000	n/a	100	100	0.000	$0
Total Indirect Cost	TIC							128.193	$306
Burdened Costs:									
Switchyard	BC1	Inc. in directs	n/a	0.000	n/a	100	100	0.000	$0
Grid Intertie	BC2	10mi 230kV dbl ckt (BPA)	1/88	3.710	HW33	252	297	4.373	$10
Spares	BC3	BPA(86a), T.6-4	1/90	4.235	n/a	100	100	4.235	$10
Prepaid royalties	BC4	BPA(86a), T.6-4	1/90	4.235	n/a	100	100	4.235	$10
Impact Mitigation	BC5	1% of TPC (Note 16)	1/90	9.204	n/a	100	100	9.204	$22
Natural Gas Supply	BC6	2 mi pipeline, $0.5/mi (BPA)	1/88	1.000	n/a	100	100	1.000	$2
Total Burdened Cost	TBC							23.048	$55
Total Plant Cost	TPC	TDC + TIC + TBC						870.133	$2,077

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1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		90	days	12.831	$31
Secondary Fuel Inventory	FI2	(Note 1)	0	days	0.000	$0
Total Fuel Inventory Cost	TFI				12.831	$31
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	2.212	$5
Variable O&M	SU2	EPRI standard assumption	30	days	0.249	$1
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	0.998	$2
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	17.403	$42
Total Startup Cost:	TSU				20.862	$50
Total Preproduction Cost	TPPC	TFI + TSU			33.693	$80

CAPITAL COST SUMMARY

			Note 10	
Siting & Licensing			16.623	$40
Plant			870.133	$2,077
Preproduction			33.693	$80
Total Overnight Capital Costs		(Note 1)	920.449	$2,197

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 17	1/86	54.610	GNPD	112.4	128.8	$62.58
Var. O&M (m/kWh)	OC2	Note 18	1/86	0.140	GNPD	112.4	128.8	0.2
Consumables (m/kWh)	OC3	Note 19	1/86	0.785	GNPD	112.4	128.8	0.9
Byproduct Credit (m/kWh)	OC4	Note 14	1/86	0.204	GNPD	112.4	128.8	0.2
Cap. Rep. ($/kW/yr)	OC5	Inc. in OC1	n/a	$0.00	HW6	100	100	$0.00
Decommissioning	OC6	Note 20	1/90	$1.65	n/a	100	100	$1.65

1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

NOTES

1. The base case power plant includes mechanical draft cooling towers and natural gas as an alternate fuel. Arid, remote sites may require dry condenser cooling and distillate fuel oil alternate fuel.

   A dry condenser cooling system is estimated to cost three times the cost of a wet mechanical draft cooling system. This increases direct power plant costs by $18.3 million. The fan load of a dry cooling system is estimated to require four times the power of a wet mechanical draft system, and the raw water pumping load of a dry cooling system is estimated to be one-fourth that of a wet system. The net effect on auxilliary loads would be an increase of 1.5 megawatt. The dry cooling system is assumed to be as effective as a wet system.

   Storage for a 14-day supply of fuel oil is estimated to increase direct power plant costs by $6.0 million. A 14-day inventory of fuel oil at $4.87/MMBtu will cost $6.5 million.

   The cost and performance effects of providing dry cooling and distillate alternate fuel are provided below.

Rated capacity (MW)	418
Heat rate at rated capacity (Btu/kWh)	9486
Siting and Licensing ($/kW)	$41.00
Option Hold ($/kW//yr)	$0.61
Plant Costs ($/kW)	$2,149.00
Pre-production Costs ($/kW)	$94.00

2. Base case capacity s from BPA(86a), Table 2-3. Base case heat rate is from BPA(86a), Table 2-3, increased 2% to account for 99% sulfur removal (See Note 14).

3. Scheduled availability estimates are for simple- and combined-cycle combustion turbine power plants. The combustion turbine availability is assumed to govern the overall availability of the gasifier combined-cycle power plant.

4. Estimated unscheduled outage rate.

5. Estimated service life for the gas turbine units.

6. Seasonality is due to ambient air temperature effects on combustion turbine output. Calculated using a least squares regression on power vs ambient temperature data of Table 2-3 of BPA(86a) using mean monthly temperature data of Arlington, Oregon from NOAA(82).

7. Siting and licensing lead time for a new IGCC plant is assumed to be the same as for a pulverized coal-fired power plant Addition of gasification capability to an existing combined-cycle power plant initially licensed for conversion to coal gasification is assumed to require a 12-month permit review period.

8. From BPA(86a), Figure 5-4.

9. From BPA(86a), Table 5-5.

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1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

10. Costs shown are for a complete IGCC plant. The incremental costs of adding coal gasification to an existing "gasifier-ready" combined-cycle plant are provided below.

Because dry cooling and distillate alternate fuel capability would be installed with the combined-cycle phase of a phased construction power plant, there is assumed to be a negligable cost difference between the incremental cost of adding gasification capability to an existing combined-cycle power plant for either the base case or an arid/remote case. Because the net capacity of the arid/remote plant using dry cooling is slightly less than that of the base case plant, the per-kilowatt cost of the arid/remote plant is slightly greater than that of the base case plant.

	Base Case	Arid/Remote Case
Siting and Licensing ($/kW)	$17.00	$17.00
Option Hold ($/kW//yr)	$0.40	$0.40
Total Plant Costs ($/kW)	$1,351.00	$1,363.00
Pre-production Costs ($/kW)	$66.00	$66.00

11. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

12. Annual land option hold cost is estimated to be 15% of total land cost, based on Washington Water Power experience at the Creston site.

13. Cost estimates exclude sales tax.

14. The design basis for the reference plant of BPA(86a) is 85% sulfur removal capability. 99% removal is assumed to require a 2% increase in capital and fixed O&M cost and a 2% heat rate penalty. Byproduct credit from BPA(86a) has been increased to account for increased sulfur recovery.

15. The design basis fuel gas saturation for the reference plant is 26.2 Vol% to meet a 75 ppmv NOx emission limit. Fuel gas saturation may be increased up to 38% to further reduce NOx releases (BPA(86a), p. 1-4). This may require increased capital and O&M cost, but will also increase turbine output. No net cost or perfomance effect is assumed here.

16. Based on Washington Water Power estimates for the Creston project.

17. Fixed O&M costs (1986$):

	($/kW/yr)
Operating Labor (BPA(86a) T.6-3)	$6.57
Maintenance Labor (BPA(86a) T.6-3)	$13.29
Maintenance Materials (BPA(86a) T.6-3)	$19.94
Admin & Support Labor (BPA(86a) T.6-3)	$5.96
99% Removal Premium (Note 14)	$0.92
Subtotal:	$46.68
General & Admin (17%, PNL(85))	$7.93
Total:	$54.61

18. Variable O&M costs (1986$):

	(m/kWh)
Ash/Sludge Disposal (BPA(86a) T.6-3)	0.120
Subtotal:	0.120
General & Admin (17%, PNL(85))	0.020
Total:	0.140

1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

19. Consumables (1986$):

	(m/kWh)
Water (BPA(86a) T.6-3)	0.077
Catalysts & Chemicals (BPA(86a) T.6-3)	0.594
Subtotal:	0.671
General & Admin (17%, PNL(85))	0.114
Total:	0.785

20. Information from Williams(87) suggests that coal plant decomissioning costs may be of the same order of magnitude as nuclear decomissioning costs. Williams argues that coal plant decomissioning should cost, on a per kilowatt-hour basis, about the same as nuclear decomissioning. Review of Williams' adjustments to a coal plant decomissioning estimate (Table 3 of Williams(87)) indicates that several of Williams' adjustments may not be appropriate. Specifically: a greater contingency would likely apply to the nuclear decommissioning; unit removal costs for non-contaminated material may remain greater for nuclear because of routine surveillance for potential contamination; energy costs may be greater for nuclear because of large-scale electric cutting activities; and finally, ash pond soil removal should not be necessary if the pond is initially designed as a permanent disposal site. Correcting Williams' Table 3 for these factors yields a coal decomissioning cost about half that of nuclear. WNP-1 and WNP-3 decomissioning cost estimates are used as representative of nuclear decomissioning costs.

21. The environmental effluents for the representative plant, operating on gasified coal are as listed below (35F rating temperature, from BPA(86a) T.4-1):

	(lb/hr)	(T/MW/yr)	
SOx	63	0.61	
NOx	1200	11.65	*
CO	60	0.58	
Particulates (to atmosphere)	124	1.20	
Solid waste	64000	621.55	**
Water discharge	254508	2471.72	***

* 75 ppmv; can be reduced further by additional fuel gas moisture saturation.
** Slag, fly ash and sludge.
*** Treated waste water, blowdown, runoff.

R E F E R E N C E S

Battelle (82): Battelle, Pacific Northwest Laboratories. Development and Chararacterization of Electric Power Conservation and Supply Resource Planning Options. Prepared for the Northwest Power Planning Council. August, 1982.

BPA (86a): Bonneville Power Administration. Comparative Electric Generation Study: Coal Gasification Shell Gasification-based Phasing Study. Prepared by Fluor Technology, Inc. for the Bonneville Power Administration. November 1986.

BPA (86b): Bonneville Power Administration. Preconstruction Costs and Schedules for Comparative Electric Generation Study Coal-fired Power Plants. Prepared for Bonneville Power Administration by Kaiser Engineers Power Corporation. November, 1986.

Henriques(84): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

1 X 420 MW INTEGRATED COAL GASIFIER - COMBINED CYCLE POWER PLANT

January 1990 Base Year

HW: Handy-Whitman Index of Public Utility Construction Costs

NOAA(82): National Oceanic and Atmospheric Administration. Monthly Normals of Temperature, Precipitation and Heating and Cooling Degree Days: 1951-1980. 1982.

PNL(85): Pacific Northwest Laboratories. Electric Energy Supply Systems: Descriptions of Available Technologies (PNL-3277). Prepared for the U.S. Department of Energy. February 1985.

PNUCC(84): Pacific Northwest Utilities Conference Committee. Thermal Resources Data Base. October 1984. (Revised July 1987).

Williams(87): Williams, D.H. "Decommissioning Costs: Coal compared to Nuclear" Proceedings of the 1987 International Decommissioning Symposium. Pittsburgh, Pennsylvania. October, 1987.

197 MW ATMOSPERIC FLUIDIZED BED COAL-FIRED POWER PLANT

January 1990 Base Year

GENERAL PLANT DESCRIPTION

Type:		Overbed feed AFBC steam-electric, 2400 psig/1000F/1000F reheat	
Configuration:		One 197 MW unit	
Site:		Hermiston, Oregon	
Primary Fuel:		East Kootenay bituminous coal	
Heat Value (Btu/lb, HHV)		12000	
Delivery		Rail	
Inventory (days)		90	
Fixed Cost ($/kW/yr)		$0.00	
Variable Cost ($/MMBtu)		$1.50	
Alternate Fuel:		None	
Heat Value (Btu/lb, HHV)		n/a	
Delivery		n/a	
Inventory (days)		None	
Fixed Cost ($/kW/yr)		n/a	
Variable Cost ($/MMBtu)		n/a	
Environmental Controls:			
Heat Rejection		Mechanical draft cooling towers	EPRI(87)
Air Emission Controls	Particulates (0.03 lb/MMBtu input)	Baghouse	EPRI(87)
	SOx (90% removal)	Limestone injection	EPRI(87)
	NOx (0.6 lb/MMBtu input)	Combustion temperature control	EPRI(87)
Grid Interconnection:			
Configuration		230kV, double circuit	
Distance (mi)		10	

PLANT PERFORMANCE

Net Capacity and Heat Rate:	Capacity (MW)	Heat Rate (Btu/kWh)	
Maximum Sustainable Capacity	Not specified	Not specified	
Rated Capacity	197	9885	McGowin(88)
Minimum Sustainable Capacity	Not specified	Not specified	

Availability:		
Routine Inspection and Maintenance (days/year)	Not Specified	
Major Inspection and Overhaul (days/frequency)	Not Specified	
Average Planned Outage (days/year)	34	Note 1
Other Planned and Unplanned Outages (%)	10.0%	Note 1
Equivalent Annual Availability (%)	81.6%	Note 2
Service life (years)	30	Note 3

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197 MW ATMOSPERIC FLUIDIZED BED COAL-FIRED POWER PLANT

January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 4

Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	48	Henriques(84a)
Engineering, Equipment Procurement and Construction (months)	63	Note 5
Construction Cash Flow (% by year)	1/7/18/47/22/5	Note 6

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Land Option	SL1	Battelle(82) 15% of DC1	1/90	0.172	n/a	100	100	0.172	$1
Easements & ROW	SL2	BPA(86), T1-1	1/86	1.190	GNPD	112.4	128.8	1.364	$7
Owner's Costs	SL3	BPA(86) T1-1 (1.5% TPC)	1/90	5.560	n/a	100	100	5.560	$28
Permits & Licenses	SL4	BPA(86), T1-1	1/86	0.470	GNPD	112.4	128.8	0.539	$3
Geotechnical	SL5	BPA(86) T1-1 (0.12% TPC)	1/90	0.445	n/a	100	100	0.445	$2
EIS	SL6	BPA(86), T1-1	1/86	0.500	GNPD	112.4	128.8	0.573	$3
Total Siting & Lic.	TSL							8.652	$44

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 7	1/86	0.050	GNP	1.124	1.288	0.057	$0.29
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84b)	1/84	0.008	GNP	1.058	1.288	0.010	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84b)	1/84	0.028	GNP	1.058	1.288	0.034	$0.17
Land Option	OH4	Note 8	1/90	0.172	n/a	100	100	0.172	$0.87
Owner's Indirects	OH5	11% OH1-4, Henriques(84b)	1/90	0.030	n/a	100	100	0.030	$0.15
Total Annual Hold Costs	THC							0.302	$1.53

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197 MW ATMOSPERIC FLUIDIZED BED COAL-FIRED POWER PLANT

January 1990 Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 9)								
Land	DC1	500 Acres @ $2000/Acre	1/86	1.000	GNPD	112.4	128.8	1.146	$6
Struct. & Imp.	DC2	Note 10	1/83	34.440	HW7	234	276	40.622	$206
Steam Generation	DC3	Note 10	1/83	51.750	HW9	253	325	66.477	$337
Turb. Plant Equip.	DC4	Note 10	1/83	94.200	HW12	248	298	113.192	$575
Electrical Equip.	DC5	Note 10	1/83	17.190	HW13	282	323	19.689	$100
Misc. Equipment	DC6	Note 10	1/83	0.000	HW14	264	324	0.000	$0
Switchyard	DC8	Note 10	1/83	4.480	HW34	256	300	5.250	$27
Trans. Interconnect	DC9	Inc. in BC2	n/a	0.000	n/a	100	100	0.000	$0
Field Distributables	DC10	14% of DC1-DC8	1/90	34.332	n/a	100	100	34.332	$174
Total Direct Cost	TDC							280.708	$1,425
Indirect Costs:									
Indirect Const. Costs	IC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Engineering	IC2	Note 10, 8% of TDC	1/90	22.457	n/a	100	100	22.457	$114
Construction Management	IC3	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Contingency	IC4	Note 10, 15% of TDC+IC2	1/90	45.475	n/a	100	100	45.475	$231
Owner's Cost	IC5	PNUCC(84), 4% of TDC+IC2+IC4	1/90	13.946	n/a	100	100	13.946	$71
	IC6			0.000	n/a	100	100	0.000	$0
Total Indirect Cost	TIC							81.877	$416
Burdened Costs:									
Switchyard	BC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Trans. Interconnect	BC2	BPA, 10mi 230kV dbl ckt	1/87	3.710	HW33	252	297	4.373	$22
Spares	BC3	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Prepaid royalties	BC4	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
SE Impact Mitigation	BC5	1% of TPC, COTF	1/90	3.707	n/a	100	100	3.707	$19
	BC6			0.000	n/a	100	100	0.000	$0
Total Burdened Cost	TBC							8.079	$41
Total Plant Cost	TPC	TDC + TIC + TBC						370.664	$1,882

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197 MW ATMOSPHERIC FLUIDIZED BED COAL-FIRED POWER PLANT

January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		90	days	6.307	$32
Secondary Fuel Inventory	FI2		0	days	0.000	$0
Total Fuel Inventory Cost	TFI				6.307	$32
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	0.676	$3
Variable O&M	SU2	EPRI standard assumption	30	days	0.727	$4
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	0.491	$2
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	7.413	$38
Total Startup Cost:	TSU				9.307	$47
Total Preproduction Cost	TPPC	TFI + TSU			15.614	$79

CAPITAL COST SUMMARY

Siting & Licensing	8.652	$44
Plant	370.664	$1,882
Preproduction	15.614	$79
Total Overnight Capital Costs	394.930	$2,005

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 10	1/83	$31.75	GNPD	102	128.8	$40.09
Var. O&M (m/kWh)	OC2	Note 10	1/83	4.060	GNPD	102	128.8	5.1
Consumables (m/kWh)	OC3	Included in OC2	n/a	0.000	n/a	100	100	0.0
Byproduct Credit (m/kWh)	OC4	None	n/a	0.000	n/a	100	100	0.0
Cap. Rep. ($/kW/yr)	OC5	Included in OC1	n/a	$0.00	n/a	100	100	$0.00
Decomissioning	OC6	Note 11	1/90	$1.65	n/a	100	100	$1.65

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197 MW ATMOSPERIC FLUIDIZED BED COAL-FIRED POWER PLANT

January 1990 Base Year

NOTES

1. From EPRI(86) Exhibit B.5-10B, Technology 10.2.

2. Equivalent annual availability calculated from scheduled and unscheduled outages using EPRI methods. Rounded to 81 percent for modeling purposes.

3. 30-year service life is assumed because of relative immaturity of this coal technology in comparison to pulverized coal-fired power plants for which a 40-year service life is assumed.

4. Plant output may vary slightly by season because of ambient temperature. Planned outages can be scheduled at any time.

5. From BPA(87) Figure 5-26 (for one 110 MW AFBC coal-fired unit). Rounded to five years for modelling purposes.

6. From BPA(87) Para. 5.4.5 and Figure 5-27 (for one 110 MW AFBC coal-fired unit). First year payout rounded to 1%.

7. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

8. Annual land option hold cost is estimated to be 15% of total land cost, based on Washington Water Power experience at the Creston site.

9. Sales tax excluded from all cost estimates.

10. Costs are from letter of C.R. McGowin, Electric Power Research Institute to K. Watkins Bonneville Power Administration of March 23, 1988, containing cost breakdowns of Hermiston, Oregon cases of report EPRI CS-5296. Land cost component removed.

11. Information from Williams(87) suggests that coal plant decomissioning costs may be of the same order of magnitude as nuclear decomissioning costs. Williams' makes the case that coal plant decomissioning should cost, on a per kilowatt-hour basis, about the same as nuclear decomissioning. Review of Williams' adjustments to a coal plant decomissioning estimate (Table 3 of Williams(87)) indicates that several of Williams' adjustments may not be appropriate. Specifically: a greater contingency would likely apply to the nuclear decommissioning; unit removal costs for non-contaminated material may remain greater for nuclear because of routine surveillance for potential contamination; energy costs may be greater for nuclear because of large-scale electric cutting activities; and finally, ash pond soil removal should not be necessary if pond is initially designed as a permanent disposal site. Correcting Williams' table 3 for these factors yields a coal decomissioning cost about half that of nuclear. WNP-1 and WNP-3 decomissioning cost estimates are used as representative of nuclear decomissioning costs.

REFERENCES

Battelle (82): Battelle, Pacific Northwest Laboratories. Development and Chararacterization of Electric Power Conservation and Supply Resource Planning Options. Prepared for the Northwest Power Planning Council. August, 1982.

BPA (87): Bonneville Power Administration. Comparative Electric Generation Study: Coal-fired Power Plants. Prepared for Bonneville Power Administration by Kaiser Engineers Power Corporation. October, 1987.

BPA (86): Bonneville Power Administration. Preconstruction Costs and Schedules for Comparative Electric Generation Study Coal-fired Power Plants. Prepared for Bonneville Power Administration by Kaiser Engineers Power Corporation. November, 1986.

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197 MW ATMOSPERIC FLUIDIZED BED COAL-FIRED POWER PLANT

January 1990 Base Year

EPRI(87): Electric Power Research Institute. Evaluation of Alternative Steam Generator Designs for Atmospheric Fluidized-bed Combustion Plants (EPRI CS-5296). July 1987.

EPRI(86): Electric Power Research Institute. TAG - Technical Assessment Guide (EPRI P-4463-SR). December, 1986.

Henriques(84a): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated August 15, 1984, containing recommendations regarding coal-fired power plant siting and licensing assumptions.

Henriques(84b): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

HW: Handy-Whitman Index of Public Utility Construction Costs

McGowin(88): Letter from C.R. McGowin (EPRI) to Kevin Watkins (BPA) of March 23, 1988 regarding cost breakouts and additional background information concerning the Hermiston, Oregon cases in EPRI CS-5296.

Williams(87): Williams, D.H. "Decommissioning Costs: Coal compared to Nuclear" Proceedings of the 1987 International Decommissioning Symposium. Pittsburgh, Pennsylvania. October, 1987.

11-SEP-91

Northwest Power Planning Council Representative Power Plant

2 X 250 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

GENERAL PLANT DESCRIPTION

Type:	Pulverized firing steam-electric, 2400 psig/1000F/1000F reheat	
Configuration:	Two 250 MW units	
Site:	Hermiston, Oregon	
Primary Fuel:	East Kootenay bituminous coal	
Heat Value (Btu/lb, HHV)	12000	
Delivery	Rail	
Inventory (days)	90	
Fixed Cost ($/kW/yr)	$0.00	
Variable Cost ($/MMBtu)	$1.50	
Alternate Fuel:	None	
Heat Value (Btu/lb, HHV)	n/a	
Delivery	n/a	
Inventory (days)	None	
Fixed Cost ($/kW/yr)	n/a	
Variable Cost ($/MMBtu)	n/a	
Environmental Controls:		
Heat Rejection	Mechanical draft cooling towers	BPA(87)
Air Emission Controls (To meet NSPS):	Precipitators	BPA(87)
	Wet limestone scrubbers	BPA(87)
	Combustion temperature control	BPA(87)
Grid Interconnection:		
Configuration	230kV, double circuit	
Distance (mi)	10	

PLANT PERFORMANCE

Net Capacity and Heat Rate:	Capacity (MW)	Heat Rate (Btu/kWh)	
Maximum Sustainable Capacity	524	11145	Note 1
Rated Capacity	500	11005	Note 1
Minimum Sustainable Capacity	126	Not specified	Note 1

Availability:		
Routine Inspection and Maintenance (days/year)	30	Note 2
Major Inspection and Overhaul (days/frequency)	60 days @ five-year intervals	Note 2
Average Annual Maintenance and Outage (days/year)	36	Note 2
Other Planned and Unplanned Outages (%)	15.0%	Note 3
Equivalent Annual Availability (%)	76.6%	Note 4
Service life (years)	40	Note 5

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Northwest Power Planning Council Representative Power Plant
2 X 250 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 6

Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	48	Henriques(84a)
Engineering, Equipment Procurement and Construction (months)	60	Note 7
Construction Cash Flow (% by year)	3/16/31/34/16	Note 8

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Land Option	SL1	Battelle(82) 15% of DC1	1/90	0.284	n/a	100	100	0.284	$1
Easements & ROW	SL2	BPA(86), T1-1	1/86	1.190	GNPD	112.4	128.8	1.364	$3
Owner's Costs	SL3	BPA(86) T1-1 (1.5% TPC)	1/90	13.432	n/a	100	100	13.432	$27
Permits & Licenses	SL4	BPA(86), T1-1	1/86	0.470	GNPD	112.4	128.8	0.539	$1
Geotechnical	SL5	BPA(86) T1-1 (0.12% TPC)	1/90	1.075	n/a	100	100	1.075	$2
EIS	SL6	BPA(86), T1-1	1/86	0.500	GNPD	112.4	128.8	0.573	$1
Total Siting & Lic.	TSL							17.266	$35

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 9	1/86	0.050	GNP	1.124	1.288	0.057	$0.11
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84b)	1/84	0.020	GNP	1.058	1.288	0.024	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84b)	1/84	0.070	GNP	1.058	1.288	0.085	$0.17
Land Option	OH4	Note 10	1/90	0.284	n/a	100	100	0.284	$0.57
Owner's Indirects	OH5	11% OH1-4, Henriques(84b)	1/90	0.050	n/a	100	100	0.050	$0.10
Total Annual Hold Costs	THC							0.500	$1.00

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Northwest Power Planning Council Representative Power Plant
2 X 250 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 11)								
Land	DC1	BPA(87) (825 A @ 2000/A)	1/86	1.650	GNPD	112.4	128.8	1.891	$4
Struct. & Imp.	DC2	BPA(87)	1/86	48.850	HW7	250	276	53.930	$108
Steam Generation	DC3	BPA(87)	1/86	372.262	HW9	277	325	436.769	$874
Turb. Plant Equip.	DC4	BPA(87)	1/86	78.129	HW12	262	298	88.864	$178
Electrical Equip.	DC5	BPA(87)	1/86	23.683	HW13	271	323	28.227	$56
Miscellaneous Equip.	DC6	BPA(87)	1/86	0.548	HW14	285	324	0.623	$1
Switchyard	DC8	BPA	1/87	9.069	HW34	263	300	10.345	$21
Trans. Interconnect	DC9	Inc. in burdened costs	n/a	0.000	n/a	100	100	0.000	$0
	DC10		n/a	0.000	n/a	100	100	0.000	$0
Total Direct Cost	TDC							620.650	$1,241
Indirect Costs:									
Contractor O&P	IC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Engineering	IC2	BPA(87) (8% of TDC)	1/90	49.652	n/a	100	100	49.652	$99
Construction Management	IC3	BPA(87) (5% of TDC)	1/90	31.033	n/a	100	100	31.033	$62
Contingency	IC4	BPA(87) 20% of TDC+IC2+IC3	1/90	140.267	n/a	100	100	140.267	$281
Owner's Cost	IC5	PNUCC(84), 4% of TDC+IC2+IC3	1/90	33.664	n/a	100	100	33.664	$67
	IC6			0.000	n/a	100	100	0.000	$0
Total Indirect Cost	TIC							254.616	$509
Burdened Costs:									
Switchyard	BC1	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
Trans. Interconnect	BC2	BPA, 10mi 230kV dbl ckt	1/87	3.710	HW33	252	297	4.373	$9
Spares	BC3	BPA(87)	n/a	5.967	HW6	269	311	6.899	$14
Prepaid royalties	BC4	Included in direct costs.	n/a	0.000	n/a	100	100	0.000	$0
SE Impact Mitigation	BC5	1% of TPC, COTF	1/90	8.955	n/a	100	100	8.955	$18
	BC6		n/a	0.000	n/a	100	100	0.000	$0
Total Burdened Cost	TBC							20.226	$40
Total Plant Cost	TPC	TDC + TIC + TBC						895.492	$1,791

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Northwest Power Planning Council Representative Power Plant
2 X 250 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		90	days	17.821	$36
Secondary Fuel Inventory	FI2		0	days	0.000	$0
Total Fuel Inventory Cost	TFI				17.821	$36
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	1.537	$3
Variable O&M	SU2	EPRI standard assumption	30	days	1.077	$2
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	1.386	$3
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	17.910	$36
Total Startup Cost:	TSU				21.911	$44
Total Preproduction Cost	TPPC	TFI + TSU			39.732	$79

CAPITAL COST SUMMARY

Siting & Licensing	17.266	$35
Plant	895.492	$1,791
Preproduction	39.732	$79
Total Overnight Capital Costs	952.489	$1,905

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 12	1/90	35.760	GNPD	128.8	128.8	$35.76
Var. O&M (m/kWh)	OC2	Note 13	1/90	2.5	GNPD	128.8	128.8	2.5
Consumables (m/kWh)	OC3	Note 14	1/90	0.5	GNPD	128.8	128.8	0.5
Byproduct Credit (m/kWh)	OC4	None	n/a	0.000	n/a	100	100	0.0
Cap. Rep. ($/kW/yr)	OC5	Included in OC1	n/a	$0.00	n/a	100	100	$0.00
Decomissioning	OC6	Note 14	1/90	$1.65	n/a	100	100	$1.65

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Northwest Power Planning Council Representative Power Plant
2 X 250 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

NOTES

1. Capacity and heat rate from performance curves supplied by Bonneville, May 1, 1985.

2. Maintenance outage periods based on Northwest experience; see PNUCC (84).

3. Backcalculated from the equivalent annual availability and annual maintenance outage period. See NWPPC(86).

4. Equivalent annual availability based on North American Electric Reliability Council Generating Availability Data System records for subcritical coal-fired power plants. See NWPPC(86).

5. Design life of major components. Assumes a major refurbishment at year 20.

6. Plant output may vary slightly by season because of ambient temperature. Planned outages can be scheduled at any time.

7. From BPA(87) Figure 5-13 (to complete first unit; second unit would lag by 12 months).

8. S-Shaped cash flow, right-side skewed. For one unit. From Phung(78).

9. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

10. Annual land option hold cost is estimated to be 15% of total land cost, based on Washington Water Power experience at the Creston site.

11. Sales tax excluded from all cost estimates.

12. Annual O&M cost (excluding consumables) is labor plus maintenance materials and services. Labor costs are from BPA(87). Maintenance materials and services costs are calculated as 1.8 percent of total capital costs, excluding preproduction costs (An EPRI rule-of-thumb intended to include both routine annual maintenance and post-operational capital replacement costs). In accordance with EPRI practice, 70% of total O&M costs are taken as fixed; 30% as variable. 70% capacity factor used to calculate unit variable costs. 1986 dollar costs escalated to 1/88 using BPA "JEFOM" escalation series (per 1989 Supplement to 1986 power plan); and escalated from 1/88 to 1/90 using GNPD.

	(MM$/yr) (1/86)	(MM$/yr) (1/90)		
Labor (BPA(87)), Table 5-9	6.919	9.113		
Maintenance materials and services		16.430	(1.8 %	Overnight Capital Costs)
Total		25.543		
Fixed O&M costs (70% of total)		17.880	35.76	$/kW/yr
Variable O&M costs (30% of total)		7.663	2.5	mills/kWh

13. Consumables include costs of materials and chemicals, utilities and sludge and ash disposal from BPA(87), Table 5-9. 70% capacity factor assumed. Escalated as described in note 12.

	(MM$/yr) (1/86)	(MM$/yr) (1/90)		
Materials and chemicals	0.866	1.141		
Utilities	0.310	0.408	(Note 14)	
Sludge and ash disposal	0.337	0.444		
Total		1.513	0.5	mills/kWh

11-SEP-91 Northwest Power Planning Council Representative Power Plant
2 X 250 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

14. Estimated raw water usage in BPA(87) Table 5-9 is apparently in error. Based on raw water pumping capacity and comparison with the 2x603MW case, the raw water consumption should be half of that shown in Table 5-9.

15. Information from Williams(87) suggests that coal plant decomissioning costs may be of the same order of magnitude as nuclear decomissioning costs. Williams' makes the case that coal plant decomissioning should cost, on a per kilowatt-hour basis, about the same as nuclear decomissioning. Review of Williams' adjustments to a coal plant decomissioning estimate (Table 3 of Williams(87)) indicates that several of Williams' adjustments may not be appropriate. Specifically: a greater contingency would likely apply to the nuclear decommissioning; unit removal costs for non-contaminated material may remain greater for nuclear because of routine surveillance for potential contamination; energy costs may be greater for nuclear because of large-scale electric cutting activities; and finally, ash pond soil removal should not be necessary if pond is initially designed as a permanent disposal site. Correcting Williams' table 3 for these factors yields a coal decomissioning cost about half that of nuclear. WNP-1 and WNP-3 decomissioning cost estimates are used as representative of nuclear decomissioning costs.

REFERENCES

Battelle (82): Battelle, Pacific Northwest Laboratories. Development and Chararacterization of Electric Power Conservation and Supply Resource Planning Options. Prepared for the Northwest Power Planning Council. August, 1982.

BPA (87): Bonneville Power Administration. Comparative Electric Generation Study: Coal-fired Power Plants. Prepared for Bonneville Power Administration by Kaiser Engineers Power Corporation. October, 1987.

BPA (86): Bonneville Power Administration. Preconstruction Costs and Schedules for Comparative Electric Generation Study Coal-fired Power Plants. Prepared for Bonneville Power Administration by Kaiser Engineers Power Corporation. November, 1986.

Henriques(84a): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated August 15, 1984, containing recommendations regarding coal-fired power plant siting and licensing assumptions.

Henriques(84b): Letter from R. E. Henriques, Washington Water Power Company to J.C. King, Northwest Power Planning Council, dated July 17, 1984.

HW: Handy-Whitman Index of Public Utility Construction Costs

NWPPC(86): Northwest Power Planning Council. 1986 Northwest Conservation and Electric Power Plan. January 1986.

PNUCC(84): Pacific Northwest Utilities Conference Committee. Thermal Resources Data Base. October 1984. (Revised July 1987).

Williams(87): Williams, D.H. "Decommissioning Costs: Coal compared to Nuclear" Proceedings of the 1987 International Decommissioning Symposium. Pittsburgh, Pennsylvania. October, 1987.

Northwest Power Planning Council Representative Power Plant

2 X 6Ø3 MW PULVERIZED COAL-FIRED POWER PLANT

January 199Ø Base Year

GENERAL PLANT DESCRIPTION

Type:	Pulverized firing steam-electric, 24ØØ psig/1ØØØF/1ØØØF reheat	
Configuration:	Two 6Ø3 MW units	
Site:	Hermiston, Oregon	
Primary Fuel:	East Kootenay bituminous coal	
Heat Value (Btu/lb, HHV)	12ØØØ	
Delivery	Rail	
Inventory (days)	9Ø	
Fixed Cost ($/kW/yr)	$Ø.ØØ	
Variable Cost ($/MMBtu)	$1.5Ø	
Alternate Fuel:	None	
Heat Value (Btu/lb, HHV)	n/a	
Delivery	n/a	
Inventory (days)	None	
Fixed Cost ($/kW/yr)	n/a	
Variable Cost ($/MMBtu)	n/a	
Environmental Controls:		
Heat Rejection	Mechanical draft cooling towers	BPA(87)
Air Emission Controls (to meet NSPS):	Precipitators	BPA(87)
	Wet limestone scrubbers	BPA(87)
	Combustion temperature control	BPA(87)
Grid Interconnection:		
Configuration	5ØØkV, double circuit	
Distance (mi)	1Ø	

PLANT PERFORMANCE

Net Capacity and Heat Rate:	Capacity (MW)	Heat Rate (Btu/kWh)	
Maximum Sustainable Capacity	1266	1Ø97Ø	Note 1
Rated Capacity	12Ø6	1Ø856	Note 1
Minimum Sustainable Capacity	3Ø2	Not specified	Note 1

Availability:		
Routine Inspection and Maintenance (days/year)	3Ø	Note 2
Major Inspection and Overhaul (days/frequency)	6Ø days @ five-year intervals	Note 2
Average Annual Maintenance and Outage (days/year)	36	Note 2
Other Planned and Unplanned Outages (%)	17.Ø%	Note 3
Equivalent Annual Availability (%)	74.8%	Note 4
Service life (years)	4Ø	Note 5

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Northwest Power Planning Council Representative Power Plant
2 X 603 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

PLANT PERFORMANCE (CONTINUED)

Energy production potential by month (Percent of annual total): Note 6

Jan	8.3%
Feb	8.3%
Mar	8.3%
Apr	8.3%
May	8.3%
Jun	8.3%
Jul	8.3%
Aug	8.3%
Sep	8.3%
Oct	8.3%
Nov	8.3%
Dec	8.3%

DEVELOPMENT SCHEDULES

Siting and Licensing (months)	48	Henriques(84a)
Engineering, Equipment Procurement and Construction (months)	72	Note 7
Construction Cash Flow (% by year)	2/10/21/29/27/11	Note 8

SITING & LICENSING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Land Option	SL1	Battelle(82) 15% of DC1	1/90	0.579	n/a	100	100	0.579	$0
Easements & ROW	SL2	BPA(86), T1-1	1/86	1.190	GNPD	112.4	128.8	1.364	$1
Owner's Costs	SL3	BPA(86) T1-1 (1.5% TPC)	1/90	23.497	n/a	100	100	23.497	$19
Permits & Licenses	SL4	BPA(86), T1-1	1/86	0.470	GNPD	112.4	128.8	0.539	$0
Geotechnical	SL5	BPA(86) T1-1 (0.12% TPC)	1/90	1.880	n/a	100	100	1.880	$2
EIS	SL6	BPA(86), T1-1	1/86	0.500	GNPD	112.4	128.8	0.573	$0
Total Siting & Lic.	TSL							28.431	$24

OPTION HOLD COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Project Management	OH1	Note 9	1/86	0.050	GNP	1.124	1.288	0.057	$0.05
Siting Council Fees	OH2	$0.04/kW/yr, Henriques(84b)	1/84	0.048	GNP	1.058	1.288	0.059	$0.05
Environmental Baseline	OH3	$0.14/kW/yr, Henriques(84b)	1/84	0.169	GNP	1.058	1.288	0.206	$0.17
Land Option	OH4	Note 10	1/90	0.579	n/a	100	100	0.579	$0.48
Owner's Indirects	OH5	11% OH1-4, Henriques(84b)	1/90	0.099	n/a	100	100	0.099	$0.08
Total Annual Hold Costs	THC							0.999	$0.83

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Northwest Power Planning Council Representative Power Plant
2 X 6Ø3 MW PULVERIZED COAL-FIRED POWER PLANT

January 199Ø Base Year

PLANT COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate (MM$)	Escl. Index	Price Yr Index	Base Yr Index	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Direct Costs:	(Note 11)								
Land	DC1	BPA(87) (168Ø A @ 2ØØØ/A)	1/86	3.366	GNPD	112.4	128.8	3.857	$3
Struct. & Imp.	DC2	BPA(87)	1/86	82.6Ø7	HW7	25Ø	276	91.198	$76
Steam Generation	DC3	BPA(87)	1/86	654.312	HW9	277	325	767.695	$637
Turb. Plant Equip.	DC4	BPA(87)	1/86	155.4Ø9	HW12	262	298	176.763	$147
Electrical Equip.	DC5	BPA(87)	1/86	27.373	HW13	271	323	32.625	$27
Miscellaneous Equip.	DC6	BPA(87)	1/86	Ø.899	HW14	285	324	1.Ø22	$1
Switchyard	DC8	BPA	1/87	9.9ØØ	HW34	263	3ØØ	11.293	$9
Trans. Interconnect	DC9	Inc. in burdened costs	n/a	Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
	DC1Ø		n/a	Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
Total Direct Cost	TDC							1Ø84.453	$899
Indirect Costs:									
Contractor O&P	IC1	Included in direct costs.	n/a	Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
Engineering	IC2	BPA(87) (8% of TDC)	1/9Ø	86.756	n/a	1ØØ	1ØØ	86.756	$72
Construction Management	IC3	BPA(87) (5% of TDC)	1/9Ø	54.223	n/a	1ØØ	1ØØ	54.223	$45
Contingency	IC4	BPA(87) 2Ø% of TDC+IC2+IC3	1/9Ø	245.Ø86	n/a	1ØØ	1ØØ	245.Ø86	$2Ø3
Owner's Cost	IC5	PNUCC(84), 4% of TDC+IC2+IC3	1/9Ø	58.821	n/a	1ØØ	1ØØ	58.821	$49
	IC6			Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
Total Indirect Cost	TIC							444.886	$369
Burdened Costs:									
Switchyard	BC1	Included in direct costs.	n/a	Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
Trans. Interconnect	BC2	BPA, 1Ømi 5ØØkV dbl ckt	1/87	8.5ØØ	HW33	252	297	1Ø.Ø18	$8
Spares	BC3	BPA(87)	n/a	9.913	HW6	269	311	11.461	$1Ø
Prepaid royalties	BC4	Included in direct costs.	n/a	Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
SE Impact Mitigation	BC5	1% of TPC, COTF	1/9Ø	15.665	n/a	1ØØ	1ØØ	15.665	$13
	BC6		n/a	Ø.ØØØ	n/a	1ØØ	1ØØ	Ø.ØØØ	$Ø
Total Burdened Cost	TBC							37.143	$31
Total Plant Cost	TPC	TDC + TIC + TBC						1566.482	$1,299

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Northwest Power Planning Council Representative Power Plant
2 X 603 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

PREPRODUCTION CAPITAL COSTS

Account	Acct.	Source	Qty.	Units	Base Yr. Estimate (MM$)	Base Yr. Estimate ($/kW)
Fuel inventory:						
Primary Fuel Inventory	FI1		90	days	42.403	$35
Secondary Fuel Inventory	FI2		0	days	0.000	$0
Total Fuel Inventory Cost	TFI				42.403	$35
Startup Costs:						
Fixed O&M	SU1	EPRI standard assumption	30	days	2.489	$2
Variable O&M	SU2	EPRI standard assumption	30	days	1.806	$1
Fixed Fuel	SU1	EPRI standard assumption	7	days	0.000	$0
Variable Fuel	SU3	EPRI standard assumption	7	days	3.298	$3
Equip. Modification	SU4	EPRI standard assumption	2.0%	percent total plant cost	31.330	$26
Total Startup Cost:	TSU				38.923	$32
Total Preproduction Cost	TPPC	TFI + TSU			81.326	$67

CAPITAL COST SUMMARY

Siting & Licensing	28.431	$24
Plant	1566.482	$1,299
Preproduction	81.326	$67
Total Overnight Capital Costs	1676.239	$1,390

OPERATING COSTS

Account	Acct.	Source	Price Year	Price Yr Estimate	Escl. Index	Price Yr Index	Base Yr Index	Base Yr Estimate
Fixed O&M ($/kW/yr)	OC1	Note 12	1/90	23.46	GNPD	128.8	128.8	$23.46
Var. O&M (m/kWh)	OC2	Note 13	1/90	1.6	GNPD	128.8	128.8	1.6
Consumables (m/kWh)	OC3	Note 14	1/90	0.4	GNPD	128.8	128.8	0.4
Byproduct Credit (m/kWh)	OC4	None	n/a	0.0	n/a	100	100	0.0
Cap. Rep. ($/kW/yr)	OC5	Included in OC1	n/a	$0.00	n/a	100	100	$0.00
Decomissioning	OC6	Note 15	1/90	$1.65	n/a	100	100	$1.65

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Northwest Power Planning Council Representative Power Plant

2 X 603 MW PULVERIZED COAL-FIRED POWER PLANT

January 1990 Base Year

NOTES

1. Capacity and heat rate from performance curves supplied by Bonneville, May 1, 1985.

2. Maintenance outage periods based on Northwest experience; see PNUCC (84).

3. Backcalculated from the equivalent annual availability and annual maintenance outage period. See NWPPC(86).

4. Equivalent annual availability based on North American Electric Reliability Council Generating Availability Data System records for subcritical coal-fired power plants. See NWPPC(86).

5. Design life of major components. Assumes a major refurbishment at year 20.

6. Plant output may vary slightly by season because of ambient temperature. Planned outages can be scheduled at any time.

7. Based on discussions of the Council's Coal Options Task Force, consistent with the schedule proposed for Creston. (to complete first unit; second unit would lag by 12 months).

8. S-Shaped cash flow, right-side skewed. For one unit. From Phung(78).

9. Annual cost of one engineering staff, as estimated by the Northwest Power Planning Council Coal Options Task Force.

10. Annual land option hold cost is estimated to be 15% of total land cost, based on Washington Water Power experience at the Creston site.

11. Sales tax excluded from all cost estimates.

12. Annual O&M cost (excluding consumables) is labor plus maintenance materials and services. Labor costs are from BPA(87). Maintenance materials and services costs are calculated as 1.8 percent of total capital costs, excluding preproduction costs (An EPRI rule-of-thumb intended to include both routine annual maintenance and post-operational capital replacement costs). In accordance with EPRI practice, 70% of total O&M costs are taken as fixed; 30% as variable. 70% capacity factor used to calculate unit variable costs. 1986 dollar costs escalated to 1/88 using BPA "JEFOM" escalation series (per 1989 Supplement to 1986 power plan); and escalated from 1/88 to 1/90 using GNPD.

	(MM$/yr) (1/86)	(MM$/yr) (1/90)		
Labor (BPA(87)), Table 5-3	8.891	11.711		
Maintenance materials and services		28.708	(1.8 %	Overnight Capital Costs)
Total		40.419		
Fixed O&M costs (70% of total)		28.293	23.46	$/kW/yr
Variable O&M costs (30% of total)		12.126	1.6	mills/kWh

13. Consumables include costs of materials and chemicals, utilities and sludge and ash disposal from BPA(87), Table 5-3. 70% capacity factor assumed. Escalated as described in note 12.

	(MM$/yr) (1/86)	(MM$/yr) (1/90)		
Materials and chemicals	1.894	2.495		
Utilities	0.519	0.684		
Sludge and ash disposal	0.844	1.112		
Total		3.257	0.4	mills/kWh

11-SEP-91 Northwest Power Planning Council Representative Power Plant

2 X 6Ø3 MW PULVERIZED COAL-FIRED POWER PLANT

January 199Ø Base Year

14. Information from Williams(87) suggests that coal plant decomissioning costs may be of the same order of magnitude as nuclear decomissioning costs. Williams' makes the case that coal plant decomissioning should cost, on a per kilowatt-hour basis, about the same as nuclear decomissioning. Review of Williams' adjustments to a coal plant decomissioning estimate (Table 3 of Williams(87)) indicates that several of Williams' adjustments may not be appropriate. Specifically: a greater contingency would likely apply to the nuclear decommissioning; unit removal costs for non-contaminated material may remain greater for nuclear because of routine surveillance for potential contamination; energy costs may be greater for nuclear because of large-scale electric cutting activities; and finally, ash pond soil removal should not be necessary if pond is initially designed as a permanent disposal site. Correcting Williams' table 3 for these factors yields a coal decomissioning cost about half that of nuclear. WNP-1 and WNP-3 decomissioning cost estimates are used as representative of nuclear decomissioning costs.

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NWPPC(86): Northwest Power Planning Council. 1986 Northwest Conservation and Electric Power Plan. January 1986.

PNUCC(84): Pacific Northwest Utilities Conference Committee. Thermal Resources Data Base. October 1984. (Revised July 1987).

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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]

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)
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

Table 8-B-1
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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

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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)
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

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)
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

Table 8-B-1
Potentially Developable Hydropower Sites[a]

NOTES:

[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

The Council's Environmental Strategy

The Northwest Power Act identifies several distinctly different ways that environmental effects are to be considered by the Council, as it develops its power plan, and by the administrator of the Bonneville Power Administration when he 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 would need to consider environmental effects in the planning stage, before specific information related to resource 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 impacts 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 regulations 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 used throughout the power plan. In some cases, for example in its choice to focus on coal-gasification in lieu of pulverized coal plants, the Council has gone beyond present and anticipated regulatory action.

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. In this plan, the Council has indicated its intent to develop criteria for the siting, licensing and operation of other resources in its portfolio.

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 activities in Volume I, Chapter 1, and the possible consequences of those actions. The sensitivity analyses are described more fully in the resource portfolio chapter (Volume II, Chapter 10).

4. 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 of each resource.

5. The Council allowed an additional 2 cents per kilowatt-hour of credit for conservation, because of its

many non-quantified benefits, including its environmental advantage over other resources. In addition, it focused much of the near-term activity toward confirmation of renewable resources. This activity should speed the entry of those resources into the regional mix of generating plants.

6. The Council elected to constrain its reliance on certain resources. Part of the reason for these limitations 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, the Council felt it was prudent to anticipate some limitations on the desirability of fossil-fuel combustion resources. Thus, the initial reliance is on conservation and natural gas, with conversion from natural gas to coal gasification remaining as an option subject to conditions of the future.

In implementing the strategy described above, the Council effectively weighed the costs and benefits of environmental mitigation and explored alternative actions to incorporate environmental considerations. None of these choices led to establishing an explicit dollar value for externalities. However, the actions did lead to a more 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 Volume II, Chapter 1. In addition, the Council will continue to work with Bonneville, utilities and states to enhance methodologies for quantifying and incorporating environmental costs.

While the discussion above describes the strategy for environmental consideration during the planning process, at the time of resource acquisition, Bonneville 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 contains specific steps to quantify costs and benefits, but recognizes that within the specific steps, quantification of environmental effects becomes a judgment call. 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. 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 "case studies" have been some of the most extensive efforts in the nation to quantify the environmental costs of resources.

The remainder of this chapter reviews historical experiences in the Northwest and elsewhere in estimating environmental costs. It then discusses the effects of key pollutants associated with many resources. Pollutants associated with specific plants and their known effects are identified, and their effects on the environment are spelled out. Finally, the section summarizes 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, consistent with assumptions in Volume II, Chapter 8, are installed and operating satisfactorily.

Experiences in Addressing Environmental Costs

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 part on where the resources were to be developed and the ambient environmental conditions.[2]

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.

2. Requirements are 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 must 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.

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 resource externalities is government regulation, to either control the externalities or to establish a market for the right to impose the external costs. 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. 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.

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 estimate a dollar value for externalities during its planning process. Instead, it considers the relative environmental degradation from each of its planned resources subjectively. In this plan, the Council's subjective decisions to protect the environment include a 2 cent per kilowatt-hour credit for conservation, limited reliance on coal-fired plants, and an aggressive agenda to prove the reliability of renewable resources in the region. Earlier, 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 Bonneville administrator that he maintain the 10-percent cost advantage for conservation, in part, because conservation is environmentally benign compared to most other resources.

The Council also has made environmental decisions based on the need to protect fish and wildlife. These decisions were made without specific dollar estimates of the different 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. In the future, the Council will 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 1987 decision to maintain an environmental benefit for conservation. Citing the Council's actions, Wisconsin adopted a 15-percent credit for conservation resources because of their environmental benefits. New England is considering going well beyond the 15-percent benefit. New York 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 many of these efforts have attached a single benefit to conservation relative to all other resources, without differentiation, 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.

Recently, there have been a number of attempts to establish more resource-specific estimates of environmental damages. Perhaps the most comprehensive study was by the Pace University Center for Environmental Legal Studies, documented in *Environmental Costs of Electricity*. Bonneville also has conducted updated estimates of externalities that it is using to assess resources in its competitive acquisition process. Bonneville used the Council's methodology in its efforts. This chapter presents a comprehensive description of the amount of pollutants emitted by generating plants under consideration and discusses their known and hypothesized effects on the environment. It stops short of ranking resources by their externalities or any attempt to quantify them.

3. In fact, payment is not tied to damages imposed. It is determined by willingness to pay for the right to pollute.

The Council maintains that quantification of environmental effects is more appropriate as specific resources are being acquired. At that point, characteristics of individual power plants and their location relative to affected fauna and flora are known. In addition, the Council recognizes that clear policy directions are needed to ensure that "dirty" plants are not built. Without clear policy, these plants could be built even if environmental effects have been quantified if base costs are low enough to offset estimated externalities. As a result, the Council has directed its staff to work with Bonneville, utilities, state regulatory commissions, and other state government agencies as they seek to quantify environmental effects in their own forums. In its plan, the Council has focused on acquisition of environmentally responsible resources in the near-term and has delayed reliance on thermal plants that many consider to be risky environmentally.

In the past, many utilities voiced concern that adding the costs of environmental consequences to resource estimates could greatly increase the potential cost of those resources, thus increasing the companies' avoided costs. This could have the effect under the Public Utility Regulatory Policies Act (PURPA) of compelling utilities to purchase higher priced resources, including more costly conservation. Many utilities now appear to be willing to risk such an event if they are able to earn returns on those resource expenditures.

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 cause greater environmental harm. 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 other activities we choose to do every day. It is critical, to the extent possible, that we keep these issues in perspective. 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.

In this chapter, to the extent practicable, each of the major environmental pollutants or other electric energy-related disruptions to the environment are physically quantified, and the known damages or benefits associated with each are described. This information enables 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 decides which activities to pursue. In this and all preceding plans, the Council has decided to pursue aggressively the more environmentally responsible resources, such as conservation, and to defer coal and nuclear plants until major uncertainties regarding their development are resolved.

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 the source. Later, in the discussion of each specific generating resource, the physical quantity of all major pollutants emitted from each will be presented. This will allow consideration first of the effect 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 related to generating power in the left 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 column of the table and three review categories along the top of the columns. The three categories are: 1) pollutants addressed in the National Environmental Policy Act; 2) "criteria pollutants" regulated by the Clean Air Act; and 3) pollutants' 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. Pollutants with entries ("X") under the NEPA and the criteria pollutants categories are addressed by the Environmental Protection Agency in one way or another and also are 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 pare an exhaustive list to concentrate on those major pollutants or actions that are expected to have the greatest effect on the environment.

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 stages of the fuel cycle. This is due in part to the vast amounts that can be emitted at this stage, in part because of the damaging properties of the pollutants, and in part because airborne emissions from plants can affect the environment thousands of miles away, as well as at and around the plant site. 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 (NOx); 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 many scientists believe could cause the planet to undergo dramatic climate changes. Thus, it is included in this chapter as an emission of major concern.

The rest of this chapter describes the effects of pollutants indicated in Table 9-1 for each generating resource and distills this information to a usable summary of environmental impacts. 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
Environmental Pollutants and Their Effects[a]

	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
▪ 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[b]			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

Table 9-1 (cont.)
Environmental Pollutants and Their Effects

	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
▪ Toxic Substances/ Trace Elements			X	X	X	X	X		X
▪ Organics				X	X	X	X		X
▪ Consumption				X	X	X	X		X
▪ Carbonates									
▪ Ammonia			X						
▪ Chlorine			X	X	X	X	X		
Land									
▪ Use/Requirements					X	X	?	X	X
▪ Solid Waste[c]			X	?	?	?	?		
▪ Other									
Noise		X		X				X	
Radioactive Emissions			X	X	X	X	X		X
Community Infrastructure					X			X	

[a] Except for carbon dioxide, adapted from Nero and Associates, Inc. *Working Paper, Study Module VI, Quantification of Environmental Costs and Benefits. Task 1: Taxonomy of Impacts.* Prepared for the Northwest Power Planning Council, April 1982.

[b] These impacts assume that increased carbon dioxide will cause global warming.

[c] Including radioactive waste.

Table 9–2
Applicability of Selection Criteria to Environmental Impacts

	Criteria NEPA Requirements[a]	Criteria Pollutant[a, b]	Applicability to Multiple Resources
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		
▪ Methane	X		
▪ Hydrogen Sulfide	X		
▪ Radioactive Gas (tritium, iodine, noble gases)	X	X[c]	
▪ Ammonia	X		
▪ Argon	X		
▪ Hydrogen	X		
▪ Carbon Dioxide	X		
Water			
▪ Biological Oxygen Demand	X	X	X
▪ Chemical Oxygen Demand	X	X	X
▪ Suspended Solids	X	X	X
▪ Dissolved Solids	X	X	X
▪ Toxic Substances/Trace Elements	X	X	X
▪ Organics	X	X	X
▪ Consumption/Requirements	X	X	X
▪ Carbonates	X	X	X
▪ Ammonia	X	X	X
▪ Chlorine	X	X	
▪ Phosphates			
Land			
▪ Use/Requirements	X		X
▪ Solid Waste	X	X[c]	X
▪ Other			

Table 9–2 (cont.)
Applicability of Selection Criteria to Environmental Impacts

	Criteria NEPA Requirements[a]	Criteria Pollutant[a, b]	Applicability to Multiple Resources
Noise			X
Radioactive Emissions	X	X	
Community Infrastructure	X		X

[a] Criteria pollutant applicability is from Nero and Associates, Inc., 1982. The effect of later amendments or administrative actions related to the Clean Air Act, Clean Water Act or other federal pollution control legislation are not shown. The information regarding control of radioactive materials from nuclear power plants is based on the discussion of nuclear power plant environmental effects that appears in this chapter.

[b] Pollutants for which federal standards are established.

[c] Federal standards applying to radioactive material releases from nuclear power plants.

Description of Major Pollutants Associated with Multiple Resource Options

This section describes the major airborne effluents released from power plants along with appropriate mitigation technologies for each.[5] Tables 9-1 and 9-2 show a number of important pollutants typically associated with combustion-based power plants. They are: 1) particulates, 2) sulfur dioxide, 3) oxides of nitrogen, 4) carbon monoxide, 5) carbon dioxide and 6) methane. These effluents 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 collectively 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 be carriers of harmful pollutants that can damage the lining of the lungs. Most of the respirable suspended particles are formed by combustion of fuels in automobiles, industrial processes and in power plants.

Particulates also affect visibility. Loss of visibility, particularly where the views are important, has been shown to be costly to the public in a number of economic studies.

Mitigation

With conventional coal combustion, the composition of the particulates and potential 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, breeches and chimney bases.

Electrostatic precipitators are the most common high-efficiency control devices used on pulverized coal plants. 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 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.

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 in 1990; from the Council's 1986 Power Plan; and work done for the Council by Battelle as the Council developed its first power plan.

Even with the 99 percent effective controls used on modern coal plants, the amount of particulates released into the atmosphere is about 1.75 tons per megawatt-year, or about 450 tons per year for a large coal plant.

Particulate removal in coal gasification plants is accomplished by subjecting the product gas to a series of wet and dry particulate removal operations. In the representative coal gasification combined-cycle power plant used as the basis for coal resource cost analysis in this plan, the product gas is cooled as it is discharged from the gasifier then passed through a dry cyclone that removes the majority of entrained solids. The gas is then washed in a scrubber and passed through a second cyclone which removes more solids and water droplets. The gas receives a final washing in a tray scrubber. The resulting particulate releases (0.2 tons per megawatt-year) from the gas turbine are no greater than if the turbine operated on natural gas. (Additional particulates, however, would be released from the coal feed and ash handling systems).

For fuel oil combustion, particulate production depends 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.

Because of the gaseous fuel, particulate release from natural gas-fired combustion turbines is very low. Particulate releases from the representative simple-cycle combustion turbines used in this plan are estimated to be about 0.3 tons per megawatt-year. Because of greater efficiency, the Council's representative natural gas-fired combined-cycle plants could be expected to release about 0.2 tons per megawatt-year.

Particulates are the major emission concern from wood-fired boilers. 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 commonly used in many larger boilers to improve fuel efficiency.

In addition, wood-fired boiler emissions are influenced by boiler size, age, load factors and wood species. 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 number of 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 are known to 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, because sulfur oxide emissions are proportional to the sulfur content of the coal. Most commercially available Western coals have a low sulfur content.

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.

Flue gas desulfurization techniques are used to further reduce sulfur oxides formed during combustion. Wet lime scrubbing or limestone scrubbing are the most common mitigation 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]

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. Sulfur removal efficiencies exceeding 99 percent are possible with coal gasification plants. The sulfur is converted to pure sulfur and marketed as a byproduct. Because waste sludge is not produced, the solid waste produced by coal gasification plants is much less than for pulverized or fluidized bed designs.

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.

Most municipal solid waste systems also use scrubbing systems.

Oxides of Nitrogen

End products from fuel combustion include several oxides of nitrogen. These are formed through the oxidation of nitrogen in the fuel and in the combustion air. 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 air is offset by the increasing nitrogen oxide levels due to the increased flame temperature (nitrogen oxide levels increase as a function of the combustion temperatures). Excess combustion air can be limited by staged combustion. This involves a two-stage fuel burn. The first stage uses a minimum amount of oxygen, and the second stage introduces more oxygen to yield a complete burn.

A second approach to controlling NOx formation in coal furnaces is to lower flame temperatures. This can be accomplished by use of "dual-register burners" that prolong combustion and thereby lower combustion temperatures. In fluidized-bed plants, the formation of oxides is slowed, because the combustion temperature is lower than for conventional furnaces.

Other nitrogen oxide reduction techniques include flue-gas recirculation, load reduction, and steam or water injection. However, these techniques are not very effective with 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.

Nitrogen oxides formation is significantly reduced in medium Btu coal gasification plants. These plants (including the representative coal gasification plant used as the basis for the cost analysis of this plant) use an oxygen feed

7. The higher the removal rate, the higher are 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 also can be used as fluids to absorb sulfur dioxide.

so that no nitrogen is introduced to the gasification process through combustion air. Some oxides of nitrogen are formed from the nitrogen in the coal, and additional nitrogen oxides are formed during the combustion of the product gas in the combustion turbine. Nitrogen formation in the combustion turbine is controlled by saturating the product gas with moisture and by water injection. These techniques reduce turbine combustion temperatures, inhibiting formation of oxides of nitrogen. Additional nitrogen oxide control can be obtained by catalytic reduction of nitrogen oxides in the combustion turbine exhaust. (Catalytic reduction is not included in the Council's representative coal-gasification power plant, but is compatible with this plant design, at additional cost.)

Similar combustion modifications are used for boilers burning fuel oil, natural gas, biomass residues and municipal solid waste. 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, 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. However, utilities in the Los Angeles area are planning to retrofit their natural gas-fired boilers with selected catalytic reduction, in order to meet the requirements of the South Coast Air Quality Management District. The expected cost of the retrofit is about $1,200 per kilowatt of capacity. Note that this cost is much greater than the estimated cost of installing selective catalytic reduction on new combustion turbine power plants.

Nitrogen oxide control on natural gas combustion turbine power plants, both simple and combined-cycle, is accomplished by steam or water injection, "low-NOx" combustor designs and by selective catalytic reduction. Low-NOx combustors and steam or water injection control excess air and combustion temperatures, and can achieve NOx releases to about 40-50 parts per million, and possibly as low as 25 parts-per-million. Further reduction will likely require use of catalytic converters. NOx release levels as low as 9 parts-per-million are achievable with selective catalytic reduction (SCR) technology. SCR technology on a combined-cycle plant is estimated to cost from $25 to $32 per kilowatt capacity. Operating costs are estimated to be $26 to $40 per kilowatt per year.

The representative simple and combined-cycle combustion turbines used in this plan include low-NOx combustors and water injection. SCR is not included, but is compatible with the representative designs.

Carbon Monoxide

Carbon monoxide is a colorless, odorless gas. It interferes with the body's ability to deliver oxygen. 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 impaired growth and mental development.

Mitigation

Carbon monoxide is generally emitted in quite small amounts from power 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. Therefore, 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, special control measures to limit carbon monoxide are not typically applied.

Carbon Dioxide

The combustion of any fossil fuel produces carbon dioxide. Carbon dioxide is the largest by volume of the "greenhouse gases," the gases believed to cause global warming. Carbon dioxide and the other greenhouse gasses let the sun's radiation through, but trap the heat, keeping it from escaping the earth's surface. The greenhouse effect of the atmosphere is not 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 may cause the earth's temperature to increase at unprecedented rates, with potentially disastrous results. The feared results include rising sea levels; climate changes to rapid too allow plants and animals time to adjust to the new environmental conditions; and dramatic changes in local climates around the world.[9] One of the

9. Interested readers should review the papers presented during a workshop held by the Council on the greenhouse effect and its result, global warming. The workshop included presentations to the Council by experts on the subject of global warming. It was held in Olympia, Washington, on February 9, 1989. Call the Council's public affairs division for copies.

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

The amount of carbon dioxide released from fuel combustion is a function of the fuel's carbon-to-hydrogen ratio (the principal combustible elements in fossil and biomass fuels). Coal contains the greatest proportion of carbon, and fuel oils and natural gas proportionally less. Variations in carbon dioxide emissions from combustion of a given carbon-containing fuel depend almost entirely on the overall efficiency of the process. More efficient technologies such as combined-cycle plants produce less CO_2 per unit of energy produced than less efficient technologies using the same fuel.

Beyond fuel selection and efficiency improvements, there is no good way to mitigate the release of carbon dioxide from the combustion of fossil fuels. Preliminary studies have been conducted to determine the cost of recovering carbon dioxide from coal-fired power plant flue gasses, but the costs appear to 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.

A technique used recently is planting trees in numbers sufficient to absorb and fix the 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 into 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 wells are drilled, when gas is transported and when it is used are the key sources 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 combustion-based power plants. 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

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, disposal of waste products, and decommissioning of 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 and many state laws 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 debate over whether these reclaimed lands can sustain long-term productivity or re-establish the diversity of species characteristic of the 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. These are released into the atmosphere in the coal combustion process. The types and amounts of these pollutants released from a typical pulverized coal-fired plant burning Western coal are displayed in Table 9-3.

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. Water quality also can be affected if rainwater comes in contact with coal piles, sludge or other contaminated surfaces before entering the groundwater. These effects can be mitigated with the use of water purification systems and "zero discharge" plant designs.

The use of water in a coal plant also can affect fish and wildlife habitat when the water is withdrawn.

Waste Disposal

A typical pulverized coal-fired plant produces about 440 tons of solid waste per megawatt year, or about 25 tons per hour of operation. The waste is generally not classified as 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 lead in some waste, some vegetation has a difficult time growing in the waste. The sulfur removal process used in coal gasification plants reduces the solid waste production of these plants in comparison with conventional plants.

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 particular the hydropower portion of the system. These resources are being considered as the best way of "firming" nonfirm hydropower.[10] 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.

10. Nonfirm hydropower refers to that portion of hydropower that exceeds the amount produced at the critical water level (historical dry period). Because it depends on weather and cannot be guaranteed, it has not been counted among firm resources. This power plan discusses ways to back up a portion of this hydropower so it can be used as a firm resource.

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.

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 preceding 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.

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 Collection and Transportation

Because the biomass resources considered in this plan include only wood or agricultural residues, there would be no incremental environmental impact from growing or harvesting the fuel. The environmental effects of moving wood residues to power plants principally include the effects of increased truck or rail traffic from the collection area to the power plant.

Combustion of Fuel to Produce Electricity

Additional environmental effects from wood-fired generation, aside from the major air pollutants discussed above, are not significant. To the extent that logging residues are combusted under controlled power plant conditions rather than burned as slash, a net environmental benefit may accrue from use of this material as fuel.

Refuse-Derived Fuel

Refuse-derived fuel comes from garbage that has been sorted to eliminate non-combustibles, other undesirable elements and recyclable materials.

Fuel Handling

Because garbage is collected, whether used for fuel or not, the incremental effect of fuel handling is negligible.

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 biphenyls (PCBs). These pollutants can be controlled 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. One difficulty in arriving at consistent values is the ever-changing content of the stream of garbage.

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. The Environmental Protection Agency will be determining whether this ash should be treated as a hazardous waste. If this ash were determined to be hazardous, the cost of waste handling and the corresponding cost of electricity from refuse-derived fuel would increase. In addition, if the ash were judged to be hazardous, plant operators probably would be required to "concretize" the ash to make it less likely to leach toxins into the groundwater.

Biomass: Cogeneration

Wood Residue

Resources are the same as those discussed under biomass.

Fuel Collection and Transportation

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 Collection and Transportation

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 on unique aspects of nuclear plants.

Uranium Mining and Fuel Processing

Uranium ore, the fuel source for nuclear power plants, is extracted by surface or open pit mining. Exploration can involve drilling, blasting and road building that may contaminate groundwater and disrupt wildlife habitat. Many of the same water pollution, air pollution and reclamation problems are encountered in uranium mining as in coal mining. However, the scale of uranium mining is substantially smaller 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. They must be disposed of properly to avoid contamination of water sources or transportation by the wind. Electrical energy is used for the fuel-enrichment process, 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

This discussion is not unique to the construction of nuclear plants. Any major construction project, including coal plants, can create the same effects. 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, construction costs often include compensation to the local community for the stresses put on the infrastructure. Significant local socioeconomic impacts already have 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 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. Disturbance of vegetation along the stream's banks also must be minimized.

Producing Electricity

The potential atmospheric effects of nuclear power plant operation are 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[11] 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 into 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.

There can be thermal impacts to aquatic organisms residing in surface waters, as a result of either raising the temperature of the receiving waters or by thermal shock accompanying changes in plant operation. Because of this, most contemporary power plants use the atmosphere as a heat sink. This is accomplished through 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 Washington Nuclear Projects 1, 2 and 3 and the Trojan nuclear plant all use some form of cooling tower for waste heat discharge.

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 wastes 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, and are one of the major reasons that public acceptance of nuclear power has waned. People are concerned not only about the existence of the waste, but the failure of the federal government to develop a permanent storage facility for the waste.

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

11. Noble gases are a class of chemically inert elements, gaseous at ambient temperatures and pressures. They include helium, neon, argon, krypton, xenon and radon.

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 thousandth of a rem.

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/year	0.14 millirem/year
Maximum Individual Organ Dose from Iodine and Particulates	3.4 millirem/year	0.14 millirem/year

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 on the physical and chemical characteristics of the waste 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 transportation accidents, accidental spillage and theft. Short of accidents or willful sabotage, the transfer of wastes is 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. However, 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 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 and 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.

Non-condensible gases come out of solution during the depressurization of geothermal fluids for steam formation. Principal release points 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 at low concentrations and toxicity at higher concentrations. Hydrogen sulfide poisoning affects the nervous system, causing excitement and dizziness and can result in respiratory failure at high concentrations. 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 equipment 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 on the quantity of waste water. Contemporary flash-steam and binary plants reinject spent geothermal fluids into 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 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 polluted accidentally, either chemically or thermally.

Table 9–5
Summary of Environmental Impacts for Representative Nuclear Power Plants

	Light Water Reactor[a]	
Air Residuals	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]
Water Use		
▪ 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]
Thermal Effects		
▪ Reject Heat (Btu)	45×10^{12}	60×10^9
Solid Waste		
▪ Spent Fuel (lb.)	50–60,000	70
Land Requirements		
▪ 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.

Noise Impacts

A number of significant noise sources are associated with development and use 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 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 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 geothermal 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, wellhead generators and small plants (5 to 10 megawatts) have different requirements for space than 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. Wellfields vary from 100 acres to several thousand acres. Wellfield 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.) Should the geothermal resource be 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

Construction

Solar thermal resources affect land use during construction and thereafter. A solar-thermal power plant would require about 18 acres per peak megawatt; about 60 acres per average megawatt of energy.

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, since 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 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 cleanup 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.

13. Luz International is a manufacturer of utility-scale solar generating facilities.

Solar Photovoltaic

Construction

A central-station solar photovoltaic power plant operating in the Northwest would require about 15 acres of land per peak megawatt; about 45 acres per average megawatt of energy.

Production of Electricity

Solar photovoltaics devices are 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 potentially could 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 zero.

Wind

Construction

A typical wind power plant will require about 30 acres per megawatt of capacity; about 90 to 150 acres per average megawatt of energy. Unlike solar power plants, a relatively small percentage would be disturbed and many pre-existing land uses could continue at the site.

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 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 in 1984 and again in 1987, 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. Because new large dams are not contemplated, the effects described below focus on high-head,[15] run of river[16] 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 construction period 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. Fish spawning and rearing habitat may be lost. 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 screens and bypass systems, water spills to aid fish for passage, fish ladders, establishment of minimum flows and flow augmentation.

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.

15. Head is the vertical height of the water in a reservoir above a turbine.

16. A run-of-river project has little or no storage and thus limited ability to regulate flows.

Another impact is nitrogen supersaturation caused by spilling of water over the dam. Sometimes 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.

Other impacts from operations of hydropower facilities include stranding of adult and juvenile fish and drying out nests when water fluctuates in the stream. These are important fish considerations when designing project components and developing operation criteria where anadromous[17] fish are found downstream of the project.

When a typical project goes online and offline, it causes flows to fluctuate 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. In this case, the 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 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 the following are involved: 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. In estimating the amount of hydropower potential for this plan, the Council eliminated national parks and wilderness areas from consideration.

In addition, on August 10, 1988, the Council adopted a proposal to designate approximately 44,000 miles of streams throughout the region as protected from new hydropower development because of their importance as critical fish and/or wildlife habitat. In adopting this proposal, the Council concluded that hydropower development in the designated areas would have major negative impacts that could not be mitigated and that protecting these resources is consistent with an adequate, efficient, economical and reliable power supply as required by the Northwest Power Act. 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 power plan excludes currently unlicensed hydropower development involving new water control structures in the Council's protected areas.

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. It can also reduce the forest land base and affect Indian religious sites. In addition, 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.

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 plan.

17. Anadromous fish are born in freshwater streams, migrate to the ocean to spend their adult lives, and return to spawn in streams where they were born. Examples are salmon and steelhead.

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) can be 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 taking 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 explain the relationship between indoor air quality and energy conservation. These studies show 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 whatever pollutant is present. Studies show 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 9-6 displays the physical quantities of air pollutants produced by each resource considered in this plan per megawatt-year of electricity produced. A question mark has been inserted where the quantities are currently not known. The effects of these pollutants will depend on 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. The figures of Table 9-6 include only the releases directly associated with plant operation. Other parts of the fuel cycle may result in additional releases of these pollutants.

The information presented earlier in the text of this document and the physical pollutants emitted to the air, shown in Table 9-6, are here 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 previously believed.

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 resource available to meet loads, even though coal's environmental effects appear to be greater than other alternatives. Also, it should be recognized that all resources have some environmental shortcomings, although some have fewer adverse effects.

The actual environmental effects of any plant will be based not only 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, for example, gas-fired plants are more likely to be placed closer to population centers because of their relatively less severe environmental impacts.

Coal

Coal-fired generation probably affects the environment more than any other resource considered in the Council's resource analysis. 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.

Improved coal technology, including fluidized bed combustion plants and coal gasification combined-cycle plants can significantly reduce the amount of pollutants emitted from coal-fired power plants (see Table 9-6). The Council assumes that new coal-fired power plants built to serve Pacific Northwest needs would employ advanced "clean coal" technologies. The reference coal-fired power plants used in this plan are gasification combined-cycle plants.

But, combustion of coal, even at relatively clean plants,[18] 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 any other resource. Coal plants also emit more particulates than every resource except biomass. Only biomass-fired power plants 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 chapter and Volume II, Chapters 7 and 8.

Disposal of ash sludge and flue gas desulfurization can require up to 1,400 acres of landfill for a conventional 500 megawatt pulverized plant. Because the ash contains toxic elements, revegetation can be difficult.

Because 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.[19] 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. Toxic constituents of coal can attach to particulates produced during the combustion of coal and be inhaled. On a per-megawatt basis, among electric generating resources, coal plants are 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, coal also is considered to be an environmental risk because of the uncertainty imposed by the fears of global warming. Coal combustion emits more carbon dioxide per unit of energy produced than other resources, with the exception of biomass-fired power plants. Table 9-6 shows that coal plants emit from 8,600 to 10,400 tons of carbon dioxide per megawatt a year. Wood biomass power plants also produce a considerable amount of carbon dioxide, but if replanted, 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. 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.

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18. Pulverized coal plant emissions considered here and shown in Table 9-6 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.

19. The Council's cost estimates for large power plants include an allowance for mitigation of socioeconomic impact.

Table 9–6
Common Pollutants Emitted into the Air (Tons per Megawatt per Year)[a]

Technology	Total Suspended Particulates	Sulfur Dioxides	Nitrogen Oxides	Carbon Monoxide	Carbon Dioxide
Small Pulverized Coal[b]	1.78	2.00	17.2	1.71	10,368
Large Pulverized Coal[b]	1.76	1.97	16.9	1.69	10,226
Atmospheric Fluidized Bed (Coal)[b]	1.60	1.80	15.3	1.54	9,313
Integrated Coal Gasifier Combined Cycle[b]	.6	.36	(2–6.5)	.15	8,626
Combustion Turbine (Natural Gas)[b]	.119	.029	7.87	1.91	5,000
Combined-Cycle Combustion Turbine (Natural Gas)[c]	.04	0	2.80	2.23	4,174
Combustion Turbine (Oil)[c]	1.45	10.3	4.99	5.65	8,006
Combined-Cycle Combustion Turbine (Oil)[c]	7.62	7.62	1.10	1.10	6,237
Cogeneration (Natural Gas)	d	d	d	d	d
Biomass Steam-Electric (Wood)[c]	1.88	.57	9.94	18.7	13,183
Cogeneration (Wood)	d	d	d	d	d
Municipal Solid Waste (RDF)[b,e]	.24	3.31	15.0	10.8	?
Municipal Solid Waste (Mass Burn)[b]	1.43	4.13	13.5	8.34	?
Nuclear	0	0	0	0	0
Geothermal (Flashed Steam)	f	.54[g]	f	f	26[g]
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] Emission levels are consistent with emission control technology assumed in Volume II, Chapter, 8.

[b] SOURCE: Joyner, Michael W., Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards. *Compilation of Air Pollutant Emissions Factors: v. 1 Stationary Point and Area Sources,* 1985. Coal Gasification Combined Cycle Power Generation G.A. Cremer and C.A. Brigens, Shell Oil Company.

[c] SOURCE: Bernow and Marron, Tellus Institute, Boston, Massachusetts. *The Treatment of Environmental Impacts in Electric Resource Evaluation: A Case Study in Vermont,* January 22, 1990.

[d] 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.

[e] Refuse-derived fuel.

[f] We have not found good emissions data for geothermal plants, probably because the effluents are so dependent on the chemistry of the geothermal resource and partly because of an assumption that closed-loop systems do not emit much to the atmosphere.

[g] These are emissions from CEEI's Coso units, which are thought to be typical.

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 9-6. Nitrogen dioxide levels from gas plants can be high, although selective catalytic reduction technology can reduce nitrogen dioxide to fairly low levels (five parts per million). This technology is not incorporated into the Council's reference plants. 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 carbon dioxide from gas-fired plants is about 40 percent of the amount from coal plants.[20] Gas-fired plants are second to coal in the net production of greenhouse gasses. Because of the global warming issue, gas-fired power plants impose some risk to developers of incurring costs for future mitigation of carbon dioxide. The effects of gas-fired power plants 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 9-6, and lesser effects of the natural gas fuel cycle on land and water.

Natural Gas as a Resource to Firm Nonfirm Hydropower

"Stand-alone" (i.e., non-cogenerating) natural gas-fired plants used in the Northwest 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 9-6. (The figures in Table 9-6 assume base-load operation.) In essence, each megawatt-year of firmed nonfirm hydropower 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 environmental impacts and risk of large ocean spills, as has been shown in massive spills in Alaska and off the coast of Africa. In addition to the transportation issue, oil combustion, though not resulting 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. This could result in requirements to retrofit the plants sometime in the future.

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 these generators emit about 70 percent of a coal plant's emissions. Although the amount of carbon dioxide emitted is large, as can be seen in Table 9-6, combustion of wood is a zero net contributor to greenhouse gasses if the biomass is regrown. 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. Concern about global warming might lead to increased wood burning, 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. Transportation of wood residues to the plant site can produce impacts related to truck or rail operation. To the extent that wood burning power plants use logging residue, combustion of this material under controlled power plant conditions would result in less environmental impact than slash burning of this material. The Council's analysis of the biomass resource considers only the use of biomass residues.

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 and shredded municipal solid waste 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 those addressed in Table 9-6, 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 9-6 go, these resources emit about the same level of particulates as coal plants and oil-fired plants. Sulfuric

20. In addition, leaks from natural gas burners and pipelines release some amount of methane, which also is a greenhouse gas.

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. Regardless of the estimated probabilities, nuclear power will continue to be judged by perception of risk. This affects the ability to develop new nuclear power plants.

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 development standards and zoning ordinances. From a regional planning perspective, these resources probably will not be significantly 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 and can conflict with nearby pristine and environmentally sensitive areas. Development of geothermal projects can require a large land area, and emissions from plants are potentially quite toxic. Emissions can be largely controlled by reinjection or by use of closed-loop binary systems.

The environmental effects from geothermal resources are judged to be about the same in relative severity as those from wood-fired generation. Both of these resource types are renewable, with some lag time, but they are not as environmentally sound as 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, wildlife and other important resource values. Those sites that are left have no known important fish or wildlife concerns, though other stream values may be affected by hydropower development. 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 judged 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 environmentally responsible resource of those considered. Its key environmental problem, indoor air quality, can largely be mitigated during conservation acquisition efforts.

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 whether a resource or measure is cost-effective. Quantifiable environmental costs and benefits are among the direct costs of a resource or measure. The Northwest Power 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, refer 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. Assemble an information base for each environmental cost and benefit that can be quantified that analyzes the amount of information available to quantify each cost or benefit, and an assessment of 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. Select a specific economic evaluation method 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. Describe and, if possible, quantify key physical and biological parameters for those environmental costs and benefits where it is not possible to develop monetary values.

H. Apply the evaluation methods and compile a record 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. Include all quantified environmental costs and benefits 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. Identify and describe, where no quantification on any terms is possible, the environmental costs and benefits, and assess 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.

CHAPTER 10

RESOURCE PORTFOLIO

Introduction

A resource portfolio can be thought of in the same terms as an investment portfolio. An investor seeks a mix of stocks that will produce a high return on investment with acceptable levels of risk. In the development of a resource portfolio the Council's objective is to find the mix of resources that will keep the region's power cost as low as possible while providing flexibility to adapt to an uncertain future. Both types of portfolios manage risk by diversification of their investments. Additionally, both must use judgment to include in their decisions those attributes that cannot be quantified.

A power plan resource portfolio is frequently thought of as simply four different resource schedules, one for each of the four deterministic load scenarios. While a set of specific resource schedules for specific load paths is one way of describing a resource portfolio, it is much more than that. It is more appropriate to think of the portfolio as a set of resource availabilities and costs, resource development priorities, and rules for resource acquisition decisions. The information in the portfolio is intended to be used in conjunction with evolving load forecasts to guide the decision-making process toward the most economical resource decisions as the region's energy future unfolds. The portfolio represents a strategy for investment in the region's energy future.

The resource portfolio development process plays several roles in the Council's planning process. First, this is where the demand and supply side data comes together in a system perspective. The portfolio is the vehicle that integrates the conservation supply assessment, the generating resource assessment, the demand forecasts and associated uncertainty with the economics and physical characteristics of the existing hydro-thermal system in the Pacific Northwest. Resources compete for inclusion in the portfolio based on their ability to adapt to load uncertainty and to operate efficiently in conjunction with the Pacific Northwests' hydro-based generating system.

The process also provides a platform to pose questions regarding some of the other major uncertainties affecting Northwest power planning. In the development of this plan, many alternative scenarios regarding the supply and performance of future resources, environmental costs and regulatory restrictions, and the level of long-term fuel prices were evaluated. Alternative resource portfolios were developed to respond to these scenarios and evaluated in terms of their expected costs, economic risk and environmental consequences. This framework can be used to formalize some of the trade-offs inherent in power planning. For the issues that are not quantifiable, the Council exercises its judgment to determine the role of the various resources in the portfolio.

Perhaps the most significant use of the portfolio is its contribution to the Action Plan. The portfolio analysis and studies of alternative scenarios produce a large amount of information regarding the probability and magnitude of decisions that will need to be made to maintain a reliable power system. This information flows into the development of the Action Plan and recommendations for near-term actions on conservation programs and generating resources. Because both conservation and generating resources have lead times, actions to secure resources frequently must be taken well in advance of need. While the development of the portfolio necessarily uses a long-term view to capture all of the economic impacts of long-lived resources, it is the short-term actions embodied in the portfolio that are the most important. The resource decisions made between the present and the next plan[1] are the real commitments to the energy future of the region. Decisions that are required five or 10 years into the future will have significant opportunity for review and debate. The Council realizes that it is extremely unlikely that the resources ultimately acquired over the next 20 years will

1. The Northwest Power Act stipulates that the Council will review its power plan at least every five years.

be the same as those in the portfolio. However, the portfolio does provide the basis for resource decisions over the next few years. Once implemented, these decisions will be irreversible.

The portfolio also is used to develop marginal or avoided cost estimates for use as benchmarks in the resource acquisition process. These can be used to judge the cost-effectiveness of specific resources that may not have been treated directly in the resource portfolio analysis. Avoided costs are also needed in the design of cost-effective conservation programs. See Volume II, Chapter 14, Resource Cost-Effectiveness, and page 55 of this chapter for a discussion of resources outside the portfolio.

In developing a resource portfolio, the Council's primary objective was to achieve the lowest present-value system cost[2] across the wide range of future uncertainty faced by the region. In addition, because future events are not guaranteed to turn out as forecast, the Council's portfolio continues to exhibit a high degree of flexibility, allowing opportune responses to unforeseen changes. This helps to maintain a reliable, economic power system. The Council believes the concept of risk management should play an important role in the resource decision-making process. The flexible planning strategy that has characterized previous Council plans is emphasized again in the 1991 Power Plan.

Generating resource characteristics that lead to enhanced flexibility and reduced risk are, primarily, short lead times and small unit size. Shorter lead times reduce the period over which the need for new resources must be forecast, and allow resource sponsors to move closer to the point of actual need before committing large amounts of capital for resource construction. Shorter lead times produce a greater likelihood that resources will be useful once they are ready for service. Resources with small plant sizes would allow the region to make many smaller decisions rather than a few large ones, and provide the ability to match resource development and load growth more closely.

The concept of resource options was developed and emphasized in the Council's first plan. An important objective of this concept is the reduction of resource lead times. The options concept permits the region to enter into the preliminary stages of resource development, siting, licensing and design based on a relatively high projection of future load growth. This strategy is expected to prove cost-effective because the cost of acquiring options is low compared to the cost of actual resource construction.

The options concept leads to a second decision point regarding the appropriate time to begin constructing a resource. After option acquisition, load forecasts would continue to be updated, and the projected need for the resource re-evaluated. If loads have not grown sufficiently to justify entering construction, the option would be held until it was either appropriate to construct the resource or the option was lost. The options concept enhances the flexibility of the Council's resource portfolio and warrants additional analysis and policy development. Over the planning horizon, the ability to create resource options will improve the ability to match the rate of resource development with resource need and thereby reduce the cost of the resource portfolio.

Most of the resource portfolio studies were performed with a computer model referred to as ISAAC.[3] ISAAC was developed jointly by staff from the Council and Bonneville, with support from the Pacific Northwest Utilities Conference Committee and the Intercompany Pool. It is currently used by both the Council and Bonneville for resource planning studies. ISAAC is used in the portfolio development process because of its ability to treat several of the major uncertainties that affect Northwest power planning. The model is used in decision analysis studies to evaluate the risks associated with the resource portfolio or a particular set of decisions and is useful in developing risk management strategies.

Unless otherwise noted, all costs mentioned in this chapter are expressed in January 1990 dollars. This applies to all resource levelized cost values, either real or nominal, and to any present value results for the portfolio studies.

Resource Portfolio Development

Process Overview

The Council's resource portfolio development process consists of a number of interrelated activities. These are shown graphically in Figure 10-1 and are summarized below.

Load Forecasts

The process began with development of electricity demand forecasts for the region. Five forecasts were developed, each representing a possible regional future. A probability distribution for future loads also was developed. In order to focus on the obligations of the Bonneville administrator, the forecasts also were broken down into demands of the public and investor-owned utilities. Volume II, Chapters 5 and 6 provide a detailed description of the forecasting process and its results.

2. System cost is defined as an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, distribution and transmission costs, waste disposal costs, end-of-cycle costs, fuel costs and quantifiable environmental costs. System cost also takes into account projected resource operations based on appropriate historical experience with similar measures or resources.

3. ISAAC is an acronym for Integrated System for Analysis of Acquisitions. Volume II, Chapter 15 contains a description of the model.

Determination of Resource Availability

Information from the load forecasts and the avoided cost estimates were used to screen resources for the portfolio analysis. Initial estimates of the amounts of cost-effective resources were developed for generating resources and conservation programs. For many conservation programs, the amount of efficiency improvement available depends on the level of economic activity modeled for that sector in the load forecast. This correlation between conservation availability and load level is used in the portfolio analysis. For a full discussion of the conservation and generating resource potential see, respectively, Volume II, Chapters 7 and 8.

Portfolio Analysis

The load forecast range, its probability distribution, and the conservation and generating resource availabilities and costs were used with ISAAC to develop a least-cost resource portfolio. ISAAC is used here because it incorporates the effects of long-term load uncertainty, hydro uncertainty, resource lead times, conservation program ramp rates, seasonality and system operation impacts into the cost-effectiveness analysis. The process involved several iterations with the forecasting and resource screening activities to produce consistency among the portfolio, loads and electricity prices, and conservation energy potentials. After development of a least-cost portfolio, alternative portfolios were developed to address the major resource uncertainties facing Northwest power planning. These are used in development of the Action Plan, and avoided costs were calculated based on the least-cost portfolio resources.

Load Treatment

Volume II, Chapter 6 describes the development of the four demand forecasts in detail. These forecasts provide the starting point for the portfolio analysis and obviously are a critical piece of information. However, these four specific forecasts are not used directly in the analytical process. Rather, they are incorporated into the analysis through definition of the probability distribution for regional loads.

As for any specific forecast, the likelihood is extremely small that future regional load will evolve exactly along any one of the four specific forecast paths. However, because of the philosophy underlying their development, the forecasts can be used to define a probability distribution for future electricity demand. The forecasts were developed in such a way that future load outcomes either below the low forecast or above the high were believed to have probabilities so low as to justify exclusion for planning purposes. In addition, the medium-low and the medium-high forecasts define the range of most likely load outcomes. These characteristics can be represented with the trapezoidal probability distribution shown in Figure 10-2. This

Analytical Flow

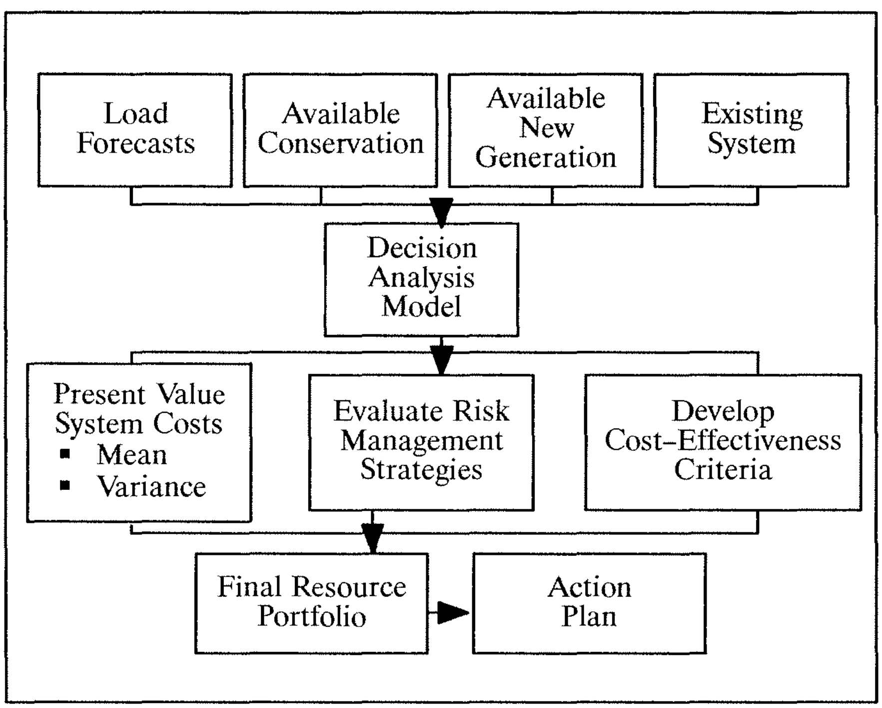


Figure 10-1
The Resource Portfolio Analysis is an Interrelated Process

Trapezoidal Distribution

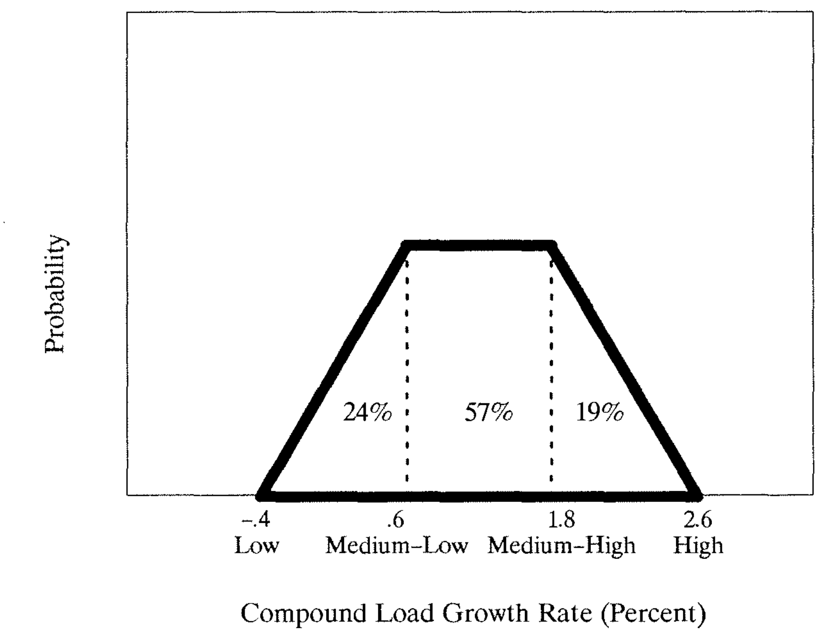


Figure 10-2
Loads Between the Medium-Low and Medium-High are Equally Likely

distribution, expressed in terms of 20-year compound growth rates, has a uniform probability of occurrence for loads between the medium-low and medium-high, with probabilities dropping off linearly to zero in both the low and the high forecasts. This is a continuous distribution, meaning that any load outcome across the entire range would be possible. The probability of a load occurrence between the low and medium-low is 24 percent; between the medium-low and medium-high, 57 percent; and between the medium-high and high, 19 percent. As described in Volume II, Chapter 6, the frozen-efficiency forecasts are used in the portfolio analysis to avoid the double counting of conservation energy savings.

Another component of load uncertainty included in the portfolio analysis is that associated with the direct service industries. In the detailed demand forecast range, firm direct service industry loads range from about 500 average megawatts in the low load scenario to about to 2,300 average megawatts in the high scenario (see Volume II, Chapter 6). The portfolio analysis uses approximately this same upper and lower limit for direct service industry load, but assumes no correlation with other loads. ISAAC contains an aluminum submodel that treats aluminum prices as a random variable. Aluminum prices are assumed to be driven by world markets and are determined independently from regional economic conditions. Aluminum loads are developed in response to these aluminum prices in conjunction with electricity prices. ISAAC's aluminum submodel was calibrated to result in approximately the same range of loads for the direct service industry as in the detailed demand forecasts.

Resource Requirements

Comparing the Council's demand forecasts with the energy capability of existing system resources over time yields an estimate of surplus and deficits the region would face if no new resources were developed. The loads used in this calculation are the frozen-efficiency forecasts described in Volume II, Chapter 6. The estimates for the capability of existing resources are based largely on the *1991 Northwest Regional Forecast*, published by PNUCC in March 1991 (see Volume II, Chapter 4). The existing resource capability includes adjustments for firm imports and exports, expected retirement of existing thermal plants, and the scheduled return of Canadian Entitlement energy to British Columbia. The existing system capabilities are based on critical water conditions. There are no adjustments made for the potential reduced capability of the system hydropower facilities due to endangered species mitigation actions. Adjustments to the capability of the existing system will be incorporated into the plan if and when these events occur.

Figure 10-3 depicts the regional load/resource balance under the four deterministic load scenarios. Because there is some uncertainty about current levels of demand, the load/resource balance shows a range at the beginning of the planning horizon in 1991. On average, it shows a small surplus, but ranges from a surplus of about 1,000 average megawatts in the low scenario to a deficit of about 500 average megawatts under high loads. Under low loads, the region is significantly surplus over the entire 20-year planning horizon with no new resource additions. If high loads occur, the region will need to develop over 13,000 average megawatts to maintain load/resource balance. One thing to note from this graph is how quickly the region is likely to need resources to maintain system reliability. In both the high and medium-high scenarios, resources are needed almost immediately. In the medium-low, the point of need is about 1999.

Figure 10-4 takes a closer look at the first 10 years of the planning horizon using a probabilistic perspective. This is a scatter diagram where each dash represents a surplus or deficit point that occurs over the 100 separate load paths typically used in the portfolio analysis. The probability distributions for the loads underlying each point conform to those discussed earlier. Note that these are the surpluses or deficits that would occur if no new resources were added to the system. The solid line represents the average load/resource balance through time. This figure indicates that the expected point of need for new resources on a regional basis is about 1993.

Figure 10-5 shows frequency distributions of the potential surpluses and deficits for 1995 and 2000. It provides information about the probabilities of seeing a surplus or deficit of a particular magnitude. The values on the vertical axis represent the midpoints of the range used for each bar. For instance, the estimate for the probability of a surplus in 1995 between 500 and 1,500 average megawatts is represented by the length of the 1,000 megawatt bar, or 18 percent. The cumulative probability is the probability of seeing a load/resource balance of less than the upper bound of the interval. For example, in 2000 the probability of seeing a deficit of 3,500 average megawatts or less is 76 percent. Another interpretation is that there is a 24 percent chance of needing more than 3,500 average megawatts of new resource to maintain load/resource balance. The mean value for the amount of new resource needed is 520 average megawatts in 1995 and 2,230 average megawatts in 2000.

The Northwest Power Act requires the Council to forecast the electrical demand and plan for the resources to serve Bonneville's customers. The actions needed to meet the administrator's obligations are an important part of the plan. To date, only relatively small loads have been placed on Bonneville by the region's investor-owned utilities, and there currently are no long-term power sales contracts for significant amounts of energy. For most of the portfolio studies, the Council has assumed the investor-owned utilities place no additional load on Bonneville. Except for studies concerning regional cooperation, the assumption used throughout the analysis is that Bonneville and the investor-owned utilities will plan for and acquire resources independently.

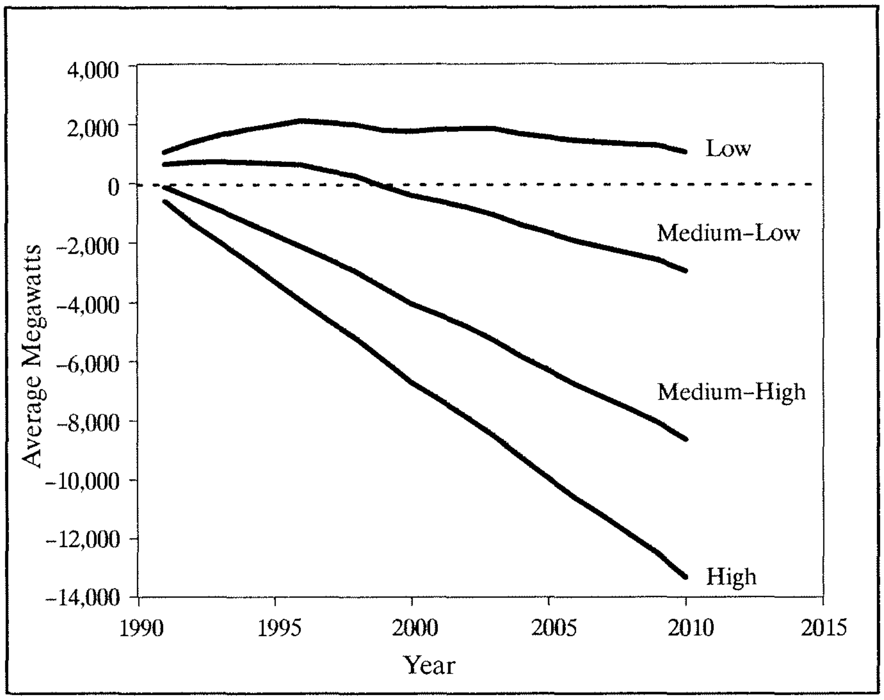
Figure 10-6 shows the range of energy requirements for Bonneville's public utility and direct service industry customers. These include the loads and resources of the region's generating public utilities. In the short term, Bonneville and the public utilities are in approximate load/resource balance. Depending on load growth, Bonneville can maintain balance for a period of time by exercising the recall provisions of current out-of-region contracts. Bonneville has about 300 average megawatts of energy that can be gained through contract recall and supplemental energy provisions. In the portfolio analysis, this is one of the first actions taken by Bonneville, if needed. In aggregate, Bonneville and the public utilities need no new resources in low loads and very few resources in the higher probability medium-low scenario. Under high loads they could need as much as 5,300 average megawatts. Figure 10-7 shows the frequency distributions for Bonneville and public utility resource requirements in 1995 and 2000.

Finally, Figures 10-8 and 10-9 portray an estimate of the load/resource balance picture for the combined systems of the six investor-owned utilities in the Northwest. For planning purposes, the Council treats the private utilities as a pool. In fact, these are unique companies facing a diverse set of load growth and existing resource conditions, and it would be an error to infer much about the load/resource conditions of any individual company from this graph. However, the aggregate need for resources shown here is representative of expectations of the investor-owned utilities as a whole, and is appropriate for regional planning.

Comparison of Figures 10-6 and 10-8 shows that the Bonneville/public utility system and the investor-owned utilities are currently in about the same load/resource balance conditions. However the investor-owned utilities are forecast to have a higher proportion of regional load growth in their service territories. Much of the early resource development in the region is likely to be driven by investor-owned utility needs. Over the planning horizon, it is expected that over 60 percent of new resource additions will go to serve investor-owned utility needs.

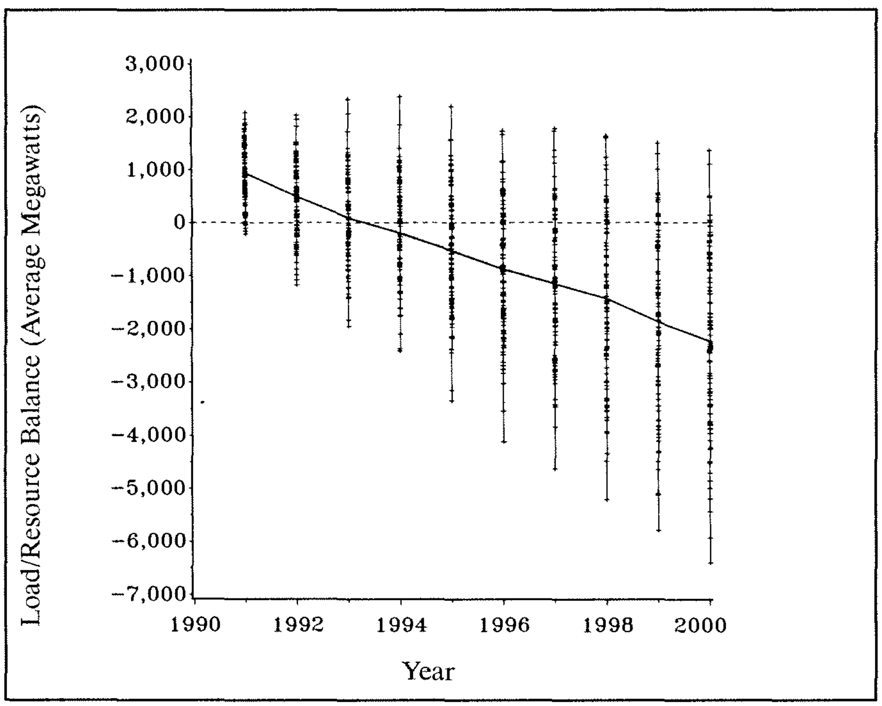
Regional Need

Figure 10-3
Regional Resource Requirements



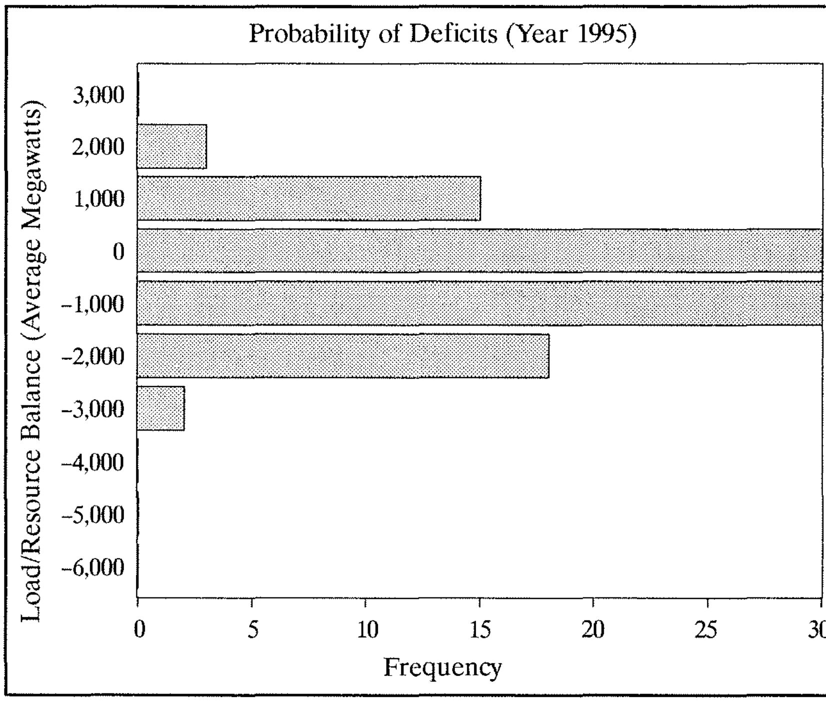
Uncertain Need

Figure 10-4
Uncertainty in Regional Resource Requirements

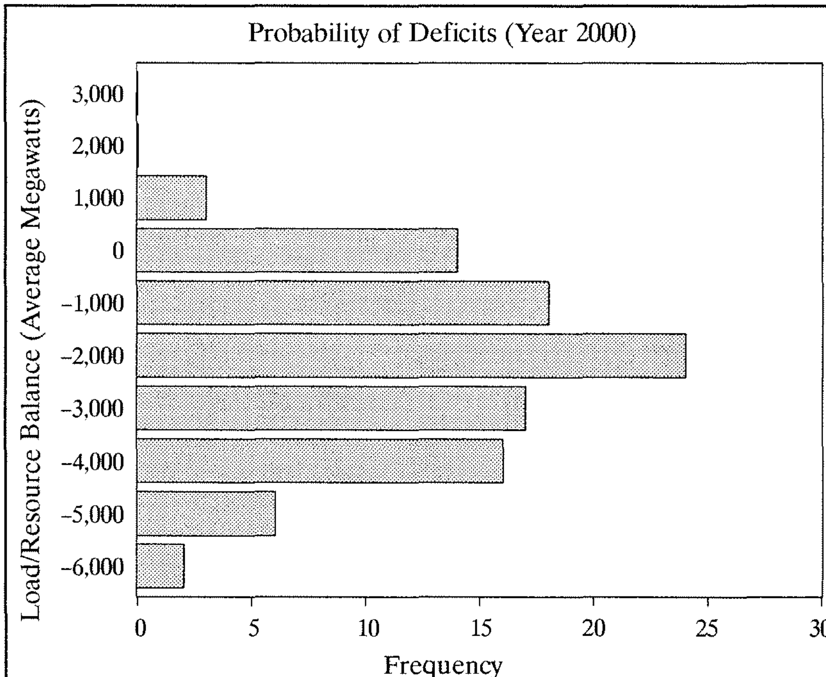


Probability of Regional Need

Figure 10–5
Distributions of Regional Resource Requirements



Load/Resource Balance	Prob	Cum Prob
3,000	0	0
2,000	.03	.03
1,000	.15	.18
0	.32	.50
-1,000	.30	.80
-2,000	.18	.98
-3,000	.02	1.00
-4,000	0	1.00
-5,000	0	1.00
-6,000	0	1.00



Load/Resource Balance	Prob	Cum Prob
3,000	0	0
2,000	0	0
1,000	.03	.03
0	.14	.17
-1,000	.18	.35
-2,000	.24	.59
-3,000	.17	.76
-4,000	.16	.92
-5,000	.06	.98
-6,000	.02	1.00

Public Utility Need

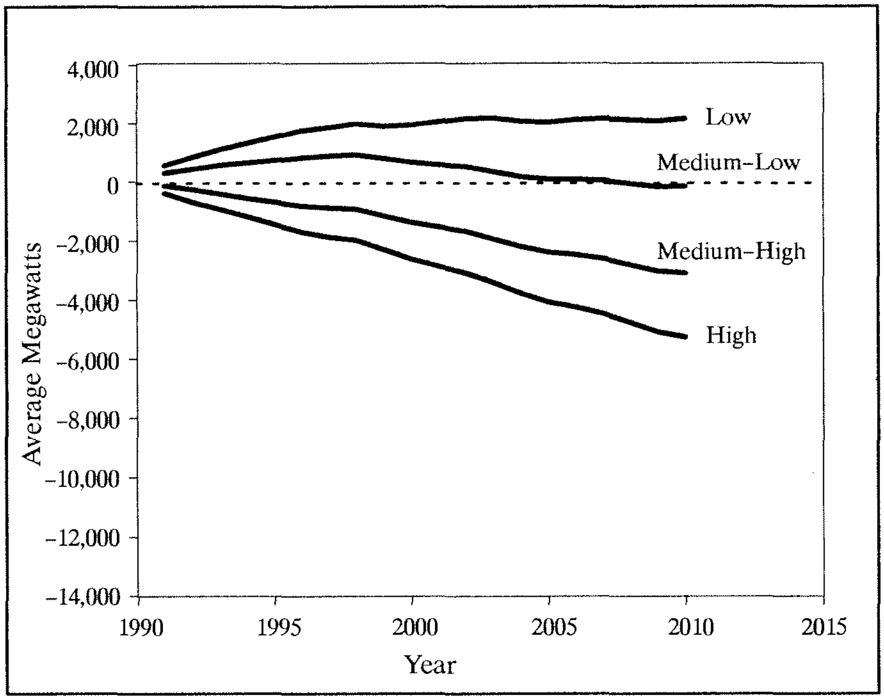


Figure 10-6
Bonneville/Public Utility Resource Requirements

Resources Available

The Council has undertaken a detailed analysis of the conservation program measures and generating resource alternatives available to meet the region's energy needs over the planning horizon. These analyses were described in detail in Volume II, Chapters 7 and 8. A summary of the results is shown in Table 10-1. This table shows the stand-alone levelized cost and the amount of energy estimated to be available across the load forecast range for each resource. For conservation programs, the energy potential is frequently correlated with load growth, while for generating resources, the amount of energy available does not vary with the load forecast. Many of the conservation program potentials are driven by the level of economic activity in their sectors; for example, the rate of new building starts affects the energy available from the model conservation standards. As the economic activity driving the forecasts increases, more new buildings are constructed, providing more potential for conservation savings. The energy potential of the conservation programs has been adjusted for transmission and distribution line losses equal to 7.5 percent.

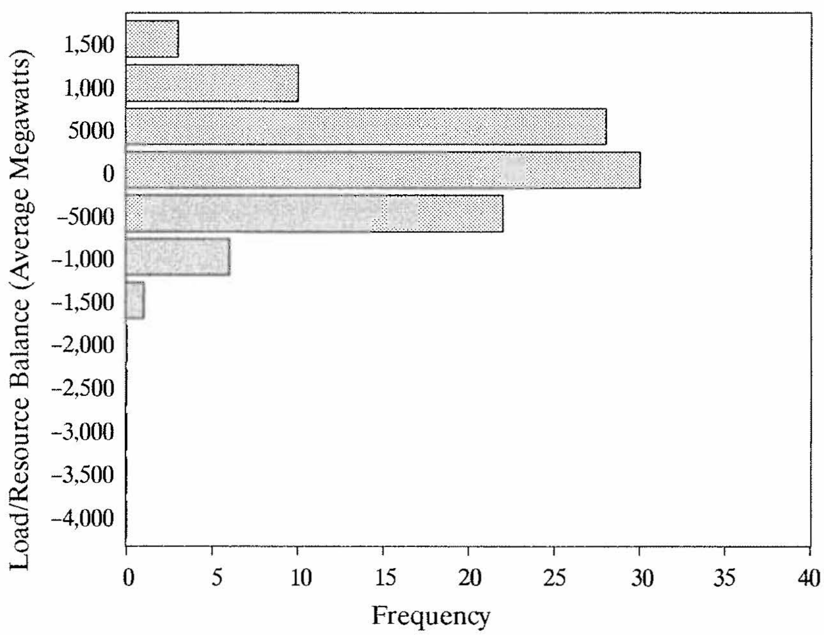
The real levelized costs for all conservation programs and generating resources are based on the portfolio assumptions for physical lives. To allow comparison of resources on a nominal basis, the nominal levelized costs have all been normalized to a 40-year physical life (see Volume II, Chapter 14). Costs for the conservation programs include an administrative cost estimate of 20 percent of capital cost. They also reflect a 2.5 percent credit for the avoidance of transmission and distribution investment and the 10 percent cost-effectiveness credit defined in the Act.

Note also that, except for the non-discretionary conservation programs, the energy values in Table 10-1 are not the amount of resource actually acquired in the four deterministic load forecasts. The energy values shown here represent resource supply potentials. The actual energy acquired for individual resources is determined by need for power under the various load scenarios, resource priority order, lead time, and constraints on resource development. The data from Table 10-1 can be used to develop an aggregate supply curve for the portfolio resources. This supply curve is shown in Figure 10-10.

Probability of Public Utility Need

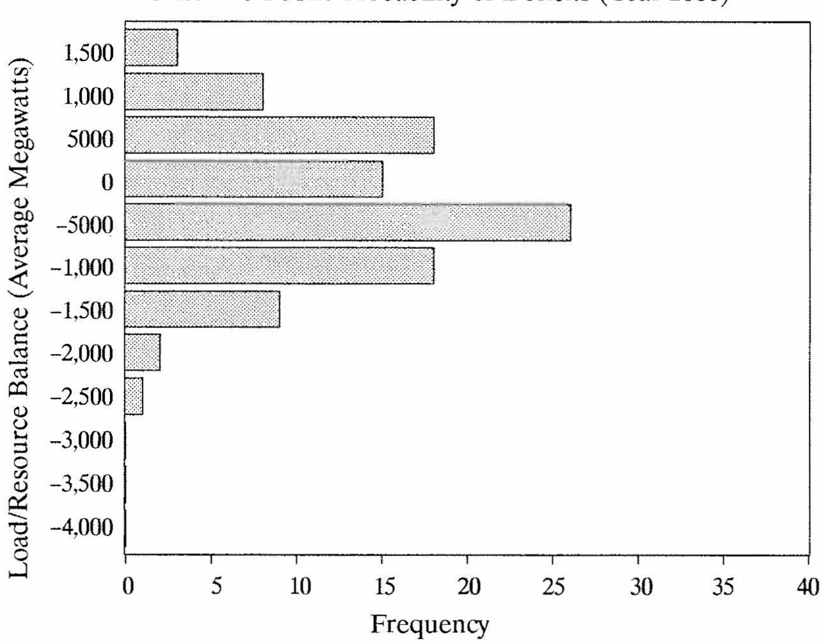
Figure 10-7
Distributions of Public Utility Resource Requirements

Bonneville/Public Probability of Deficits (Year 1995)



Prob	Cum Prob
.03	.03
.10	.13
.28	.41
.30	.71
.22	.93
.06	.99
.01	1.00
0	1.00
0	1.00
0	1.00
0	1.00
0	1.00

Bonneville/Public Probability of Deficits (Year 2000)



Prob	Cum Prob
.03	.03
.08	.11
.18	.29
.15	.44
.26	.70
.18	.88
.09	.97
.02	.99
.01	1.00
0	1.00
0	1.00
0	1.00

Private Utility Need

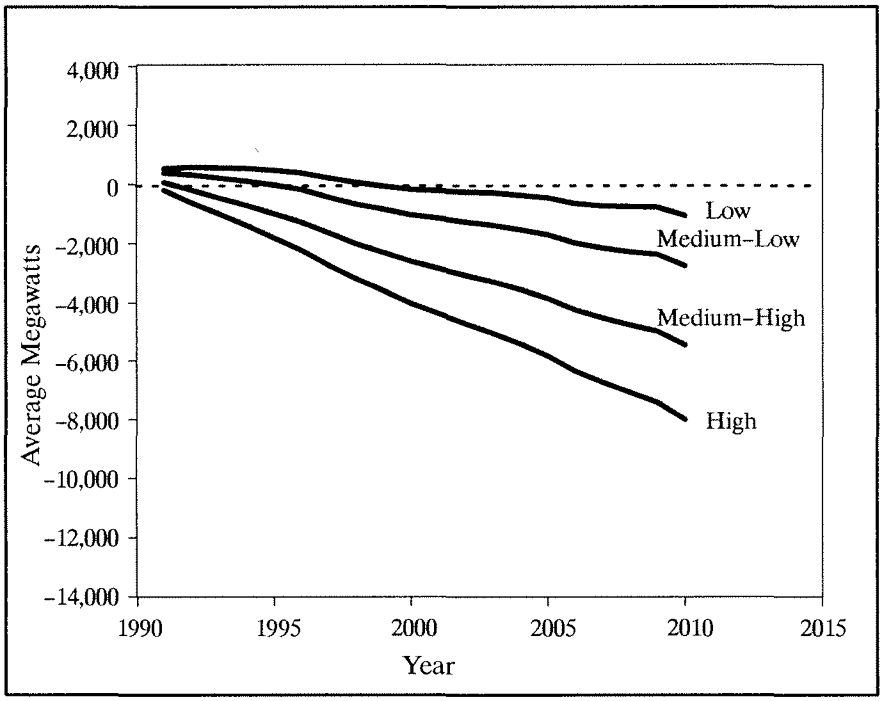


Figure 10-8
Investor-Owned Utility Resource Requirements

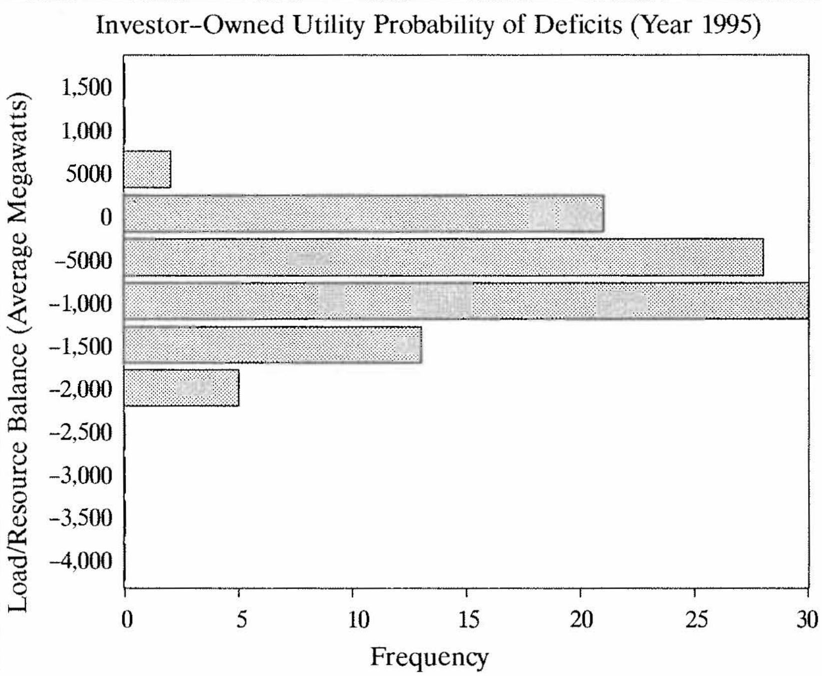
The conservation programs listed in Table 10-1 are classified as either "discretionary" or "non-discretionary." Non-discretionary programs are used in the portfolio analysis to model implementation of building and appliance codes, or the forced acquisition of cost-effective lost-opportunity resources. The development rates for the non-discretionary programs are not subject to program management in response to resource need. These programs produce energy savings regardless of need. For example, once fully incorporated into building codes, the level of savings from the model conservation standards would be driven primarily by the number of building starts. The standards automatically would produce energy savings across the entire load range. They would produce more energy in the high scenarios than in the low ones, but would produce a small amount of energy savings in the low scenarios even though no additional savings are required for the region in low-load conditions. This automatic correlation of savings produced to load level can add to the value of a resource and is captured in the portfolio analysis. Additionally, all non-discretionary programs have equal and top priority in the resource development order in the portfolio analysis.

Discretionary programs are those programs whose development is managed in response to need. These programs are targeted primarily at the existing sectors (e.g., existing industrial or existing commercial) where a savings potential already exists and can be developed as needed. Delaying implementation of these programs is not likely to produce large lost-opportunity impacts. These are programs that are likely to be subject to direct program management and whose energy contributions can be managed in response to forecast need.

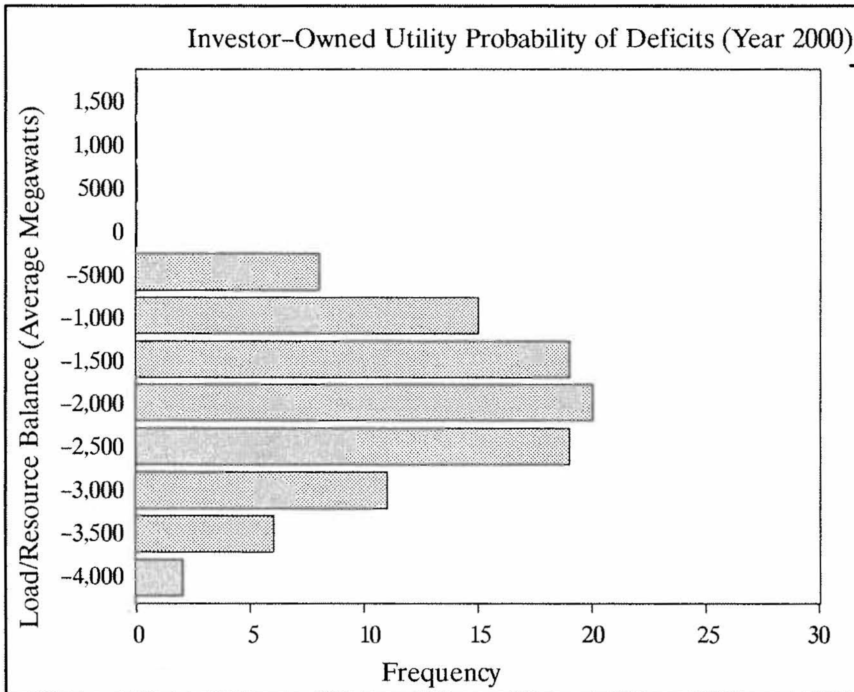
The acquisition of discretionary conservation in the portfolio modeling is controlled through a set of acceleration and velocity parameters defined for each program. These allow the programs to be modeled much as the movement of a car would be, with the activity level of a program analogous to the velocity of the car. Each program has an upper limit to its activity level (maximum velocity) and constraints on how quickly the activity level can change (acceleration and deceleration). High accelerations and velocities mean a program is quite flexible and energy could be acquired quickly. Low values indicate slow acquisition rates and difficulty in changing program activity levels. A minimum viable activity level to maintain the program after start-up is also specified. Accelerations and velocities used for the discretionary programs are shown in Table 10-2.

Probability of Private Utility Need

Figure 10-9
Distributions of Investor–Owned Utility Resource Requirements



Prob	Cum Prob
0	0
0	0
2	.02
.21	.23
.28	.51
.31	.82
.13	.95
.05	1.00
0	1.00
0	1.00
0	1.00
0	1.00



Prob	Cum Prob
0	0
0	0
0	0
0	0
.08	.08
.15	.23
.19	.42
.20	.62
.19	.81
.11	.92
.06	.98
.02	1.00

Table 10-1
Resource Cost and Availability (1990 Cents/kWh, Average Megawatts)

	Levelized Cost		Energy Available			
	Real	Nominal	Low	Medium-Low	Medium-High	High
Non-Discretionary Conservation						
▪ Water Heat	1.79	3.52	302	362	406	472
▪ New Commercial	1.86	3.66	207	280	460	566
▪ Commercial Remodel and Rehabilitation	2.32	4.57	81	112	152	143
▪ New Single-Family Residential	3.13	6.17	33	71	127	213
▪ New Manufactured Housing	3.28	6.45	81	125	146	131
▪ New Multifamily Residential	3.39	6.67	14	16	16	20
▪ New Residential Lighting	4.02	7.92	15	29	39	56
▪ Water Heater Heat Pump	4.06	8.00	32	61	93	136
Discretionary Conservation						
▪ Conservation Voltage Regulation	.70	1.38	100	100	100	100
▪ Industrial (Block 1)	1.34	2.63	235	296	375	491
▪ Irrigation	2.31	4.55	43	43	43	43
▪ Transmission and Distribution Efficiency Improvements	2.59	5.11	200	200	200	200
▪ Industrial (Block 2)	2.67	5.27	161	190	250	307
▪ Existing Commercial	2.74	5.40	490	540	640	730
▪ Multifamily Residential Weatherization	3.19	6.28	57	57	57	57
▪ Single-family Residential Weatherization	3.23	6.36	124	124	124	124
▪ Existing Residential Lighting	4.46	8.79	26	26	26	26
▪ Aggregate High Cost Block	5.76	11.35	108	220	331	443
Generating Resources						
▪ Hydro Efficiency Improvements	1.12	2.20	110	110	110	110
▪ Small Hydro 1	2.53	4.98	90	90	90	90
▪ Hydrofirming (Combined-Cycle 1)	3.34	6.58	1,070	1,070	1,070	1,070
▪ Hydrofirming (Combined-Cycle 2)	3.34	6.58	1,430	1,430	1,430	1,430
▪ WNP-3	3.69	7.28	868	868	868	868
▪ Thermal Efficiency Improvements	3.74	7.37	56	56	56	56
▪ Cogeneration 1	3.81	7.51	480	480	480	480
▪ Cogeneration 2	3.87	7.61	57	57	57	57
▪ WNP-1	4.09	8.05	818	818	818	818
▪ Municipal Solid Waste	4.09	8.05	30	30	30	30
▪ Small Hydro 2	4.17	8.22	100	100	100	100

Table 10–1 (cont.)
Resource Cost and Availability (1990 Cents/kWh, Average Megawatts)

	Levelized Cost		Energy Available			
	Real	Nominal	Low	Medium–Low	Medium–High	High
Generating Resources (cont.)						
▪ Cogeneration 3	5.25	10.34	1,130	1,130	1,130	1,130
▪ Wind 1	5.33	10.50	29	29	29	29
▪ Geothermal	5.42	10.67	350	350	350	350
▪ Eastern Montana Coal Gas	5.45	10.73	1,704	1,704	1,704	1,704
▪ Small Hydro 3	5.64	11.12	130	130	130	130
▪ Eastern Washington Coal Gas	5.71	11.25	745	745	745	745
▪ Cogeneration 4	5.74	11.31	540	540	540	540
▪ Eastern Oregon Coal Gas	5.83	11.49	745	750	750	750
▪ Western Washington/Oregon Coal	5.93	11.68	750	750	750	750
▪ Nevada Coal Gasification	6.20	12.22	716	716	716	716
▪ Wind 2	6.26	12.33	376	376	376	376
▪ Small Hydro 4	6.93	13.65	90	90	90	90
▪ Biomass	7.36	14.49	90	90	90	90
▪ Wind 3	7.99	15.73	253	253	253	253

Total Supply Curve

Figure 10–10
How Much at What Cost?

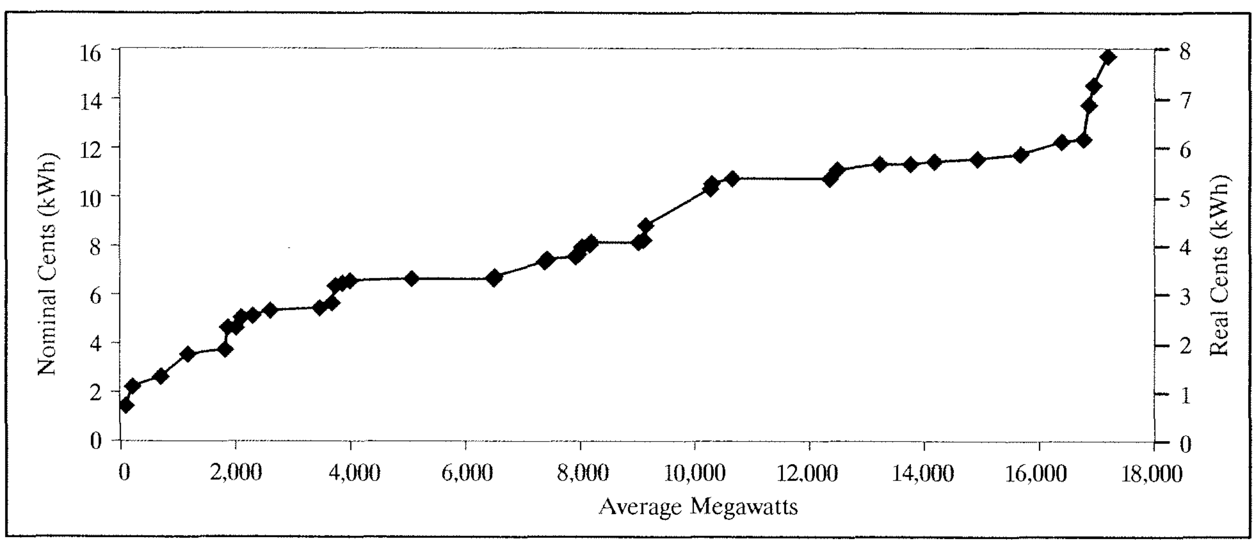


Table 10-2 Discretionary Conservation Development Constraints				
	Minimum Viable (%/yr.)	Maximum Acceleration (%/yr./yr.)	Maximum Deceleration (%/yr./yr.)	Maximum Rate (%/yr.)
Residential Weatherization	4	5	5	12
Residential Lighting	4	5	5	12
Existing Commercial	2	2	2	6
Industrial	0	2	2	6
Agriculture	1	2	2	4
Conservation Voltage Regulation	0	10	10	10
Transmission and Distribution	0	5	5	5

Resource Priority Studies

The estimates of resource availability in Table 10-1 can be thought of as individual investment opportunities to be used in developing a regional resource portfolio. A number of cost-effectiveness studies were performed using ISAAC to determine the least expensive order for resource development. The most cost-effective pattern of resource development is likely to differ from that suggested by the stand-alone levelized costs in Table 10-1 due to factors that affect a resource's interaction with the system but are not captured in the accounting for the levelized cost calculations. These include factors such as lead time, unit size, seasonality, dispatchability, fixed/variable cost ratios, firm versus nonfirm output and others.

The studies to determine the least-cost order for resource development were conducted by changing priority orders and comparing pairs of programs and generating resources until the order was found that led to lowest expected value system cost. This priority-order analysis involved only the discretionary conservation programs and generating resources. The non-discretionary programs were excluded from the priority order tests; however, they were included in the model runs to ensure that their system effects and impact on the cost-effectiveness of other resources would be included. Each study was run across 100 different future load paths.

The initial priority order was based on levelized cost estimates for the programs and resources, and the process allowed the generating resources to compete with conservation programs for priority order. A limit of at least a $5 million present value improvement in system cost was imposed judgmentally as the minimum improvement to justify a switch in priority-order between two competing programs and/or resources. This is on a total system cost approaching $50 billion and is considered to be about the precision limit of a model such as ISAAC.

Except for the amount of energy available for several of the resources, the conservation program assumptions for this analysis were consistent with the data described in Volume II, Chapter 7, and generating resource assumptions were consistent with Volume II, Chapter 8. For programs and generating resources in which the energy available was less than 300 average megawatts, the energy availability for these studies was raised to 300 average megawatts to ensure that the system effects of the resource would be captured in the present values. This increase in energy availability pertains only to these priority order studies. After the priority order was determined, the energy limits were again set back to those in Table 10-1 for further portfolio analysis. All sponsorship and financing assumptions were consistent with those described in Volume II, Chapter 13.

The results of this analysis are shown in Table 10-3. This is the priority order that was found to produce the lowest expected present value system cost across the entire load range, under the Council's base data assumptions and given the constraints mentioned above. This order was used as the starting point for further portfolio analysis, sensitivity analysis and development of Action Plan items. As stated earlier, the non-discretionary programs are all given equal and top priority in resource development.

The resource portfolio priority order shown in Table 10-3 represents a general order for development of resources during periods of acquisition. It does not mean that all of the potential of one type of conservation program or generating resource should be exhausted before moving to the next. Constraints on program and generating resource development rates and lead times will require parallel development paths for many of the resources in the portfolio.

Additionally, the methodology used in this analysis necessarily treats programs and resources as generic blocks. For instance, all of the potential cogeneration units within a block have the same physical characteristics, capital costs, operating costs, lead times, seasonal distributions, etc. In reality, there are likely to be significant differences between individual cogeneration installations competing for resource acquisition. In the actual acquisition decision, all projects should be evaluated on their own merits, taking into account their own unique characteristics (see Volume II, Chapter 14).

Option and Build Decision Rules

In addition to the order of resource priorities, two other decision rules are required to define the resource portfolio. These are referred to as the option and build levels.

The option level governs the amount of resource for which options would be acquired and held in inventory. The build level governs the amount of resource moved out of inventory and into actual construction. The option and build levels represent levels within the range of load uncertainty to use as guides for making resource decisions.

A hypothetical example is shown in Figure 10–11. In this example, the region has moved out along a somewhat random load path and finds itself at load level l in time period t. The future load path is still unknown, and decisions must be made in the face of this uncertainty. To do this, a range forecast is first made from period t, and a probability distribution is applied to the forecast range. Note that the internal range forecast from this time period looking forward is likely to be completely different from the original detailed load forecasts used in the model. As a specific load path evolves, the forecasts change with it. This new forecast is referred to as the conditional load forecast because it is updated dynamically, depending on the observed load path. Within this conditional range forecast, further forecasts must be made to use as a guide in making option decisions and build decisions. The approach used here is to develop a median forecast for the new range and add or subtract constant energy amounts to develop the option and build forecasts. In this example, 1,500 average megawatts are added to the median forecast to generate the option forecast. The build level adjustment is zero, and the build forecast is identical to the median forecast. Once these forecasts have been made, the resource priorities, resource availabilities, and option and construction lead times are used to make resource decisions. Conservation acquisition and generating resource build decisions are guided by the build level forecast. Option decisions use the option level forecast as a target. The process is dynamic and repeats annually as the simulation moves through time.

The Council conducted a number of studies at various combinations of build and option levels to determine which combination would result in the lowest present value cost on an expected value basis. The results are shown in Figure 10–12. The solid line shows the system cost impact of holding the option level constant at 1,500 average megawatts and changing the build level from -1,500 to + 1,500 in increments of 500 average megawatts. The dashed line shows the cost impact of holding the build level constant at zero average megawatts and changing the option level in increments of 500 average megawatts. The graph illustrates that the strategy of making build decisions to a target of near load/resource balance, and at the same time carrying a sizable inventory of options produces the lowest system costs. This result makes intuitive sense because the option cost of the resources in the portfolio is much less than the cost of their actual construction.

Options can be thought of as a relatively cheap form of insurance that reduces resource lead time and allows the region to guard against unanticipated periods of rapid load growth. It appears cost-effective to build a significant inventory of options in order to assure flexibility in the resource acquisition process. However, because of the much higher costs associated with build decisions, they should be guided by using more conservative load-level targets, near the expected value of load, to produce the most cost-effective portfolio on an expected-value basis across the wide range of possible load outcomes.

Table 10-3
Resource Priority Order

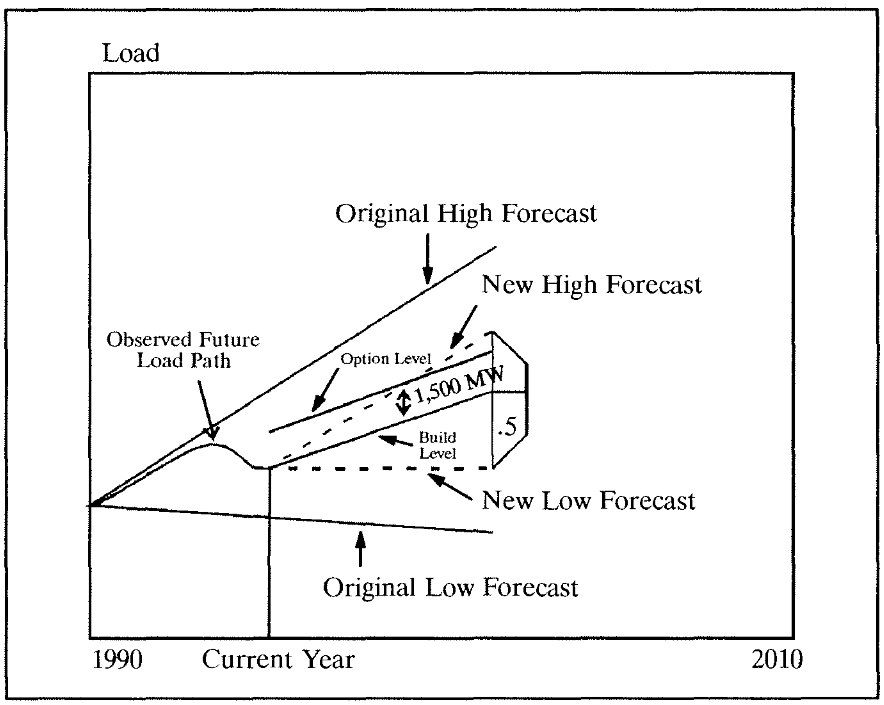
	Non-Discretionary Resources
	▪ Water Heat
	▪ New Commercial Model Conservation Standards
	▪ Commercial Renovations and Remodel
	▪ New Single-Family Residential Model Conservation Standards
	▪ New Manufactured Housing
	▪ New Multifamily Residential Model Conservation Standards
	▪ New Residential Lighting
	▪ Hot Water Heat Pumps
	Discretionary Resources
	▪ Conservation Voltage Regulation
	▪ Hydro Efficiency Improvements
	▪ Industrial (Block 1)
	▪ Irrigation
	▪ Transmission and Distribution Efficiency Improvements
	▪ Small Hydro 1
	▪ Industrial (Block 2)
	▪ Existing Commercial
	▪ Multifamily Residential Weatherization
	▪ Single-Family Residential Weatherization
	▪ Hydrofirming (Combined-Cycle 1)
	▪ Small Hydro 2
	▪ WNP-3
	▪ Thermal Plant Efficiency Improvements
	▪ Cogeneration 1 (Biomass Fueled)
	▪ Cogeneration 2
	▪ WNP-1
	▪ Hydrofirming (Combined-Cycle 2)
	▪ Municipal Solid Waste
	▪ Existing Residential Lighting
	▪ Cogeneration 3
	▪ Wind 1
	▪ Geothermal
	▪ Small Hydro 3
	▪ Eastern Montana Coal Gasification

Table 10-3 (cont.)
Resource Priority Order

Discretionary Resources (cont.)
▪ Cogeneration 4
▪ Eastern Washington Coal Gasification
▪ Expensive Conservation
▪ Eastern Oregon Coal Gasification
▪ Western Washington/Oregon Coal Gasification
▪ Nevada Coal Gasification
▪ Wind 2
▪ Small Hydro 4
▪ Biomass
▪ Wind 3

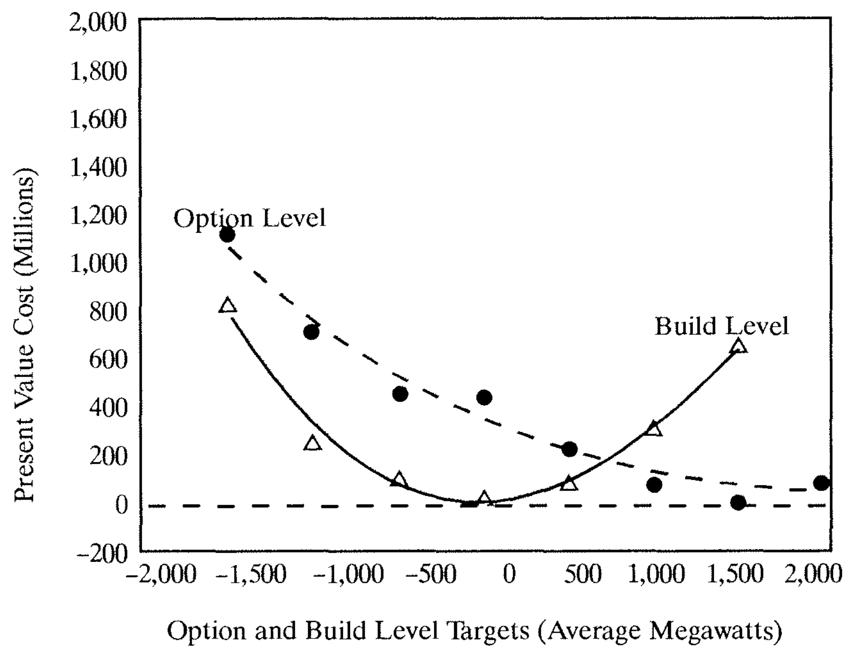
Option and Build Level

Figure 10-11
Option Decisions and Build Decisions are Made to Different Load Levels



Option and Build Level Studies

Figure 10–12
Build Resources to Load/Resource Balance but Carry a Surplus of Options



Conservation Acquisition Studies

One of the important elements of the Action Plan is the call for action on conservation programs, with specific targets for acquisition over the next 10 years. In the Council's early power plans, conservation was perceived to be a highly flexible resource that could be managed to easily adapt to load growth conditions. The experience of the last decade has shown, however, that conservation may not be quite so flexible. It takes time to ramp programs up and to develop an infrastructure capable of reliable delivery of energy savings. Frequent changes in funding levels, program design or acquisition targets can be disruptive to established utility programs and to the labor force involved in installation. Running a program as fast as possible until all savings have been exhausted, followed by a rapid program shutdown, is likely to cause economic dislocations. Reasonable stability in funding levels and personnel have been identified as an important component in conservation program management and delivery mechanisms.

The Council conducted a set of studies to find the level of static conservation actions for the 1990s that would produce the lowest system cost. The first step in the study was to determine the conservation acquisition schedules needed to meet load in each of the low, medium-low, medium, medium-high, and high load conditions. The development schedules for each of the discretionary programs from 1991 to 2000 were then tested as a forced component of the resource strategy. In these runs, full load uncertainty with 100 load paths was used. The discretionary program energy was a constant pattern over the first 10 years of each load path, regardless of need. If the forced schedule was one of the medium cases, and a load path turned out to be near the low, much more conservation than needed would be acquired. In high load conditions, less energy than was needed would be achieved. After 2000, the program management logic in the model takes control of the program. Program scheduling then begins to respond to need under each load path. Only the discretionary programs were forced in these studies; the non-discretionary program energy varied with economic conditions as usual.

Figures 10–13 and 10–14 display the results of these studies. Figure 10–13 displays the change in the mean present value system cost for each forced acquisition schedule tested. The base case here is one in which no discretionary program energy is allowed before 2000, and values shown are changes in system costs from this no-action alternative. The graph shows that benefits increase rapidly as program energy approaches the medium target. Benefits level off and decline slowly as the higher conditions are approached. Expected value benefits are maximized near the medium schedule at slightly over $1 billion.

Forced Conservation Studies

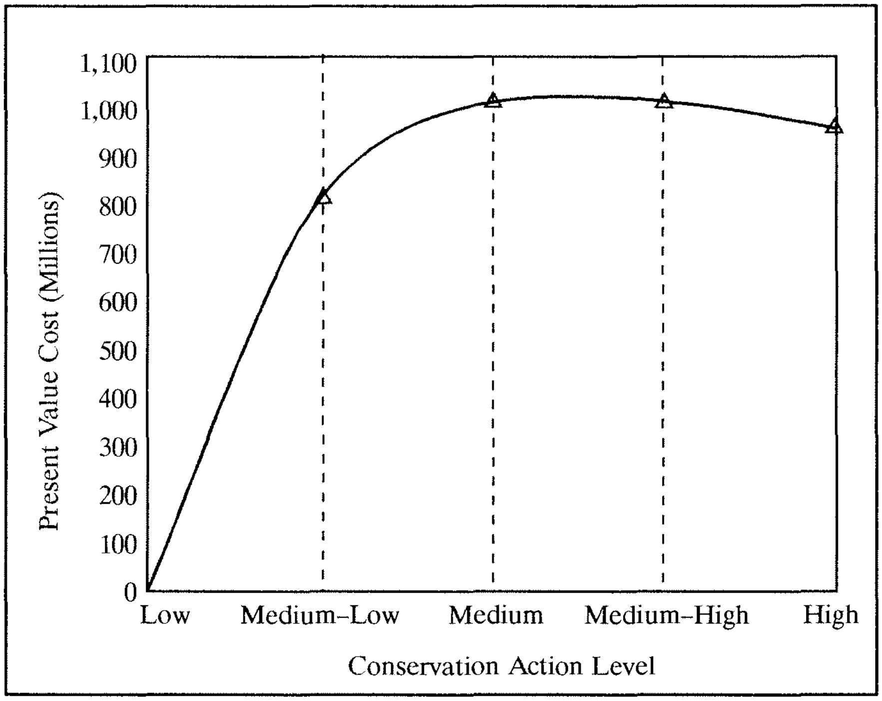


Figure 10-13
Aggressive Conservation Actions Show Large Benefits Over Low Activity Levels

Figure 10-14 is a plot of the differences in the five alternative forced conservation schedules against differences in their standard deviations. Changes in mean costs are plotted on the horizontal axis, while changes in the standard deviation of cost are plotted on the vertical axis. The standard deviation is a measure of the dispersion of the values in the system cost distribution, and is frequently used to describe the risk associated with an action. The medium action schedule is used here as the base case, and occurs at the zero value on each access. It represents the point of least cost, but it is not the point of least risk. Both the medium-high and high schedule have cost distributions with lower standard deviations than the medium. The medium-high schedule has a cost increase of about $10 million, with a reduction in standard deviation of about $150 million. The mean of the cost distribution is slightly higher, but the distribution of costs has significantly less dispersion. This occurs because the higher conservation levels under the medium-high schedule limit the exposure to high cost resources in high load conditions more than the medium schedule does. In the judgment of the Council, the slight cost penalty of going to the medium-high acquisition schedule is more than offset by the reduction in risk.

Figure 10-15 shows the breakdown of the medium-high discretionary conservation energy by program for both Bonneville and the investor-owned utilities. These are the levels that are in the Action Plan; they are used in resource schedules discussed below. Figure 10-16 shows the capital expenditures associated with the Action Plan conservation energy. These represent total costs to utilities and customers. The total expenditure between 1981 and 2000 is approximately $7 billion.

Alternative Resource Portfolios

No one would argue that the resource availabilities shown in Table 10-1, and used for the resource priority order, option/build level, and forced conservation studies just described, are known with a high degree of certainty. There is a large band of uncertainty about both future electric demand and also the resources that will be available to meet that demand. Load uncertainty is treated automatically in the computer modeling the Council performs for any portfolio analysis. Resource uncertainty in this plan is addressed through examining alternative scenarios for the long-term supply and cost of resources.

The public comment on the draft plan made it clear that Northwest citizens and organizations are concerned about three key issues when it comes to future electric resources. These include: a) the role of coal and nuclear plants in the region's energy future, b) the actual level of conservation savings that can be achieved, and c) the price and availability of future natural gas supplies. To address these issues, the Council has included not only a resource portfolio that assumes the diverse set of resources described by Table 10-1 is available, but also three other portfolios to address the major sources of resource uncertainty.

Conservation Risk Analysis

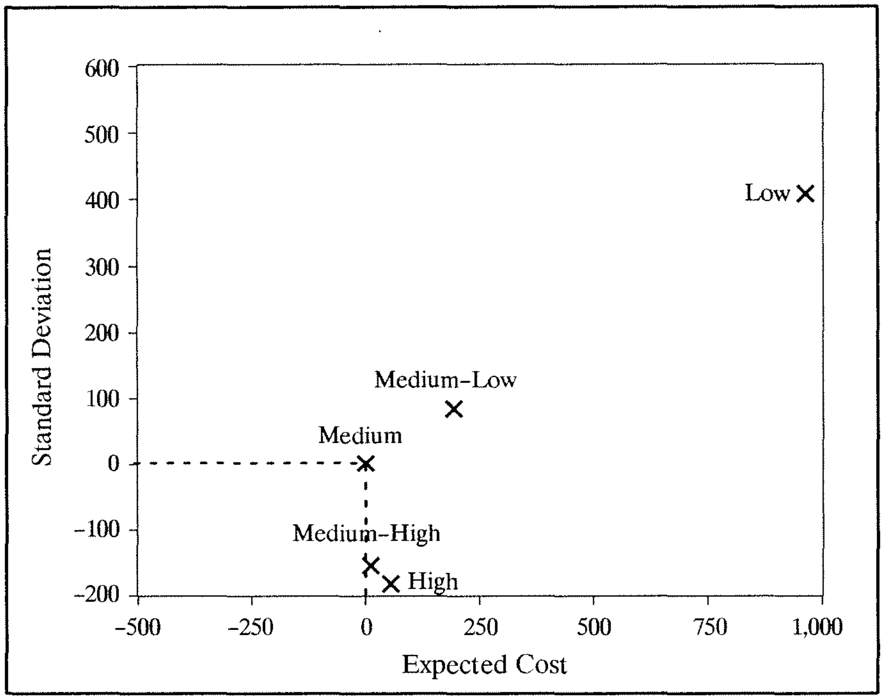
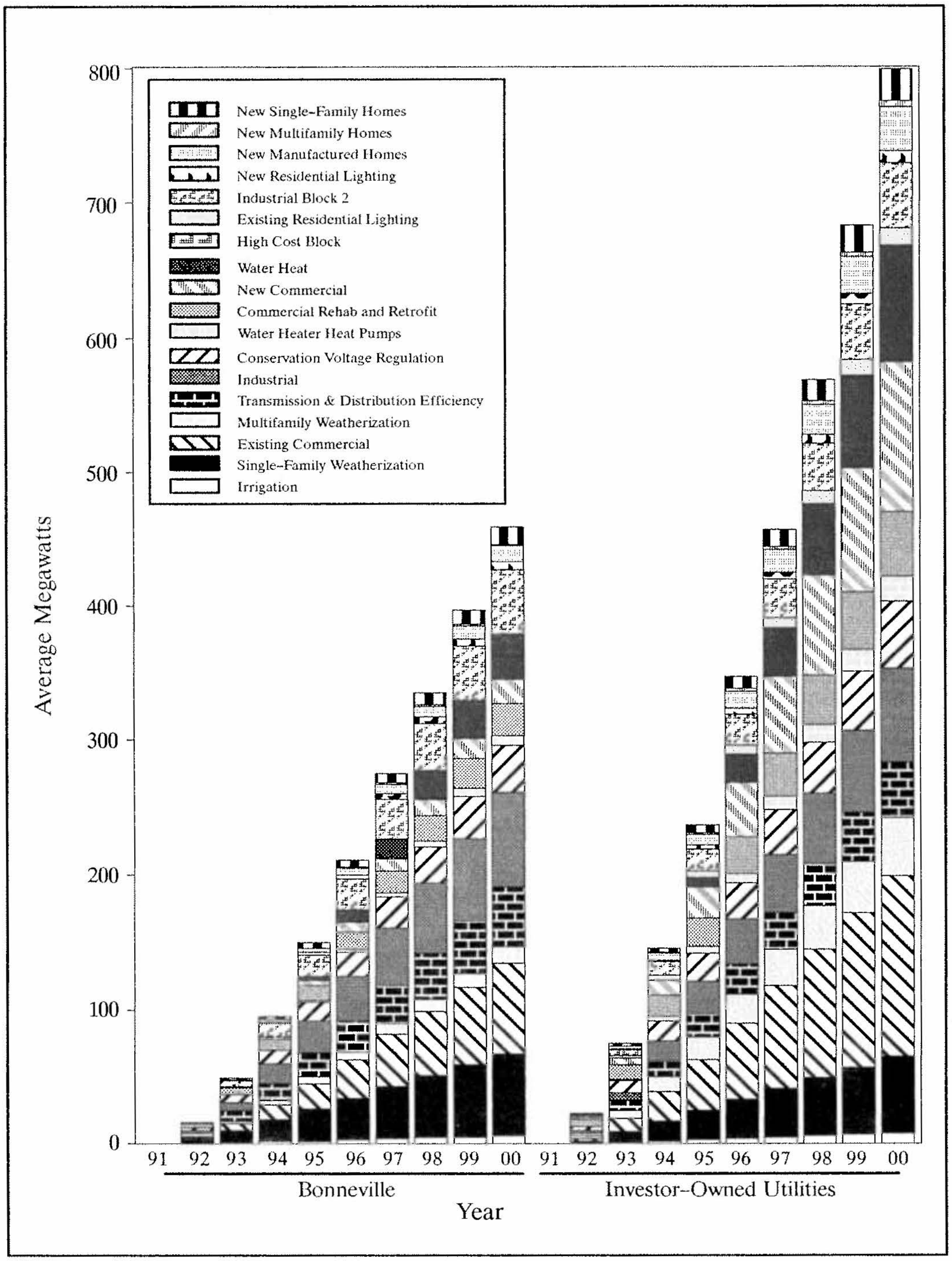


Figure 10–14
Moving from Medium to Medium–High Shows Significant Reduction in Risk for a Small Increase in Cost

Action Plan Targets

Figure 10-15
Discretionary
Conservation Energy



Efficiency Spending

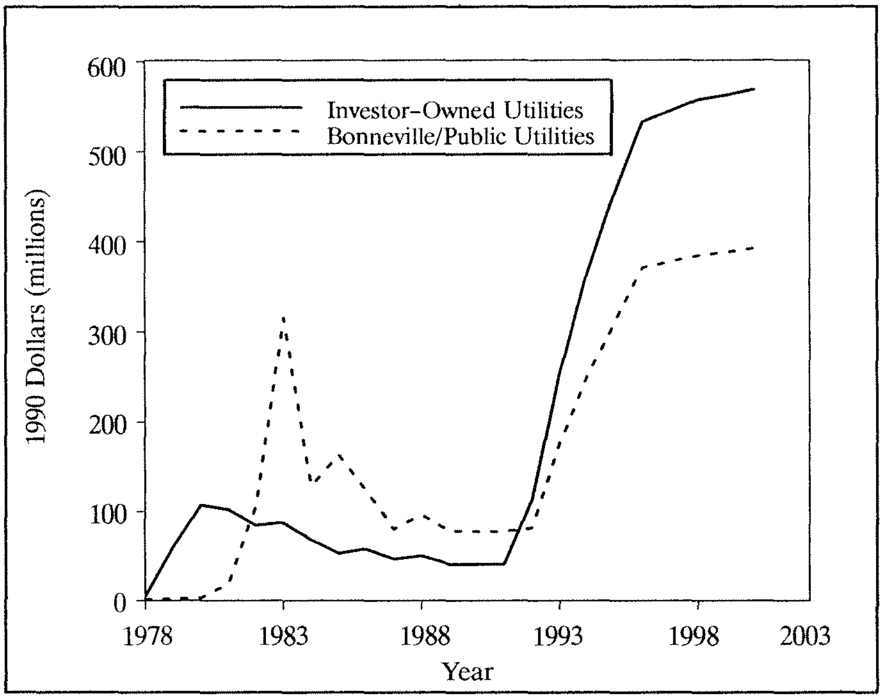


Figure 10-16
Expenditures by Consumers and Utilities Will Total About $7 Billion Between 1991 and 2000

By developing and testing a set of alternative resource portfolios, the Council was able to identify the most significant load and resource-related risks the region might face, and to compile the best set of actions to ensure an adequate and reliable power supply. Immediate actions that are common to several portfolios have the highest priority in the Action Plan.

The four portfolios described below all assume that the ability to forecast electrical loads is limited and treat the full spectrum of load uncertainty. The first portfolio assumes the diverse supply of resources summarized in Table 10-1 is available. The last three portfolios modify these assumptions to address specific resource concerns.

A resource portfolio is defined through the availability of resources, the priority order for resource development, the option and build decision rules, and a set of forced decisions independent of load path. For all four of the portfolios described below, the option target inventory was 1,500 megawatts, and the build level was a target of load/resource balance. The energy acquired for the discretionary conservation programs was forced across all load paths through the year 2000 at levels equal to that acquired under a medium-high load path. After 2000, the programs were managed as needed to maintain the build level target. The resource availabilities and priority orders were changed as appropriate for the alternative scenarios. Each portfolio uses the "split region" assumption. That is, Bonneville and the investor-owned utilities purchase new resources independently, and resource development is not coordinated at a regional level. Each study was run across 100 future load paths.

The data used to develop many of the resource portfolio graphics are in Appendix 10-B. Appendix 10-B has detailed information on the schedules for each conservation program and generating resource over the planning horizon for each of the alternative portfolios described here. The data for the averages of the 100 load path studies were used to develop the pie charts. The data from the single load path studies are the basis for the resource strata charts.

Portfolio 1: Diverse Resource Supply

(This portfolio is referred to as "Load Uncertainty" in Volume I.)

The question addressed by this portfolio is how the Northwest could most economically respond to uncertainty about future electricity use. To answer that question, the Council looked at a diverse array of resources, assuming that the predicted costs and availability listed in Table 10-1 are accurate. This portfolio uses the resource priority order described in Table 10-3. This strategy is the least expensive of the four portfolios examined in the final plan.

The resources acquired by the region under this portfolio are illustrated in Figure 10-17. These pie charts are aggregated into the region as a whole by including the combined actions of Bonneville and the investor-owned utilities. The resource categories shown generally follow the priority in the Act, with cogeneration and hydrofirming treated as high efficiency resources and large thermal broken down into coal and nuclear. The renewable category includes biomass fueled cogeneration. The pie charts display the average energy contributions to the system by the various categories of resources in 2000 and 2010. The values shown here are the averages of resource energy in the portfolio over 100 different load scenarios. In some cases, the energy contribution of a particular resource is needed in only a few of these load scenarios. In these portfolios, the expected or average energy contribution can be thought of as the energy output or savings of the resource multiplied by the frequency of its occurrence in all the load paths modeled. For example, if a 100-megawatt resource is needed in 40 percent of the load scenarios, it contributes 40 megawatts to the expected energy. Data for the pie charts in this section are included in detail in Appendix 10-B.

In this diverse supply portfolio, conservation is the dominant resource in 2000. Conservation contributes almost 1,400 megawatts or a little more than half of the new resource additions. Strategies to back up the hydropower system—known as "hydrofirming resources"—are the second largest resource group. They are expected to make up 23 percent of the resource mix. Renewable resources, such as new hydropower, geothermal, biomass-fired cogeneration and wind are expected to make up 16 percent of the total. Finally, gas-fired cogeneration completes the expected resource additions by the year 2000 with 9 percent of the overall resource mix.

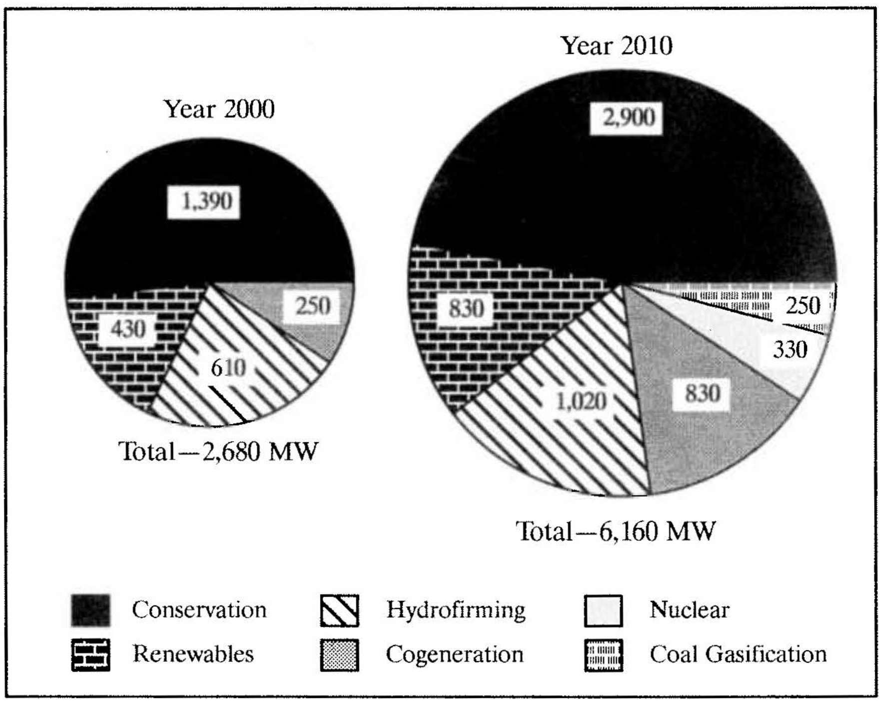
By 2010, this resource portfolio has the same basic mix, but much more of each resource is likely to be needed. Conservation is still expected to dominate resource additions by providing 2,900 megawatts. Renewables and hydrofirming resources are expected to supply 30 percent of the total. Cogeneration is expected to add about the same amount as renewables or about 14 percent. Relatively small contributions are expected from coal gasification plants and nuclear power plants, which together make up less than 10 percent of the expected mix in 2010.

Figures 10-18 and 10-19 show more detailed information about this portfolio. These resource strata charts show the separate resource development paths followed by Bonneville and the investor-owned utilities in each of the four deterministic load forecasts. The resource categories are less aggregated than in the regional pie charts, using homogenous resource types like small hydro and geothermal instead of the priorities in the Act. These charts illustrate resources developed under single load paths, as opposed to the averages over 100 load paths shown in the pie charts.

These schedules are illustrative only. It is unlikely that any of these acquisition schedules will actually occur, because the likelihood any individual load path will occur is extremely small. As discussed earlier, in the estimation of the Council, load occurrences between the medium-low and medium-high are the most likely. The probability is

Portfolio 1: Diverse Resource Supply

Figure 10-17
Diverse Least-Cost Resources to Manage Load Uncertainty



extremely low that future load conditions approximating either the high or low load conditions will materialize. These charts also make the assumption that planning can be done with perfect knowledge of future load conditions and that resources can be matched quite closely with load regardless of their lead time. These figures are included to illustrate the wide range of potential resource development faced by the region's utilities.

The range of system costs associated with this portfolio is shown in Figure 10-20. This figure is a frequency distribution for the present value of system costs over 100 load paths. System costs estimated here by the Council include operating and maintenance costs of all existing resources, plus the costs of all resources added to the existing power system over the next 20 years. Resources needed to replace existing resources at the end of their useful lives also are included to properly account for the effects of building resources with differing physical lives. All costs are accumulated for the next 60 years and converted to present values.

This portfolio shows a wide range of potential cost outcomes. If low load growth occurs and the region sees generally favorable water conditions, system costs may be as low as $10 billion. On the other hand, high load conditions in conjunction with poor hydro conditions could lead to cost outcomes exceeding $90 billion. This distribution has a mean cost of approximately $47 billion. It is the least expensive of the four portfolios described here.

From analysis of this portfolio, the Council made several observations. First, in both the high and medium-high scenarios, there will be large energy deficits until after 2000. Even assuming the region acts as fast as possible, it is difficult to add significant amounts of new resources by the mid-1990s. In fact, if load continues to grow at a rate faster than 1 percent per year, new resources will not be able to keep up with load growth during the 1990s.

A second observation is the importance of beginning to acquire all cost-effective efficiency improvements as soon as possible. Conservation programs take time to design, staff and operate. If significant savings are going to be secured by 2000, the region needs to begin programs in every sector of the economy.

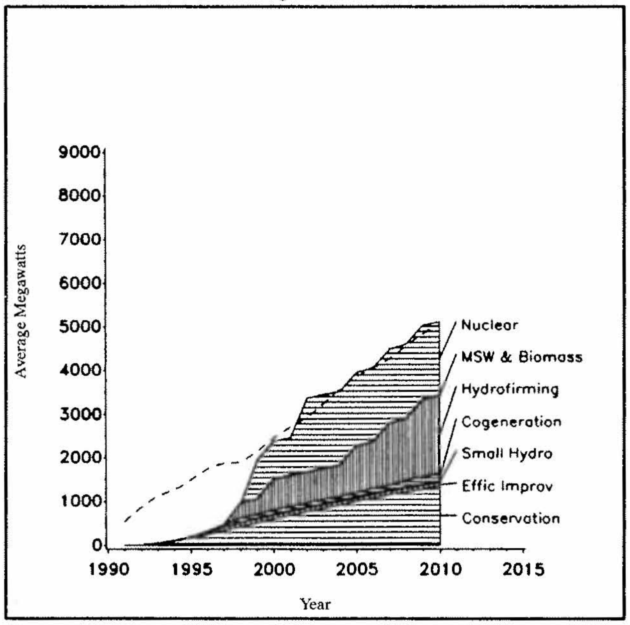
Lower cost renewables and cogeneration resources are probably going to be needed by 2000, too, and the region should begin acquiring these. Hydrofirming resources, higher cost renewables and cogeneration resources should be sited, licensed and designed, so the region can move quickly to acquire these resources if loads accelerate.

Finally, efforts to determine the cost and availability of geothermal, wind, solar and the two partially completed nuclear power plants could clarify the region's resource alternatives in the next power plan.

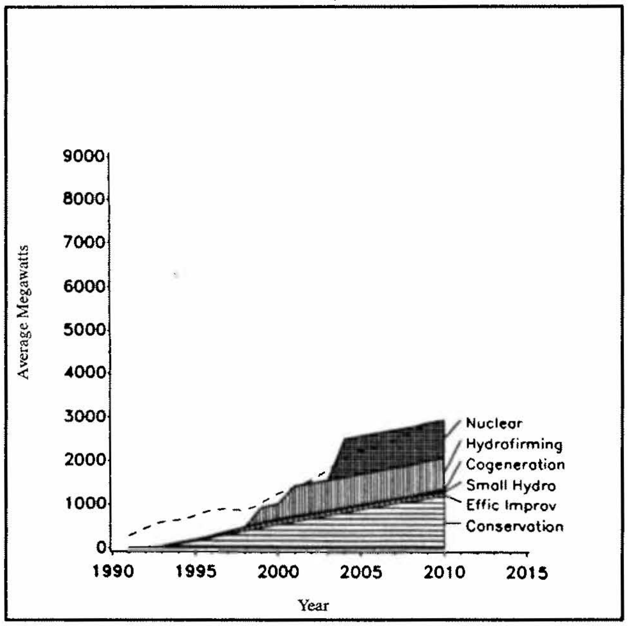
Diverse Resource Supply

Figure 10-18
Bonneville/Public Utility
Deterministic Resource Schedules

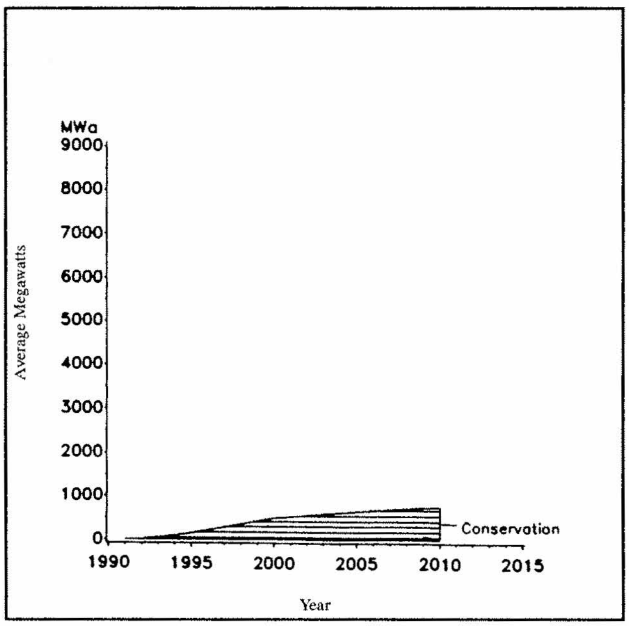
High Loads



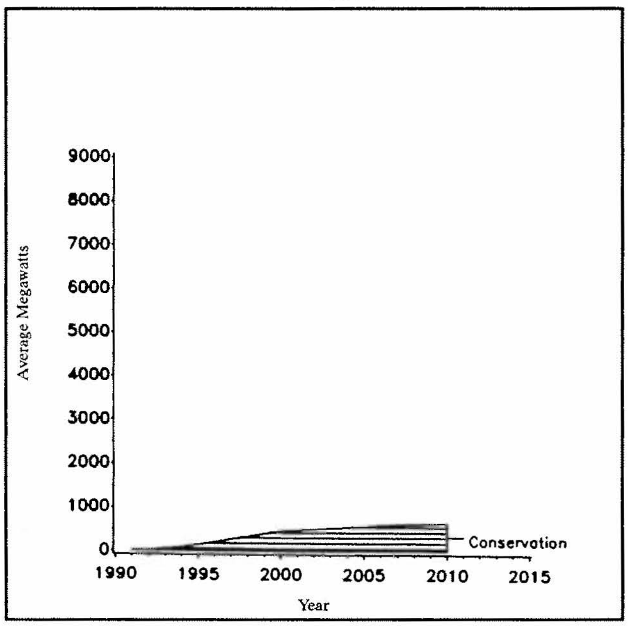
Medium-High Loads



Medium-Low Loads

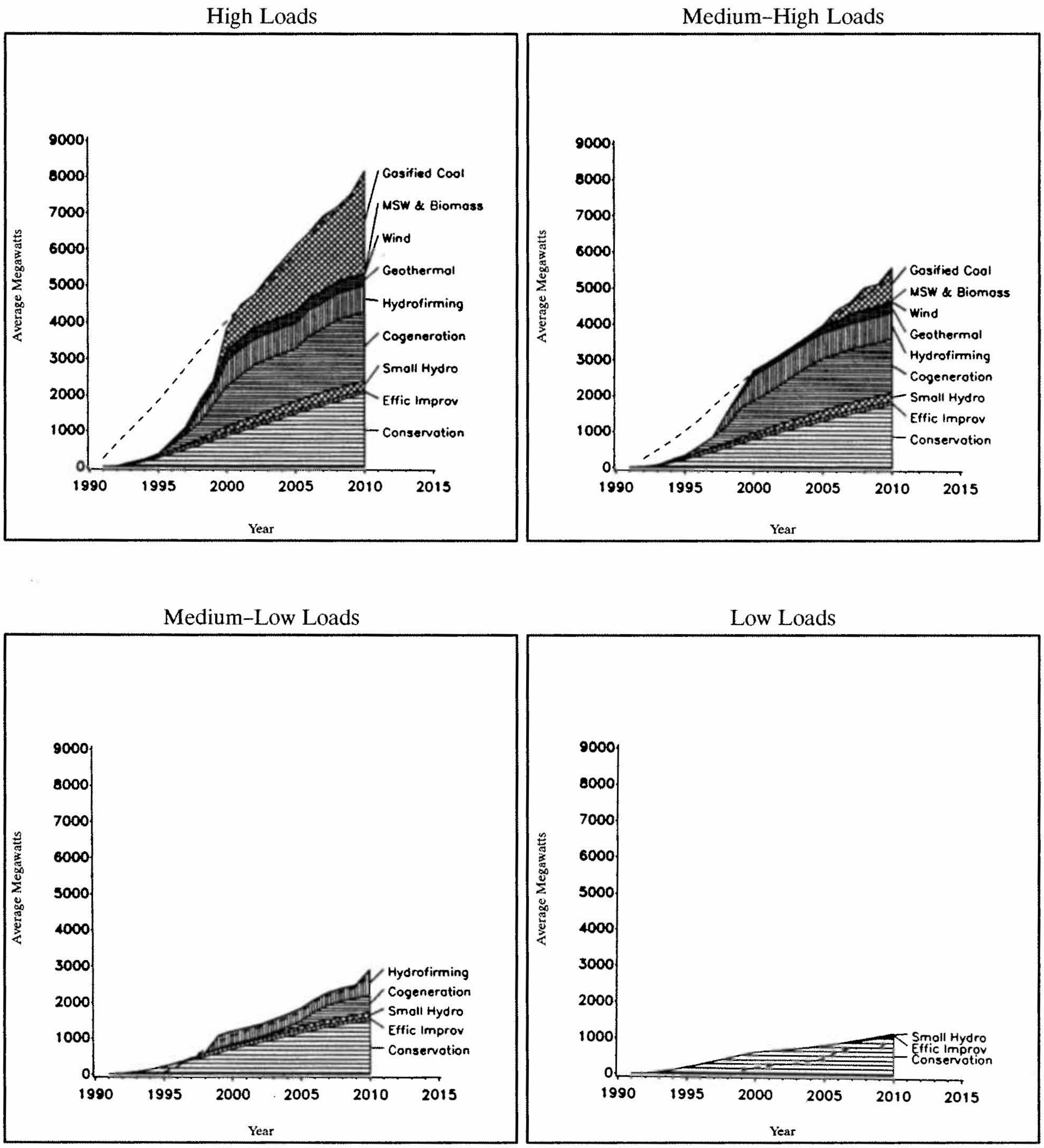


Low Loads



Diverse Resource Supply

Figure 10–19
Private Utility Deterministic Resource Schedules



Range of Costs

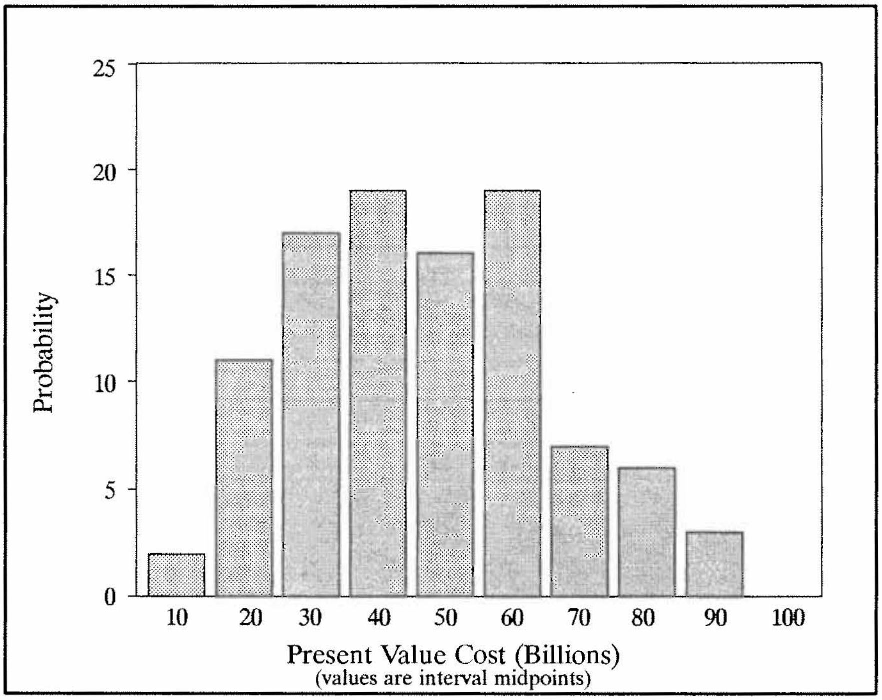


Figure 10-20
There is a Large Range of Uncertainty in System Costs

Portfolio 2: Nuclear and Coal Plants are Unavailable or Unacceptable

There has been much discussion of the unique uncertainties regarding both nuclear and coal-fired generating resources. This portfolio asks the question, can the Northwest's electrical energy requirements be met without turning to coal or nuclear plants?

To evaluate how the region could most cost-effectively respond in an energy future without nuclear or coal-fired power plants, the Council developed a resource portfolio that excluded them. This portfolio's average resource mix is shown in Figure 10-21. It relies on conservation, renewables, cogeneration and strategies to back up the region's existing hydropower system.

This second portfolio closely resembles the first, for the first portion of the planning period—up to the year 2000. In this portfolio, efficiency improvements continue to dominate the expected resource additions by the year 2000. The rest of the resource mix in 2000 is made up of renewables, hydrofirming strategies and cogeneration.

By 2010, conservation still is about half of the total mix. Renewables, hydrofirming strategies and cogeneration provide approximately equal shares of the resources that replace nuclear and coal gasification plants.

Figures 10-22 and 10-23 show the resource development schedules for the four deterministic forecasts for both Bonneville and the investor-owned utilities. The most striking feature of these charts is the inability of both groups to maintain load/resource balance under high load conditions in the 2000 to 2010 time frame. Both groups have sufficient resources through the medium-high load scenario. The lack of coal and nuclear is made up for by increased development of high cost renewables and cogeneration. However, under high load conditions, there are not enough resources available to meet load. The regional deficit grows to almost 3,200 average megawatts by 2010.

The cost impacts of this portfolio are displayed in Figure 10-24. These graphs portray the differences in cost between this portfolio and the diverse supply portfolio. The top portion of Figure 10-24 is a scatter diagram of cost changes versus regional load level. It shows that, unless regional loads at the end of the planning horizon exceed 26,000 average megawatts, the cost impacts of not having coal or nuclear available are likely to be small or negative.[4] However, once loads begin to exceed medium-high conditions, the cost impacts rise rapidly. In the higher load conditions, the cost penalties run from about $7 billion to $9 billion. The lower half of this figure is a frequency distribution for the same cost impacts. This distribution has a mean of $670 million.

4. The series of cost differences of approximately -$100 million are due to the exclusion of the preservation costs of WNP-1 and WNP-3, which were included in the diverse supply portfolio but are left out of this one because the plants are considered terminated. This second portfolio also excludes costs for the termination of WNP-1 and WNP-3 and therefore probably underestimates the cost of this portfolio. Termination costs are excluded from this analysis due to their high range of uncertainty. Any preservation and termination costs incurred by the region will increase the cost of this scenario across the board.

Portfolio 2: Nuclear and Coal Uncertainty

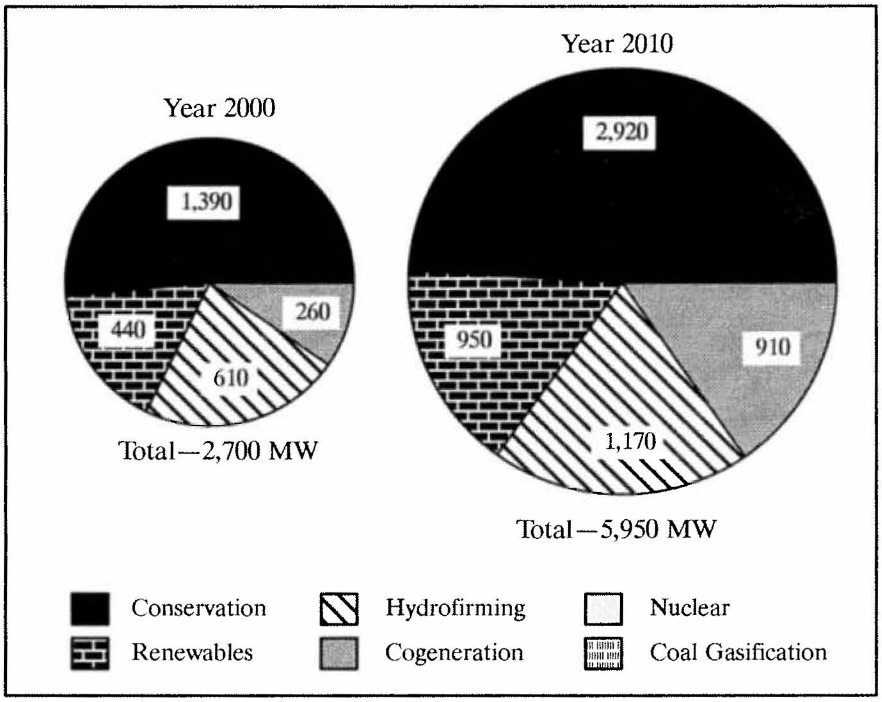
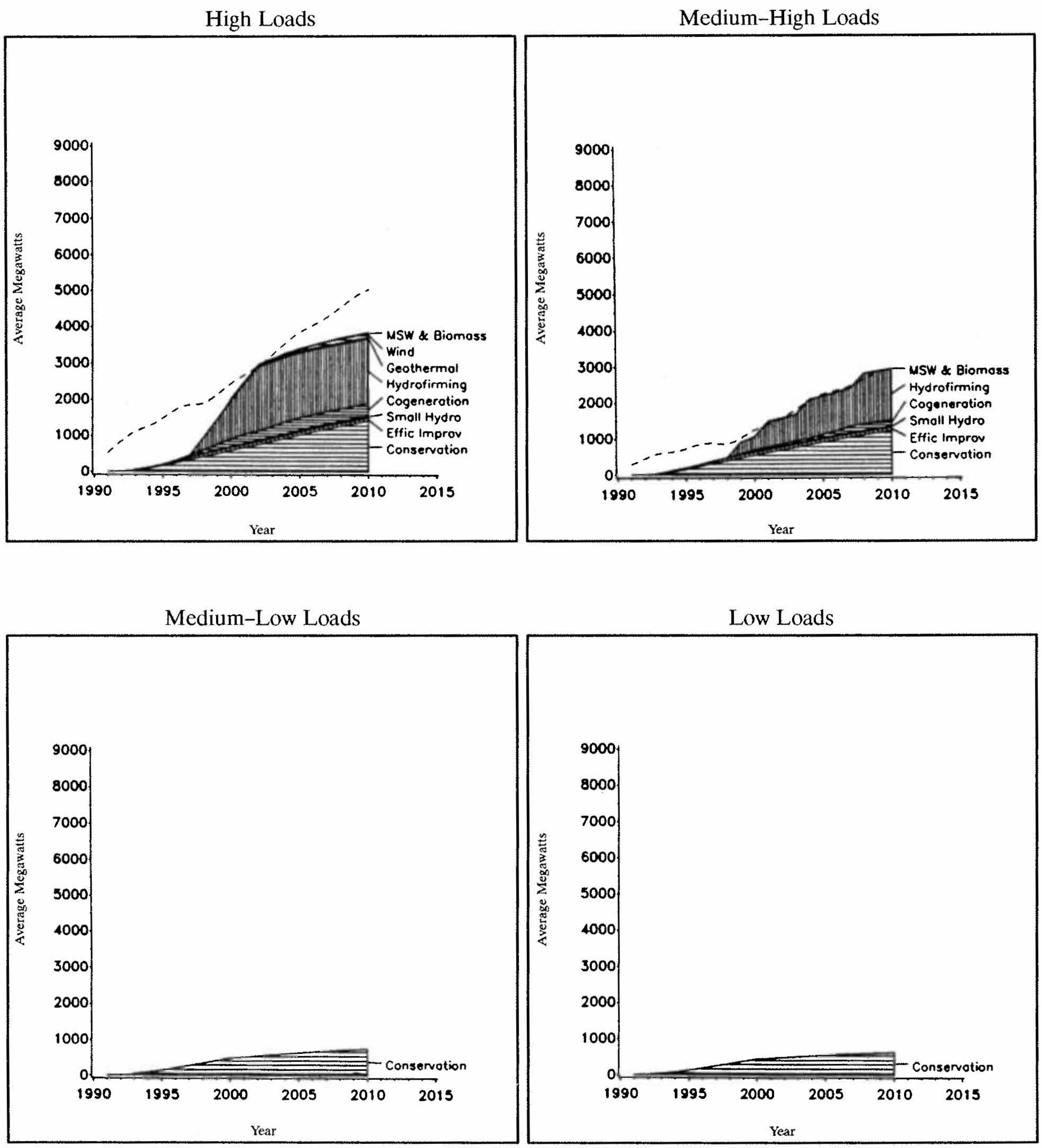


Figure 10–21
Expected Resource Mix if Large Thermal Resources are Either Unavailable or Unacceptable

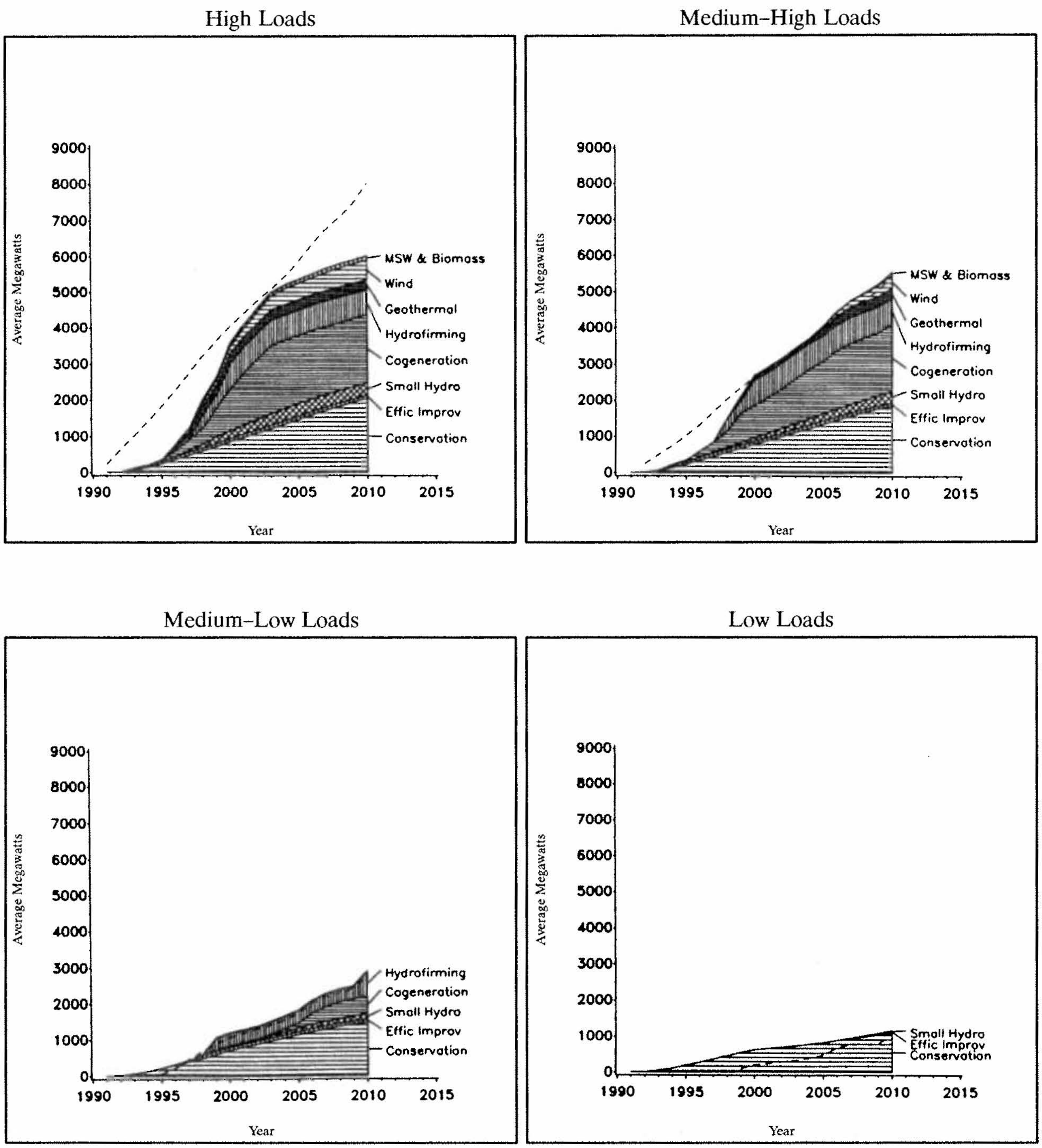
No Coal or Nuclear

Figure 10-22
Bonneville/Public Utility
Deterministic Resource Schedules



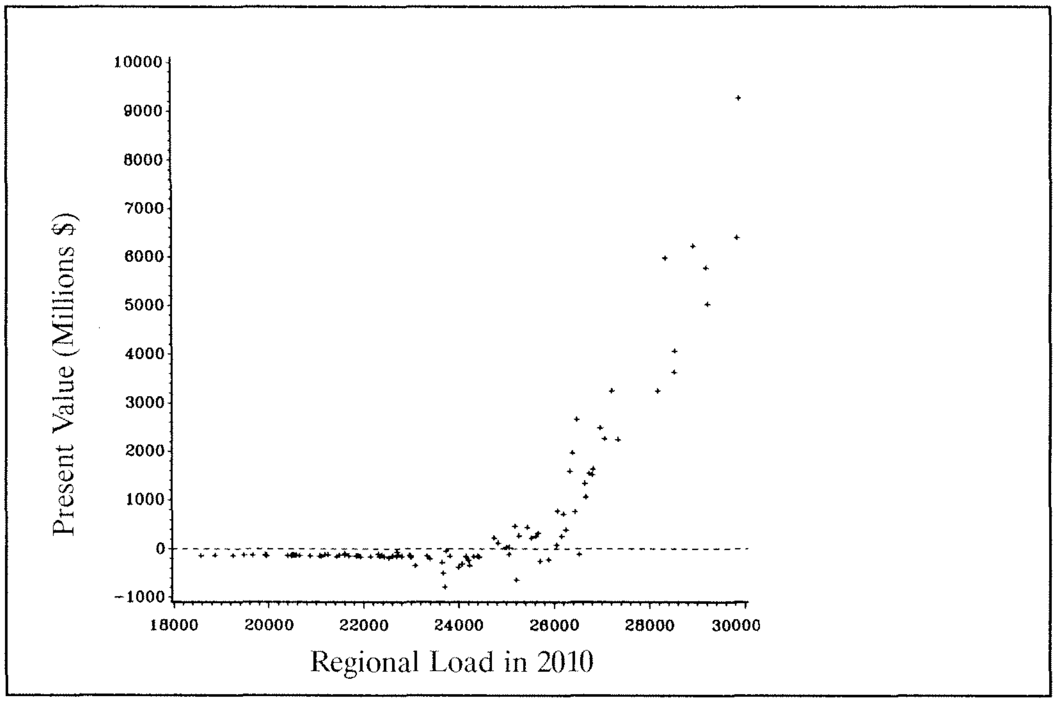
No Coal or Nuclear

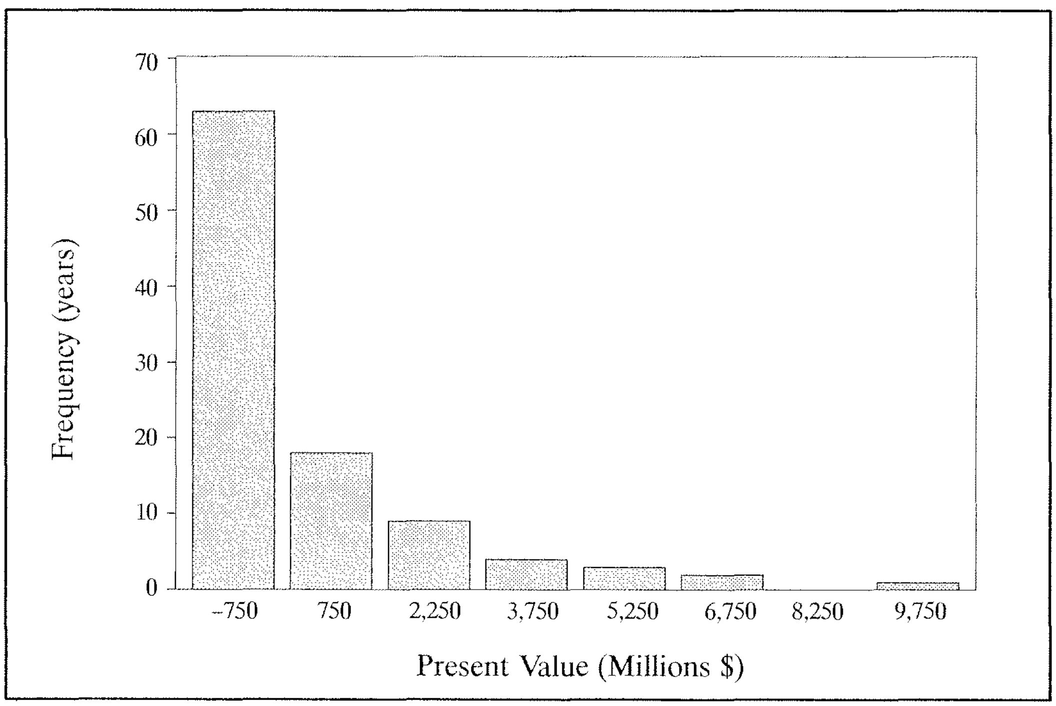
Figure 10-23
Private Utility Deterministic Resource Schedules



Cost Impacts of Removing Coal and Nuclear

Figure 10-24
Cost Impacts Occur in the Upper Portion of the Load Range





It is clear that to prepare for an energy future without either nuclear or coal plants, the region must begin to rapidly secure all cost-effective energy savings and expand the amount of this resource through additional conservation research and development. Research and development work is also needed on renewable technologies, such as geothermal, wind and solar. These technologies could provide large amounts of additional energy if they are found to be environmentally and economically feasible.

Finally, if coal and nuclear power plants are not available, the region is likely to need to turn to large amounts of gas-fired electrical generation. Gas-fired generation in this portfolio is almost equally split between cogeneration and gas-fired combustion turbines used to back up the hydropower system.

Portfolio 3: Less Conservation Achievable

This plan is based on the premise that energy conservation is the region's most affordable and reliable new source of electricity. There was clear indication throughout the draft plan public review process that that belief is widely held in the Northwest. But what happens to the Northwest's energy future if the region falls short of the aggressive conservation goals in this plan? Conservation may be the region's highest priority resource, but it is still an uncertain one.

Some suggest that the Council's target of achieving 85 percent of the technical conservation potential is overly optimistic. Bonneville and some utilities have argued that 60 percent is a much more reasonable expectation, especially in the existing commercial sector.

This third portfolio examines the risk posed if the region is unable to achieve the conservation in this plan. In this portfolio, it is assumed that only 60 percent of the total technical conservation potential in all sectors is achievable by the year 2010. If only 60 percent of the total conservation potential is achievable instead of 85 percent, the current target for the region of 1,500 megawatts by the year 2000 is reduced to 1,100 megawatts. The reduction from 85-percent penetration to 60-percent penetration cuts the expected energy savings that the region can achieve by 2010 under high load cases from 3,400 megawatts to 2,400 megawatts.

With less conservation, the region must add more generating resources. Figure 10-25 shows the expected resource mix changes in this third portfolio. Renewable resources and hydrofirming strategies are the predominant replacements, representing almost 50 percent of the total mix by 2000.

By 2010, conservation's share is reduced from about 50 percent to 35 percent of the total resource mix. Renewable resources and hydrofirming strategies increase slightly. Increases in the expected contribution of cogeneration, coal gasification and nuclear make up for most of the reduction in conservation.

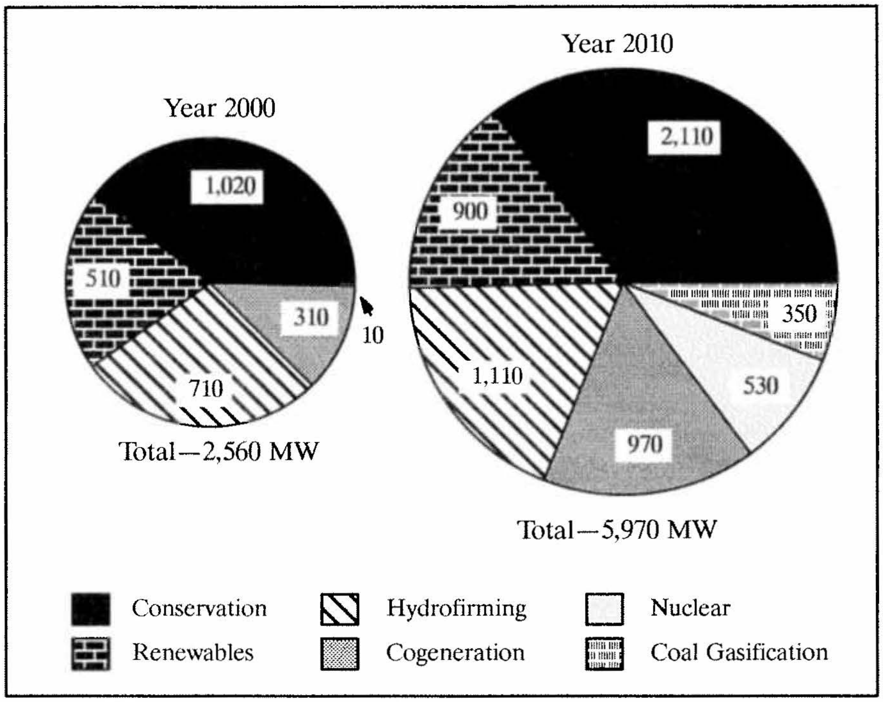
The resource development schedules for the public and private utilities under this portfolio are shown in Figures 10-26 and 10-27. The loss of conservation savings happens gradually over the next 20 years, and compared to the diverse supply portfolio, resources move forward across the entire load range to replace the loss of conservation savings.

The costs of failing to achieve the plan's conservation targets will not be small. The cost impacts associated with this portfolio are shown in Figure 10-28. This portfolio increases the expected costs over the diverse supply portfolio by $2.3 billion—the largest average increase of the three alternatives. Cost increases are seen across the full spectrum of load futures and range from about $900 million in the lower load conditions to almost $4 billion in higher load cases.

This portfolio illustrates the need to have a diverse resource mix. Depending on the level of future load growth, cogeneration, coal gasification, nuclear, and renewable resources could all play a role in responding to reduced conservation savings. Geothermal and wind resources could provide large amounts of cost-effective energy in the future, but the region lacks specific understanding of their costs and availability. Confirming these resources now could provide insurance against uncertainty about conservation's viability.

Portfolio 3: Conservation Uncertainty

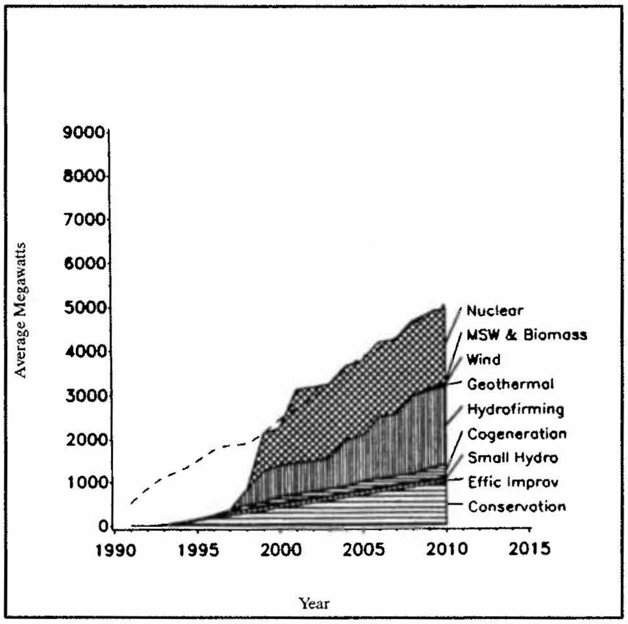
Figure 10–25
Expected Resource Mix if Conservation Programs are Less Effective



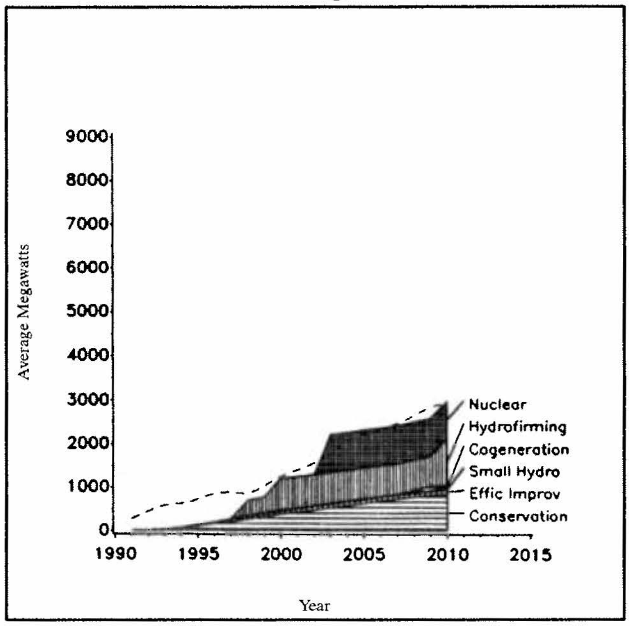
Less Conservation Achievable

Figure 10-26
Bonneville/Public Utility
Deterministic Resource Schedules

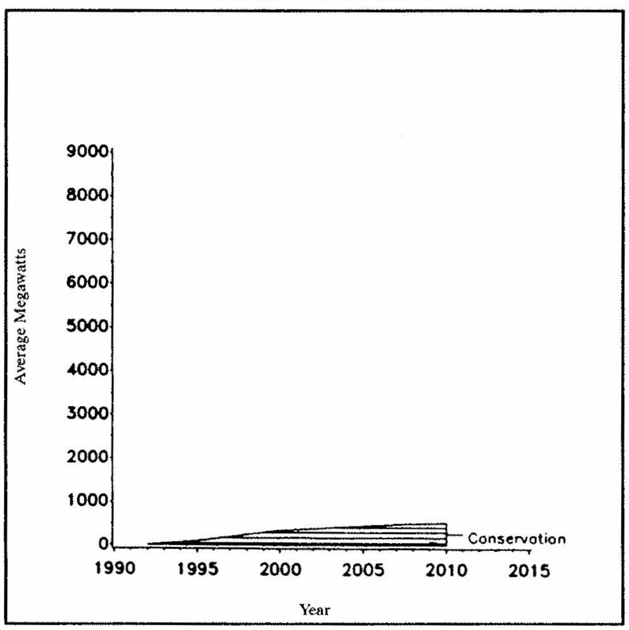
High Loads



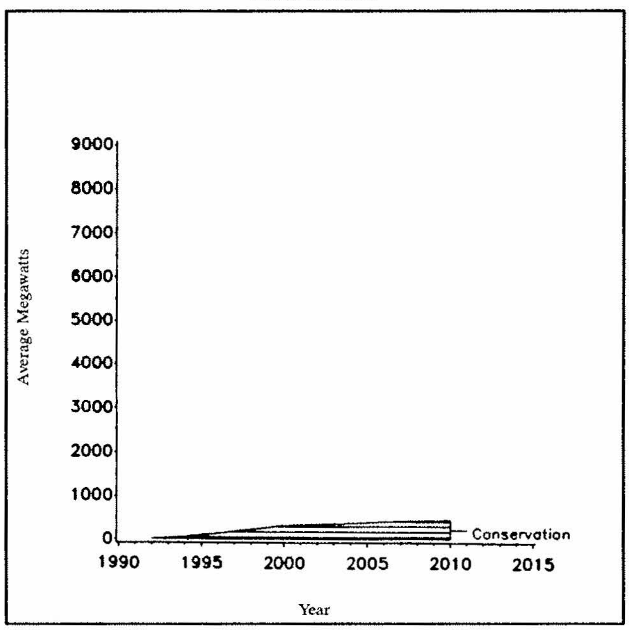
Medium-High Loads



Medium-Low Loads

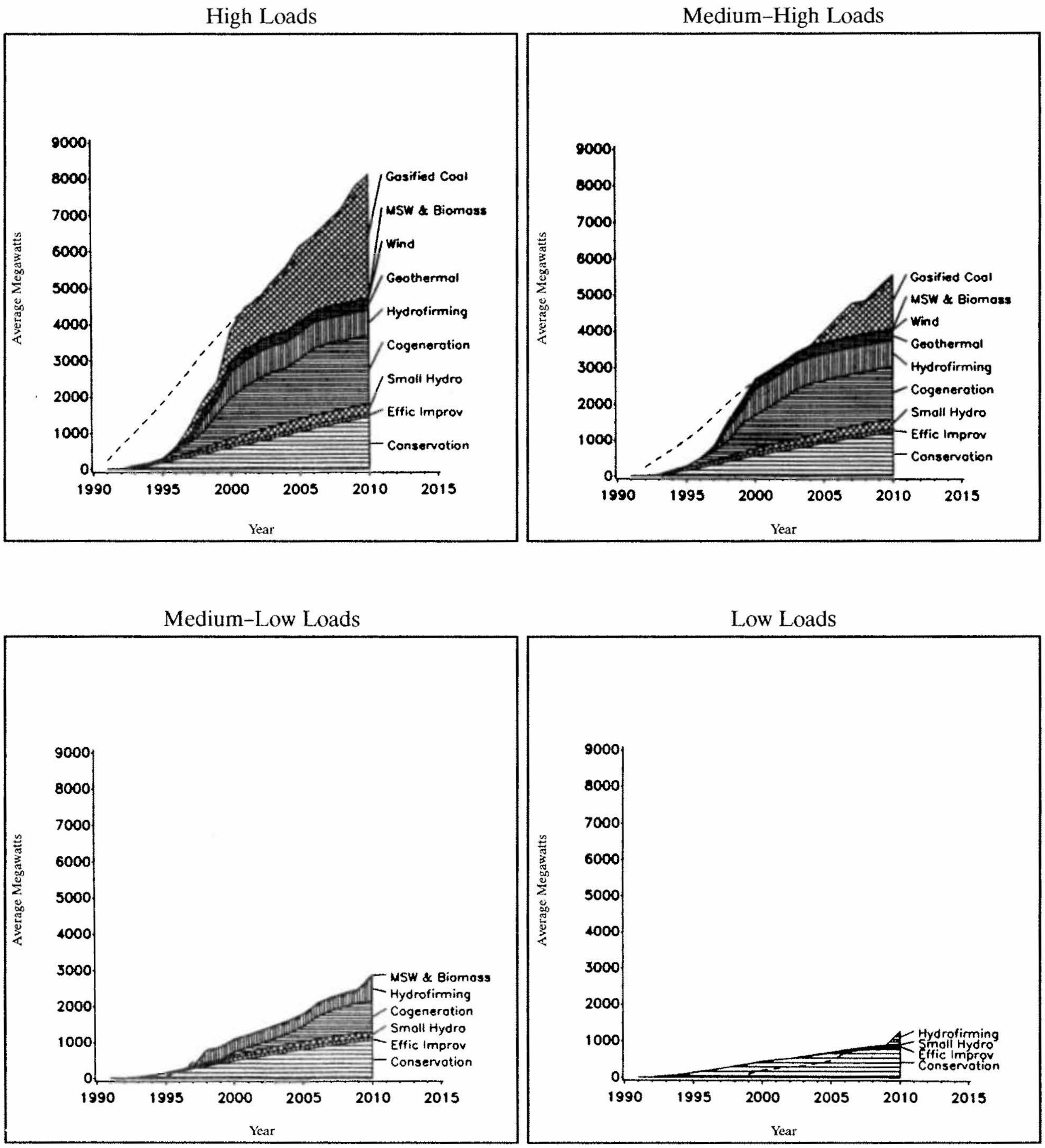


Low Loads



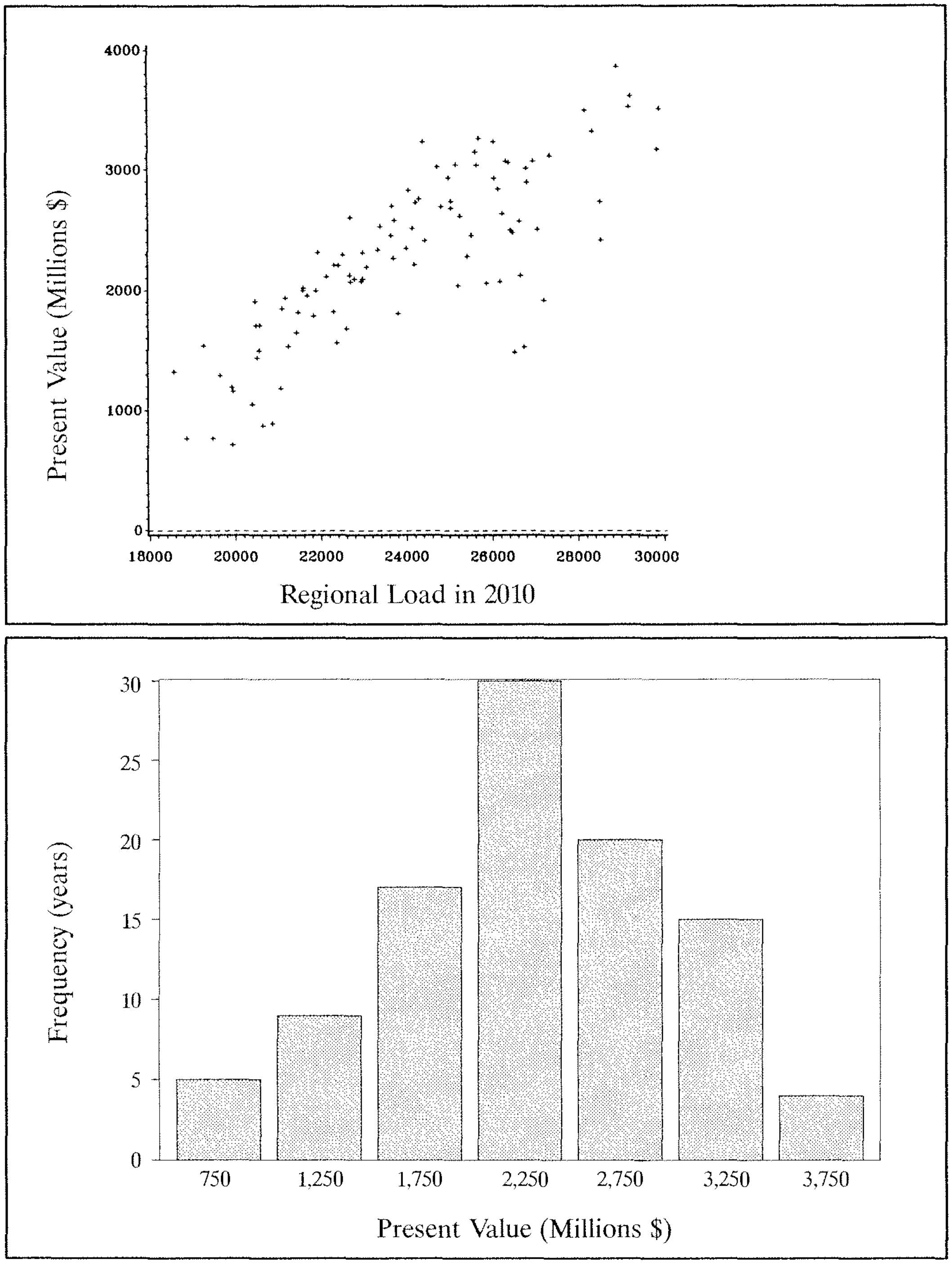
Less Conservation Achievable

Figure 10-27
Private Utility Deterministic Resource Schedules



Cost Impacts of Less Conservation Achievable

Figure 10-28
Cost Impacts are Significant Across the Entire Load Range



Portfolio 4: Natural Gas Uncertainty

The first three portfolios bank heavily on natural gas-fired technologies. The Council estimated that more than 1,700 megawatts, primarily gas-fired cogeneration, could be developed in the region for less than 15 cents per kilowatt-hour. In addition, the Council estimated that about 2,500 megawatts of hydrofirming strategies could be developed cost-effectively, utilizing gas-fired combustion turbines.

During the 1980s, there were abundant supplies of natural gas at low prices, but only a decade earlier price and availability of natural gas were problems. The shift to natural gas that is occurring in the electric power industry, as well as in other industrial sectors and among residential consumers, could once again cause significant price increases for this fuel. For this reason, a heavy dependence on gas-fired electric power generation may bring particular risks to the region.

This portfolio evaluates this particular source of uncertainty and explores the resources the region could turn to if the cost of natural gas rises to the Council's highest forecast price. The hydrofirming strategies and the gas-fired cogeneration blocks become more expensive under these assumptions and are pushed further down the resource priority list. The hydrofirming strategies become more expensive than WNP-1 and WNP-3, and the gas-fired cogeneration blocks become more expensive than gasified coal.

Figure 10-29 illustrates the average resource mix for this strategy to reduce the the risk of rapid gas price increases. This portfolio turns to renewable resources instead of cogeneration and gas-fired hydrofirming strategies. Conservation continues to play a significant and crucial role in the region's portfolio, providing more than 50 percent of expected resource additions by 2000. Coal gasification and nuclear power have slightly higher contributions to help reduce the region's reliance on gas-fired technologies.

By 2010, much of the cogeneration and hydrofirming strategies are replaced by renewables, coal gasification and nuclear. Conservation maintains its role as the biggest contributor to the region's expected resource additions.

However, in the higher load conditions, there are insufficient conservation and renewable resources to replace the cogeneration and hydrofirming strategies that are no longer cost-effective with higher gas prices. (See Figures 10-30 and 10-31.) Under medium-high load conditions, the investor-owned utilities' plans to build combined-cycle coal gasification plants must be accelerated so that the first plants are operating in 1997. Bonneville and the public utilities could need one of Washington's nuclear projects by 1999, if loads are growing at the medium-high rate of 1.7 percent.

This portfolio increases expected costs by $950 million, when compared to the first portfolio, but the cost impacts in higher load growth scenarios could be more than $3.2 billion. (See Figure 10-32.) Cost impacts are particularly difficult to estimate in this portfolio because increased gas prices also affect the market for Northwest power in California and will probably result in changes in California's resource mix. The cost and effect of this impact has not been included here.

Given the cost exposure inherent in an overdependence on natural gas as a fuel, this portfolio shows the need to secure the capability to switch to coal gasification from hydrofirming strategies that are gas-fired. Furthermore, the viability of WNP-1 and WNP-3 needs to be determined, so decisions to construct or terminate them can be made in future power plans.

Portfolio 4: Natural Gas Uncertainty

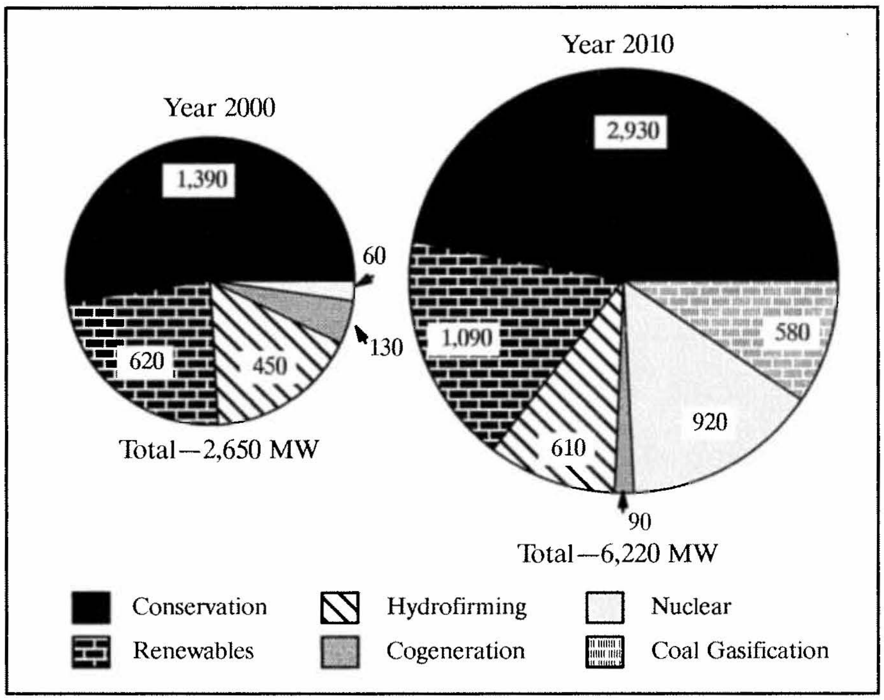
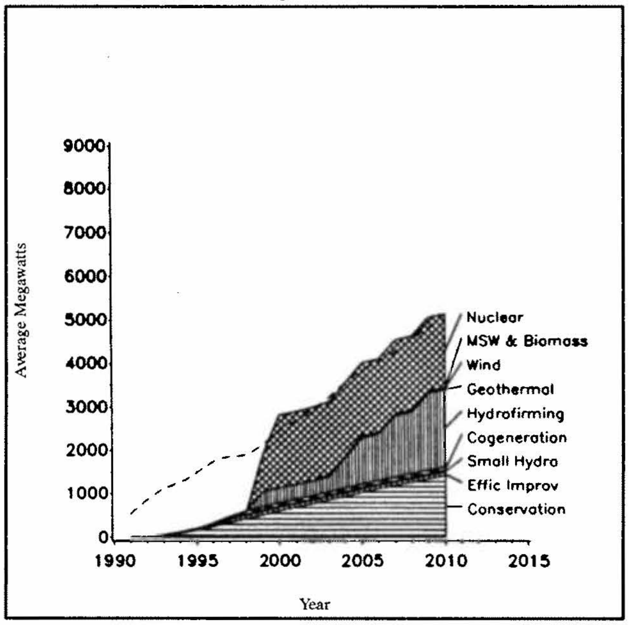


Figure 10-29
Expected Resource Mix if Natural Gas Prices Increase Rapidly

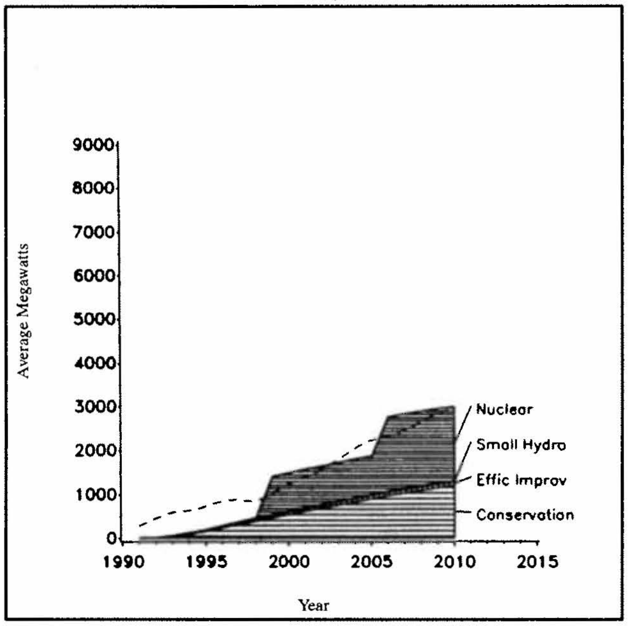
High Natural Gas Prices

Figure 10-30
Bonneville/Public Utility
Deterministic Resource Schedules

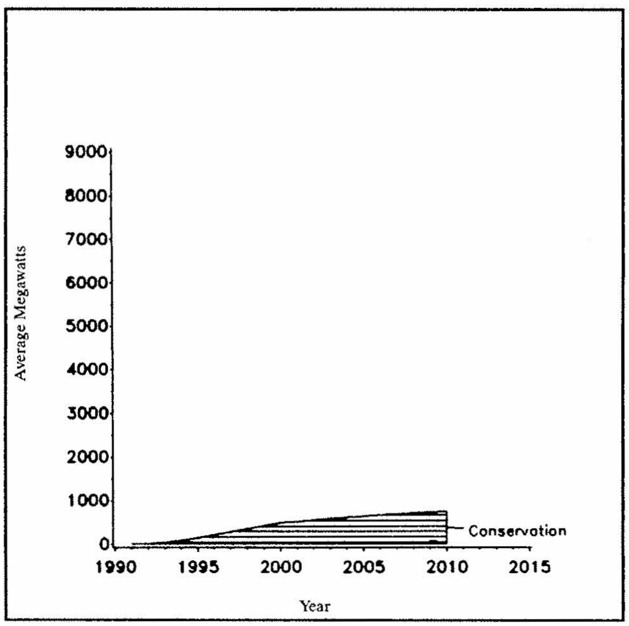
High Loads



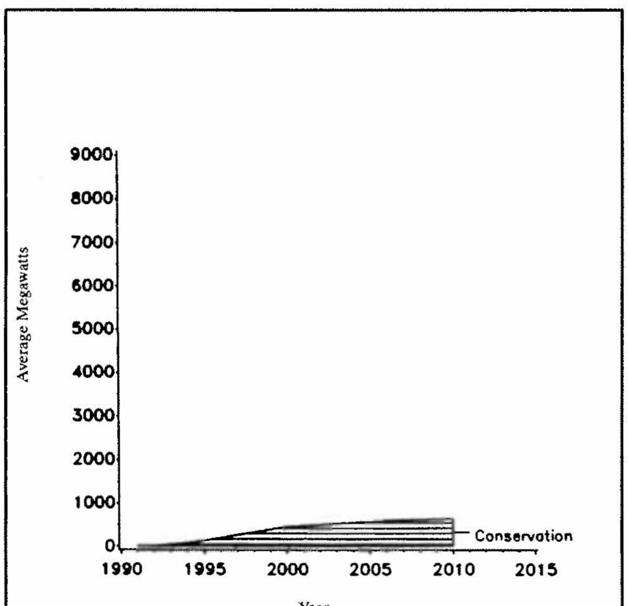
Medium-High Loads



Medium-Low Loads



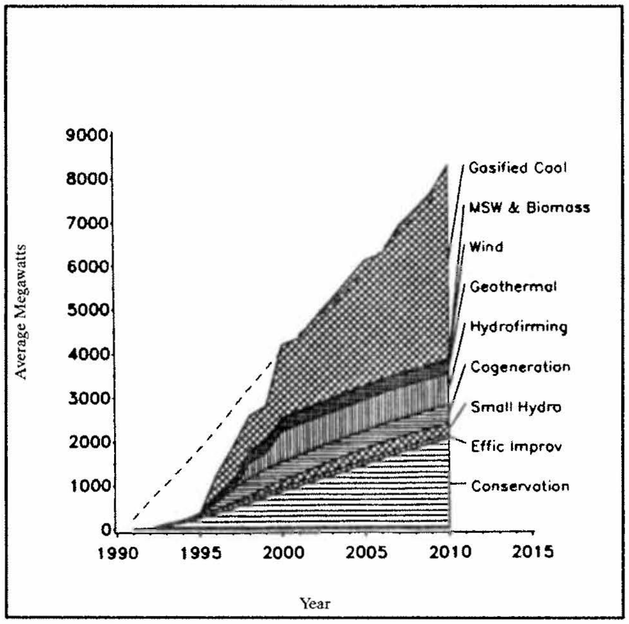
Low Loads



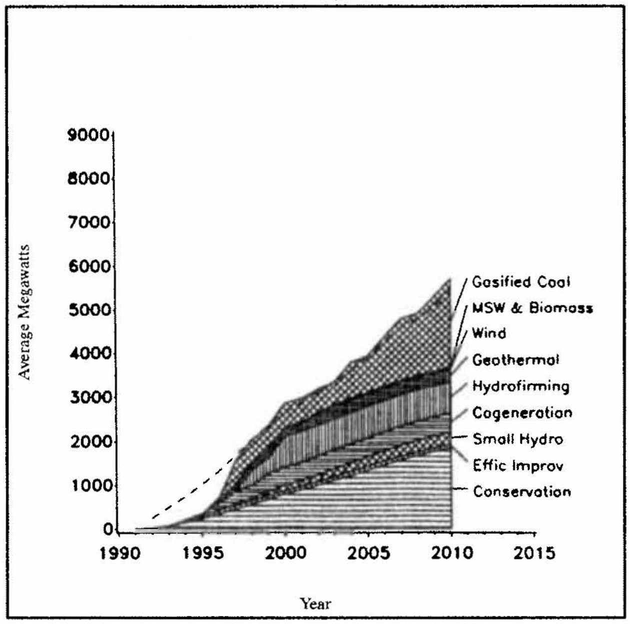
High Natural Gas Prices

Figure 10-31
Private Utility Deterministic Resource Schedules

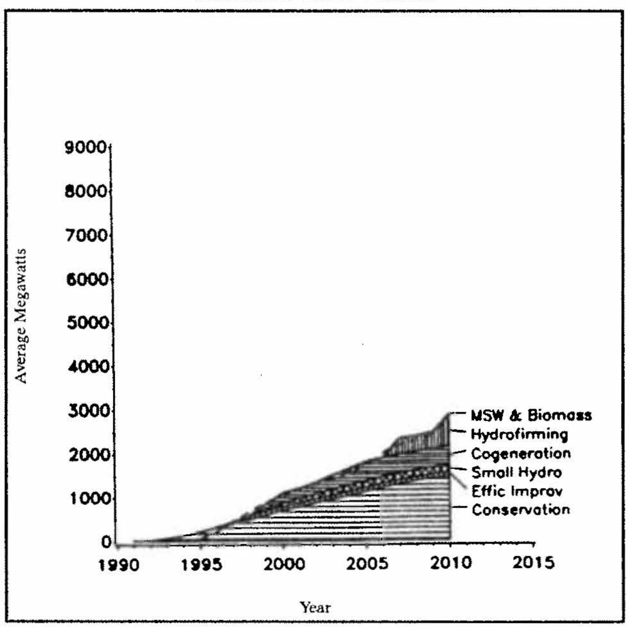
High Loads



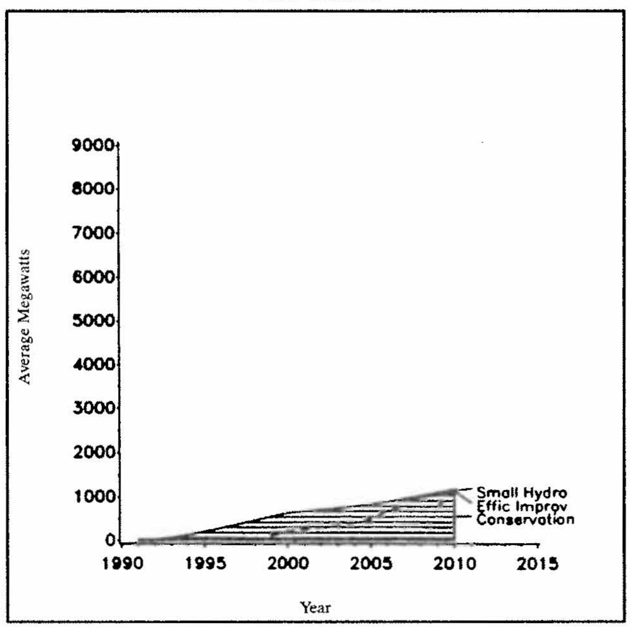
Medium-High Loads



Medium-Low Loads

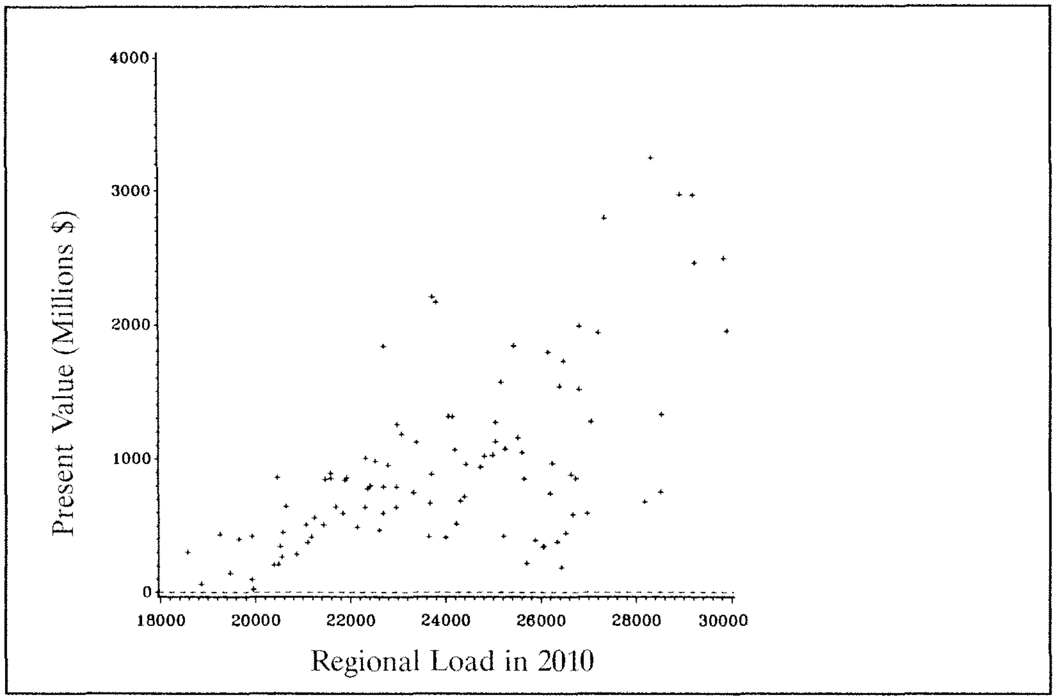


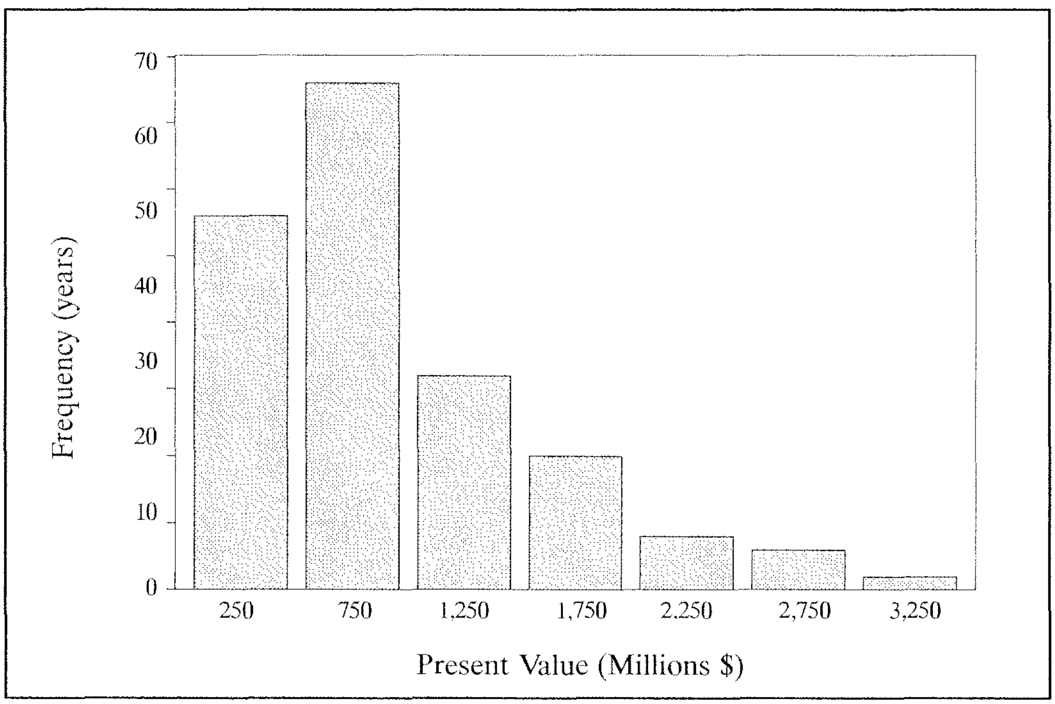
Low Loads



Cost Impacts of High Natural Gas Prices

Figure 10-32
Cost Impacts are Low in Low Load Conditions and High in High Load Conditions





Probabilistic Nature of a Portfolio

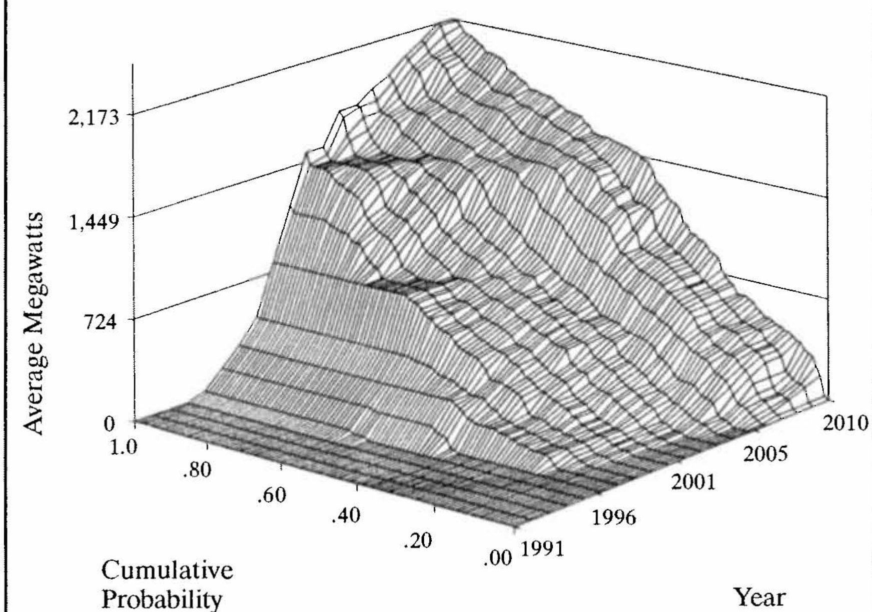
The resource strata charts from the previous section illustrate the resources needed to meet load should a particular demand and resource supply scenario occur. In fact, due to the inability to predict the future with precision, the likelihood is very small that any of these specific load paths, and the associated resource actions will materialize. The actual portfolio analysis is conducted across a large number of load paths, and the resource schedules and decision-making activity vary dynamically across the entire range of loads. Because portfolio studies are conducted across many load paths, it is possible to answer questions about the need for resource development in probabilistic terms. For example, a resource developer might be interested in the likelihood of needing significant amounts of geothermal energy by the year 1995. Results from the portfolio studies can be used to answer questions of this type.

The three-dimensional surfaces in Figures 10–33 through 10–40 illustrate the probability of need for resources in the diverse supply portfolio. The surfaces are regional composites, showing the combined resource development from the independent actions of the public and investor-owned utilities. These graphs show the probability of having a specific amount of energy online by a particular point in time. The probability axis represents cumulative probability and is interpreted as the probability that less than or equal to a specific amount of energy will be developed. For example, Figure 10–33 illustrates the range of need for energy from cogeneration. This shows a very wide range of resource need for cogeneration, with some amount of energy developed under virtually all load conditions. By the year 2000, the probability is only about 10 percent that no cogeneration energy will be needed. The probability of approximately 650 megawatts or less is about 50 percent. There is a very small chance that up to 1,500 megawatts of cogeneration may be needed by the year 2000, and almost 2,200 megawatts could be needed by 2010.

The high probability of need for significant amounts of energy from cogeneration is shared by several other of the generating resource types. Hydrofirming resources, small hydro and efficiency improvements all show energy contributions across almost the entire load range. (Note that the vertical scale for these graphs is not constant.) It is this type of robust development pattern that the Council looked for when including actions for resource development in the Action Plan. This is in contrast to resources such as nuclear, gasified coal and wind, which show a much lower probability of need. For example, in Figure 10–39, it can be seen that the probability that no energy is developed from nuclear power in the diverse supply portfolio is about 75 percent. The blocky nature of this and several of the other surfaces is due to the large unit size of the resources involved.

Resource Development Probability

Figure 10–33
Probability of Energy Online for Cogeneration



Resource Development Probability

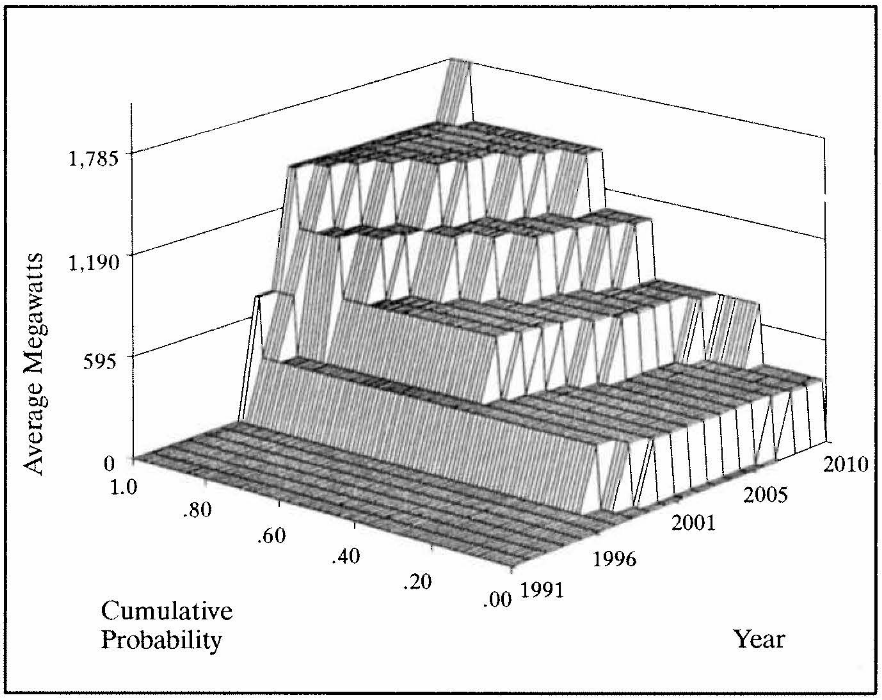


Figure 10–34
Probability of Energy Online for Hydrofirming

Resource Development Probability

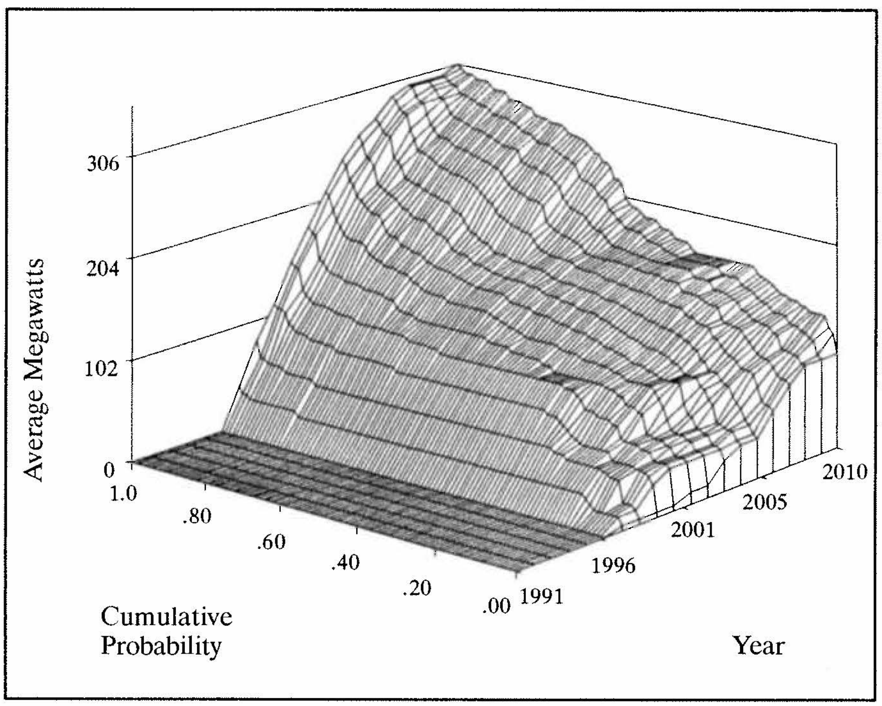


Figure 10–35
Probability of Energy Online for Small Hydropower

Resource Development Probability

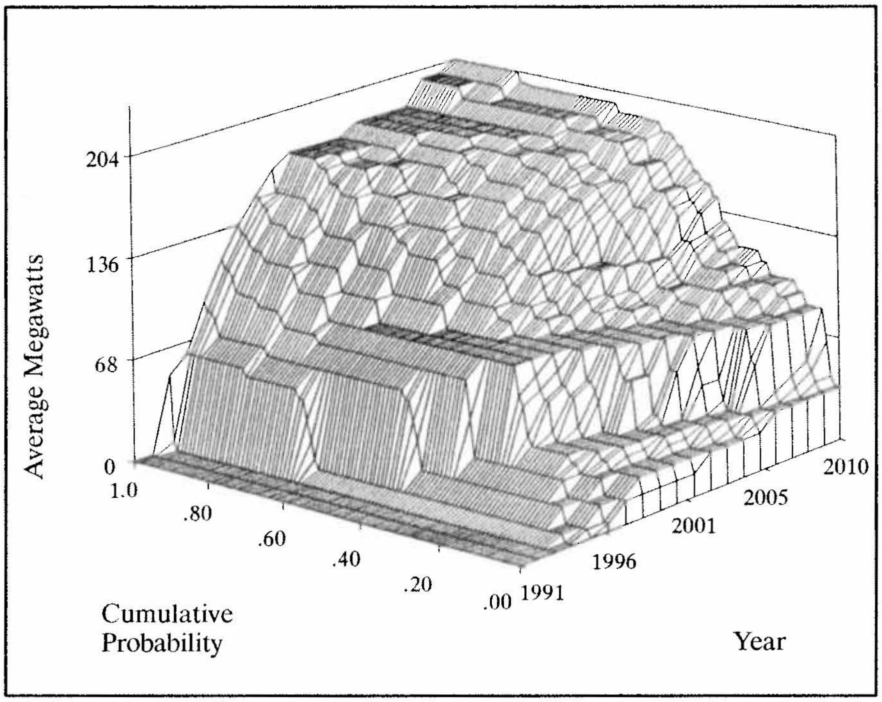


Figure 10–36
Probability of Energy Online for Hydro Efficiency Improvements, Municipal Solid Waste and Biomass

Resource Development Probability

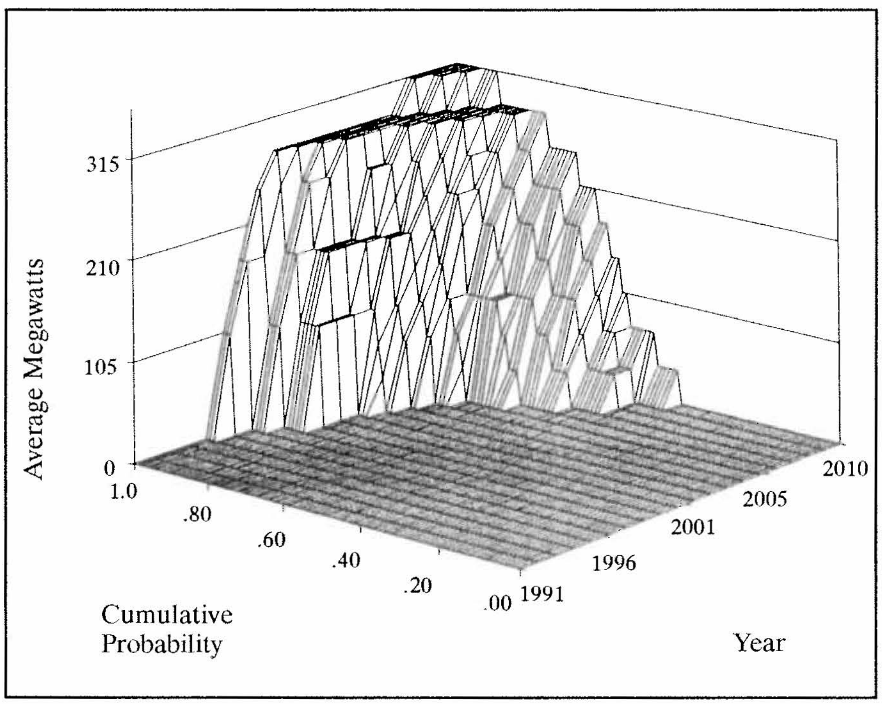


Figure 10–37
Probability of Energy Online for Geothermal

Resource Development Probability

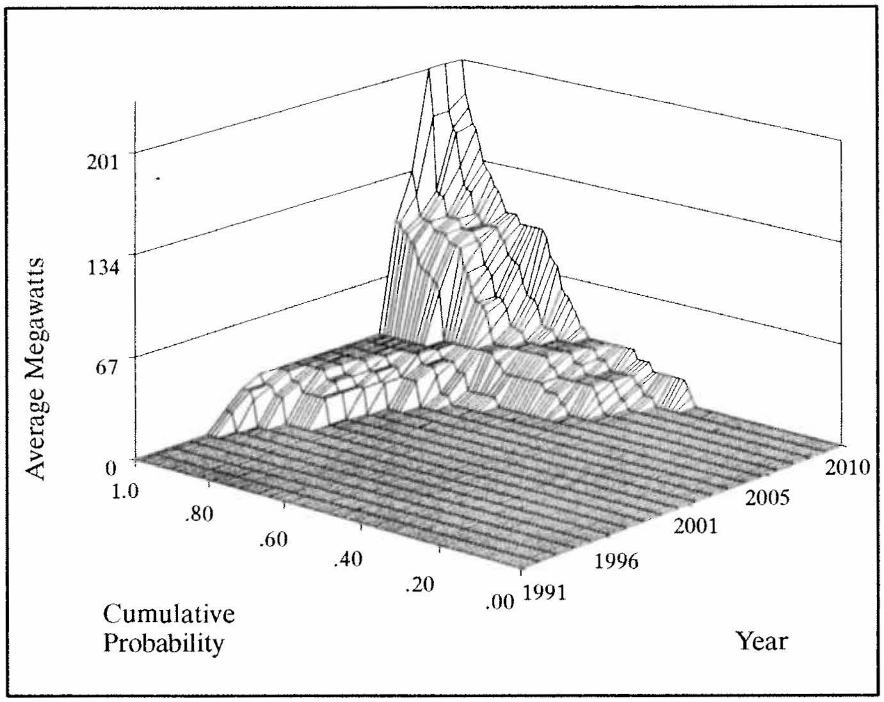


Figure 10-38
Probability of Energy Online for Wind

Resource Development Probability

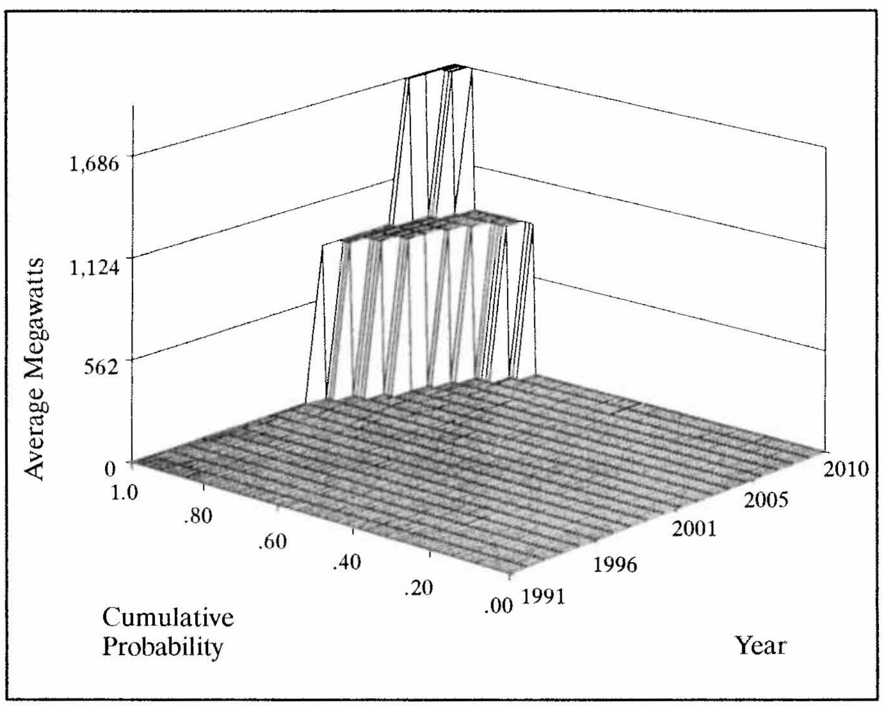
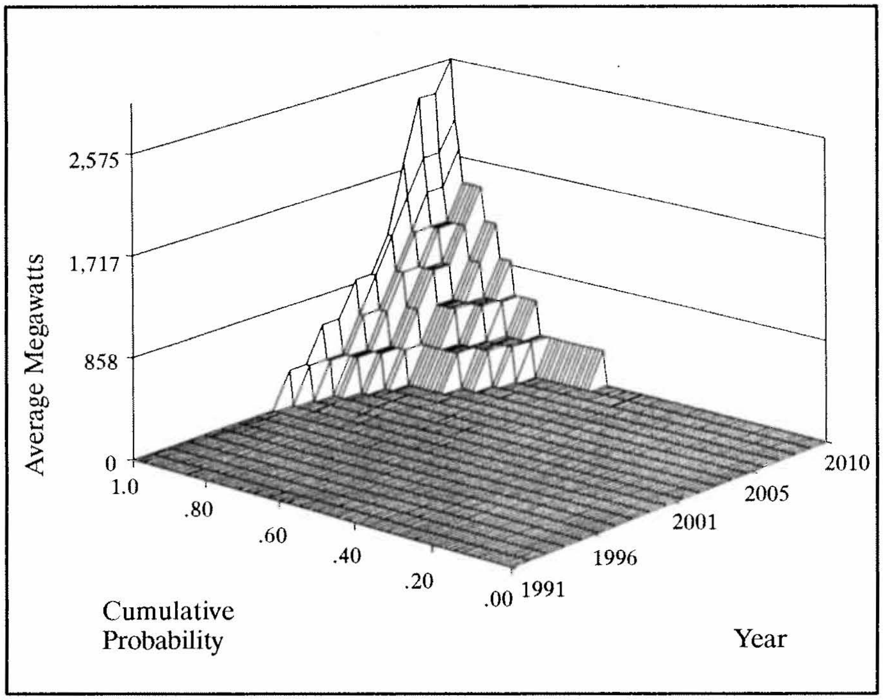


Figure 10-39
Probability of Energy Online for Nuclear

Resource Development Probability

Figure 10-40
Probability of Energy Online for Coal Gasification



Acquisition Targets

One of the exercises important for development of the Action Plan is the comparison of resource activity across the different supply and cost scenarios. Implementation of actions that are common to the alternative portfolios improves the odds the region will be prepared to deal with any of the futures represented in the alternative scenarios, and maintain the flexibility needed to alter course as events unfold.

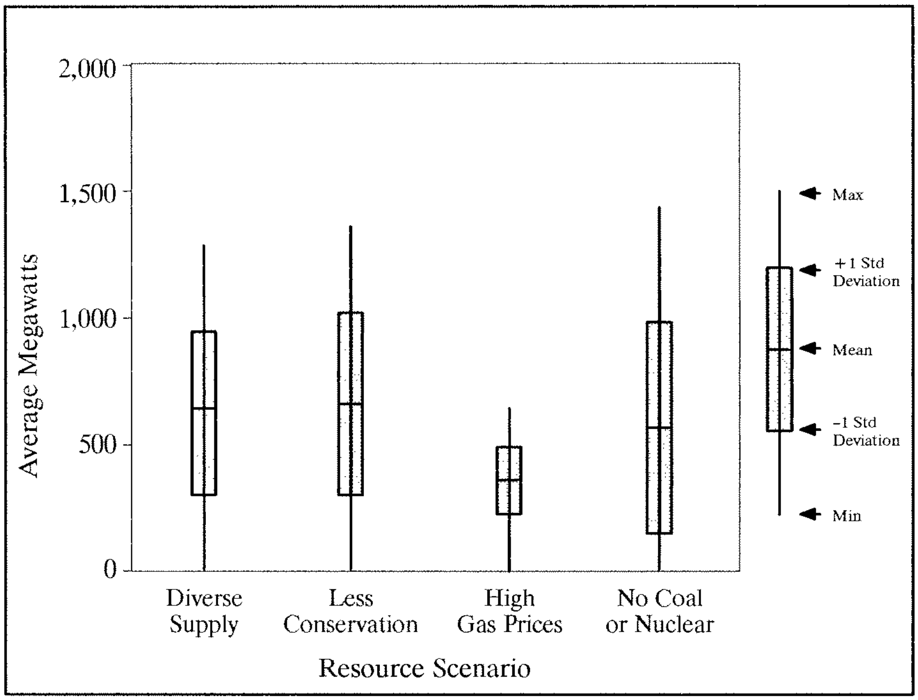
However, it can be cumbersome to make comparisons of resource activity across the different resource portfolios using these three-dimensional surfaces. Figures 10-41 through 10-48 facilitate the comparison of the resource activity embodied in the different resource portfolios. These graphs represent a snapshot of each portfolio in the year 2000 and are a summary of the information contained in the three-dimensional surfaces for that year. They show the range of resource energy online in the year 2000 for each of the alternative portfolios.

Cogeneration is represented in Figure 10-41. The bottom and top of the thin lines or needles represent the minimum and the maximum amount, or range, of cogeneration developed by the year 2000 for each of the four portfolios. The horizontal mark indicates the average for energy acquired by 2000. It ranges from a high of about 650 megawatts in the less conservation scenario down to about 350 megawatts in the high gas price scenario. The height of the vertical box on each line represents plus or minus one standard deviation for the magnitude of energy needed. It gives an indication of the amount of dispersion contained in the distribution. For the symmetrical distributions, one would generally expect about 70 percent of the observations to fall in the range defined by the vertical box. Note however, that the distributions for some of the resources are not symmetrical.

In developing the Action Plan targets for generating resource acquisitions, the Council used an array of information from across all the portfolios analyzed. The Council looked for a set of actions common to the different portfolios and then made additional modifications where it was judged appropriate. For example, small hydro shows an average development by the year 2000 ranging from 100 megawatts in the diverse supply scenario to about 120 megawatts in both the high gas price, and nuclear and coal unavailable scenarios. Additionally, the dispersion is quite small, with a standard deviation of about 30 megawatts. The Council chose 150 megawatts as the acquisition target because of small hydro's slight risk mitigation characteristics and, as these projects are assumed to be outside of protected areas, its relatively benign environmental effects.

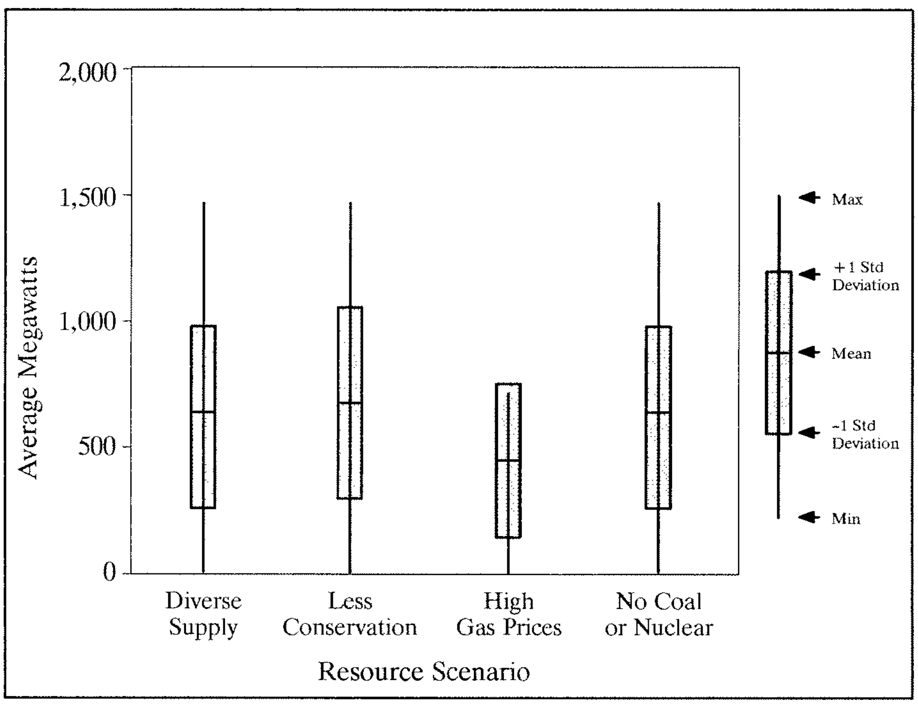
Construction Activity

Figure 10-41
Range of Cogeneration Online by 2000



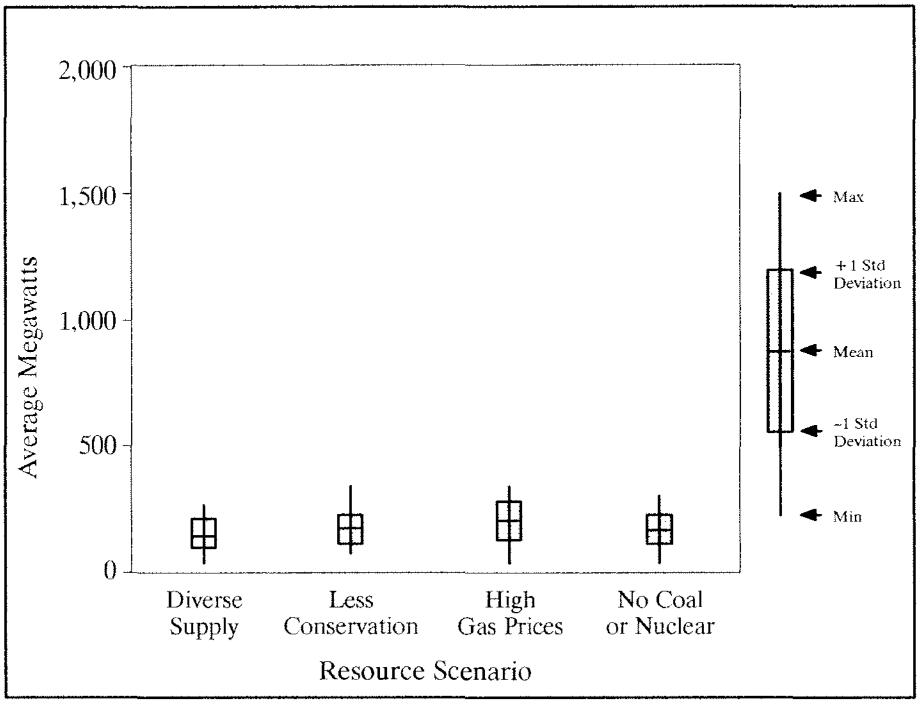
Construction Activity

Figure 10-42
Range of Hydrofirming Online by 2000



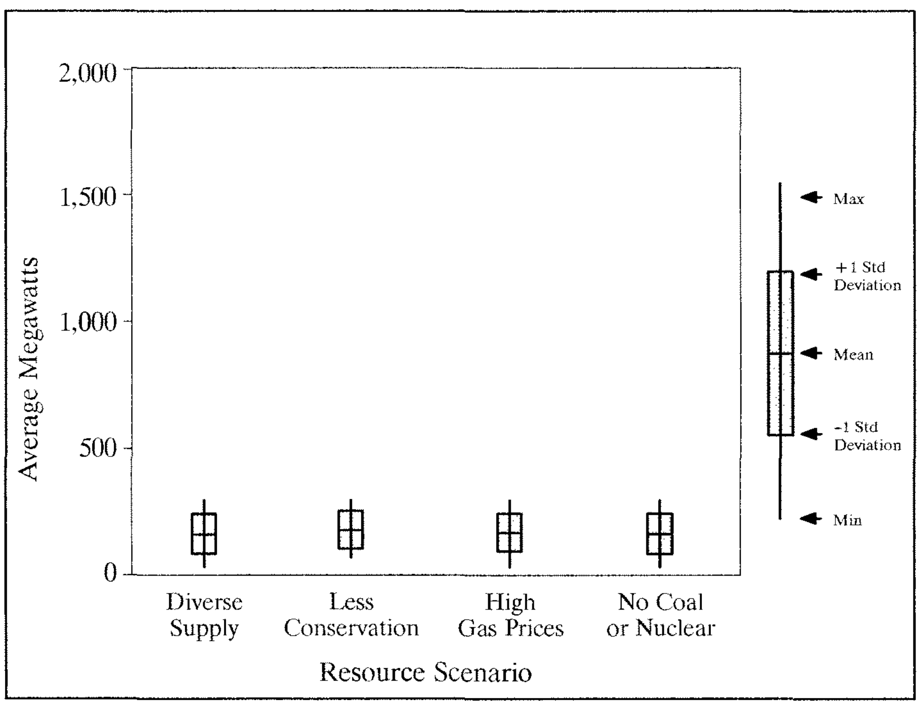
Construction Activity

Figure 10–43
Range of
Small Hydropower
Online by 2000



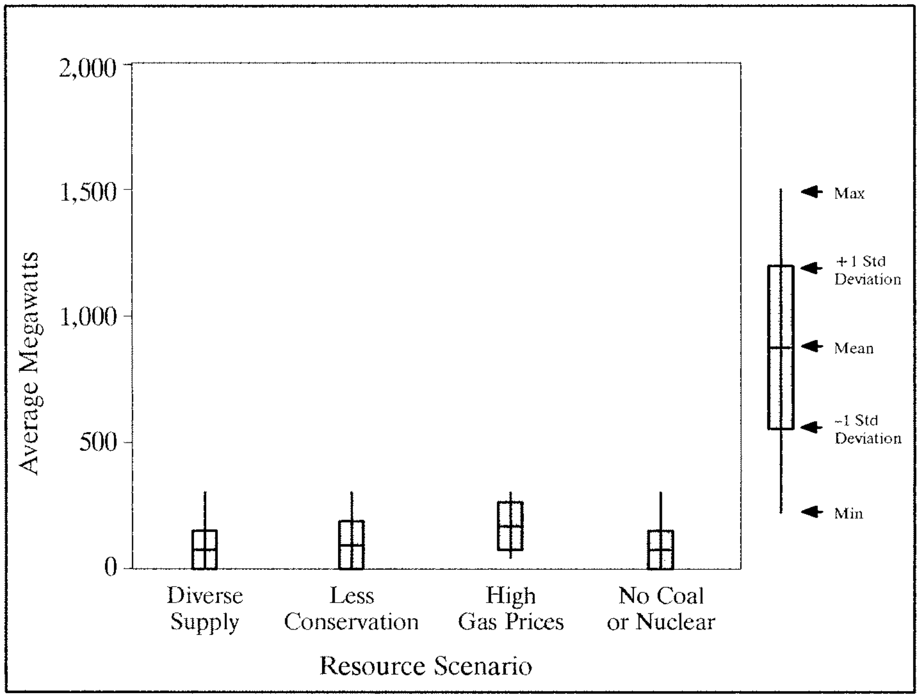
Construction Activity

Figure 10–44
Range of
Hydro Efficiency
Improvements,
Municipal Solid
Waste and Biomass
Online by 2000



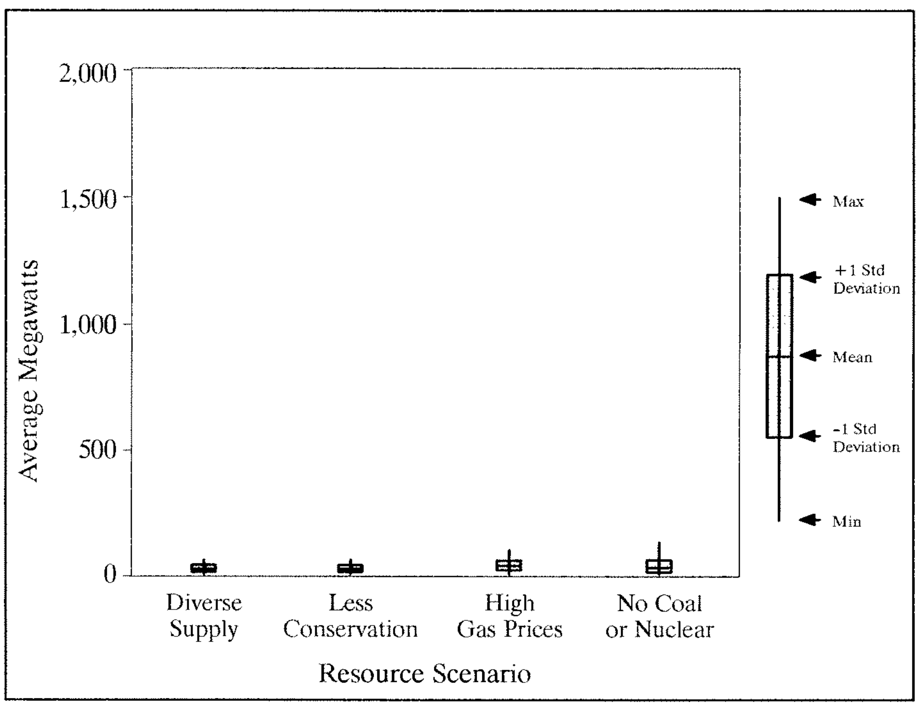
Construction Activity

Figure 10–45
Range of
Geothermal
Online by 2000



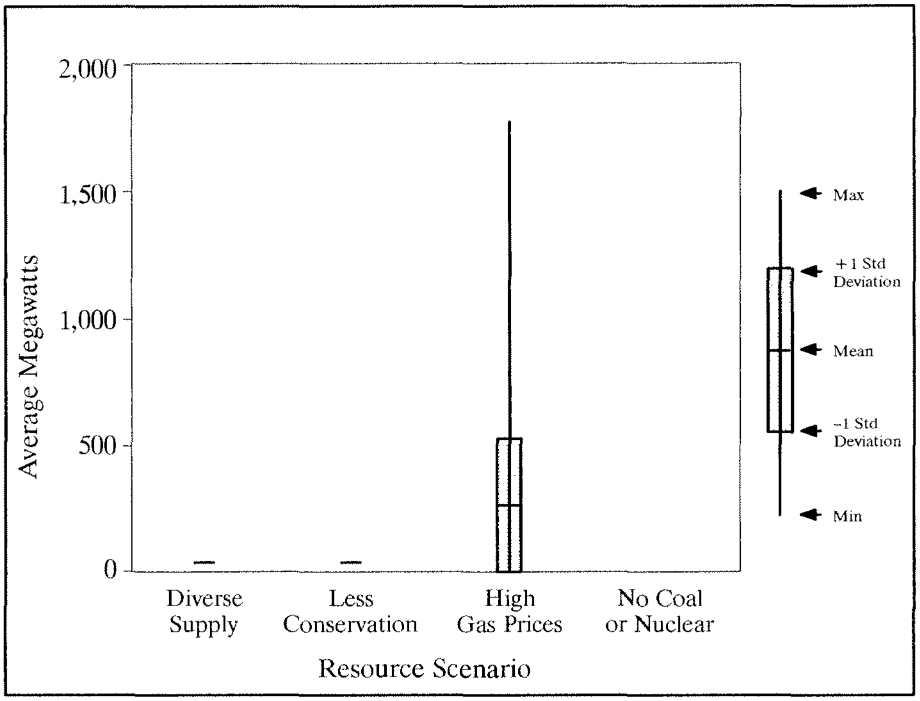
Construction Activity

Figure 10–46
Range of
Wind
Online by 2000



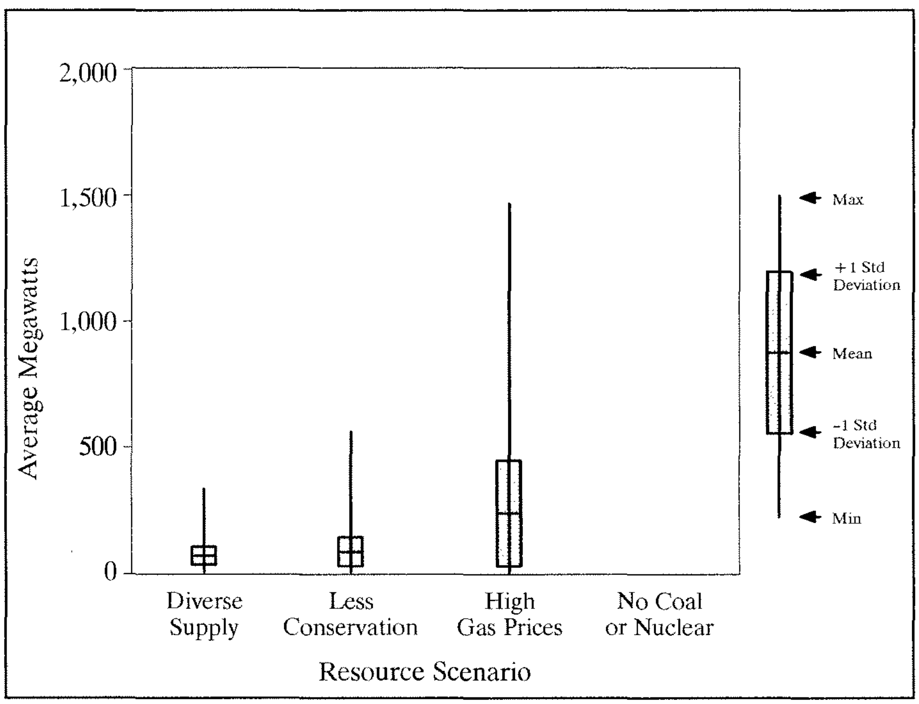
Construction Activity

Figure 10–47
Range of
Nuclear
Online by 2000



Construction Activity

Figure 10–48
Range of
Coal Gasification
Online by 2000



Option Decision Activity

In the Action Plan, the Council calls for development of an inventory of generating resource options above and beyond the energy in the resource acquisition targets. The objective of this action is to develop a diverse inventory of resource options that will reduce resource lead times and enhance planning flexibility. This can be accomplished by beginning the siting, licensing and design activities of an additional set of the most cost-effective resources over the next few years.

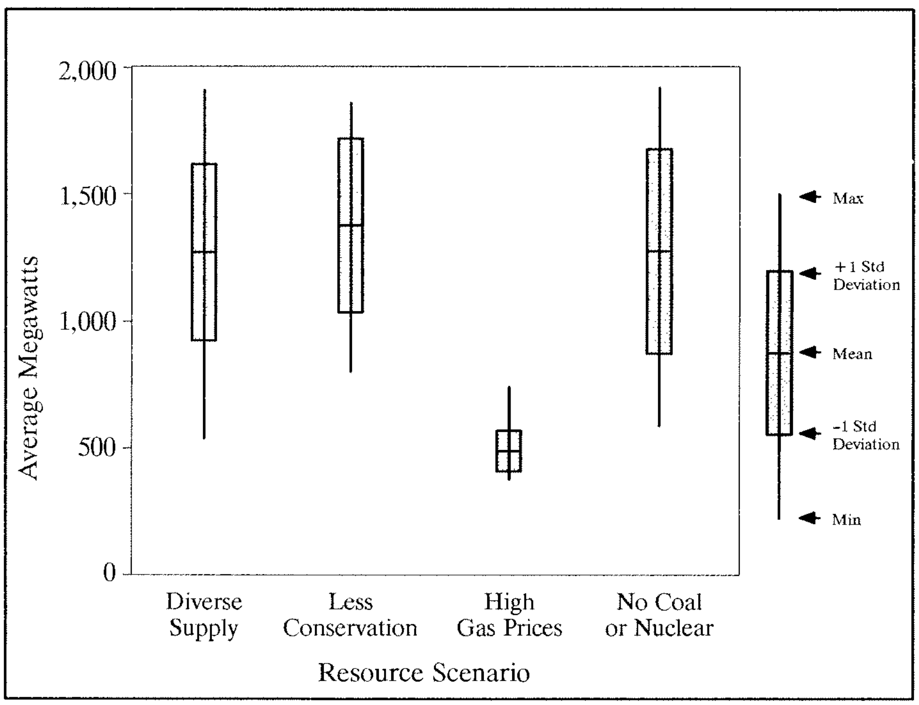
The Council used a similar approach for developing option targets in the Action Plan to that used for the acquisition targets. Comparisons were made of the option decision activity across the alternative portfolios and modified with judgment where appropriate.

Figures 10-49 through 10-56 illustrate the range of option decisions made in the four alternative portfolios. These graphs can be interpreted in the same way as the previous set, except that the variable represented here is the cumulative energy on which decisions to initiate options have been made by the year 2000. The horizontal mark is the average across 100 load paths; the box represents plus or minus one standard deviation, and the top and bottom of the vertical lines are the maximum and minimum. These graphs again represent regional aggregates. A wide range of decision activity is seen for almost all the resources across the four resource cost and supply scenarios investigated here.

To develop the Action Plan targets for options, the Council typically used the average level of option decisions made by 2000, minus the action plan acquisition target. Because all generating resources are optioned in the portfolio analysis before they can be acquired, the cumulative option decisions by 2000 includes all generating resources acquired by that year. Option energy above and beyond the acquisition level becomes the option targets. For example, the Action Plan target of 750 megawatts of cogeneration options is based on the approximately 1,400 megawatts of options in the reduced conservation scenario, less the cogeneration acquisition target of 650 megawatts.

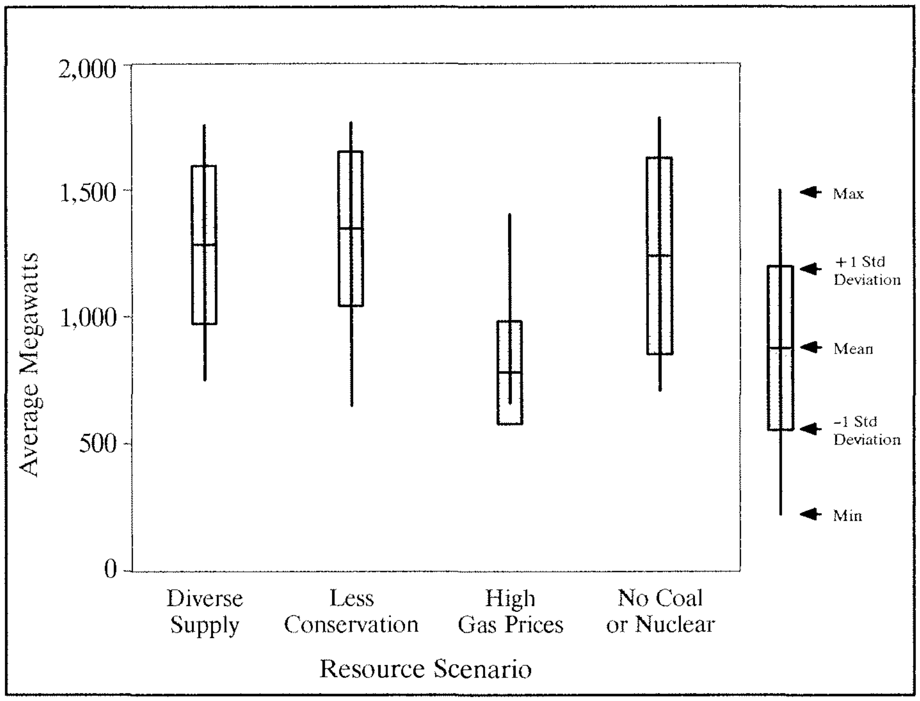
Option Activity

Figure 10-49
Range of Option Decisions for Cogeneration Made by 2000



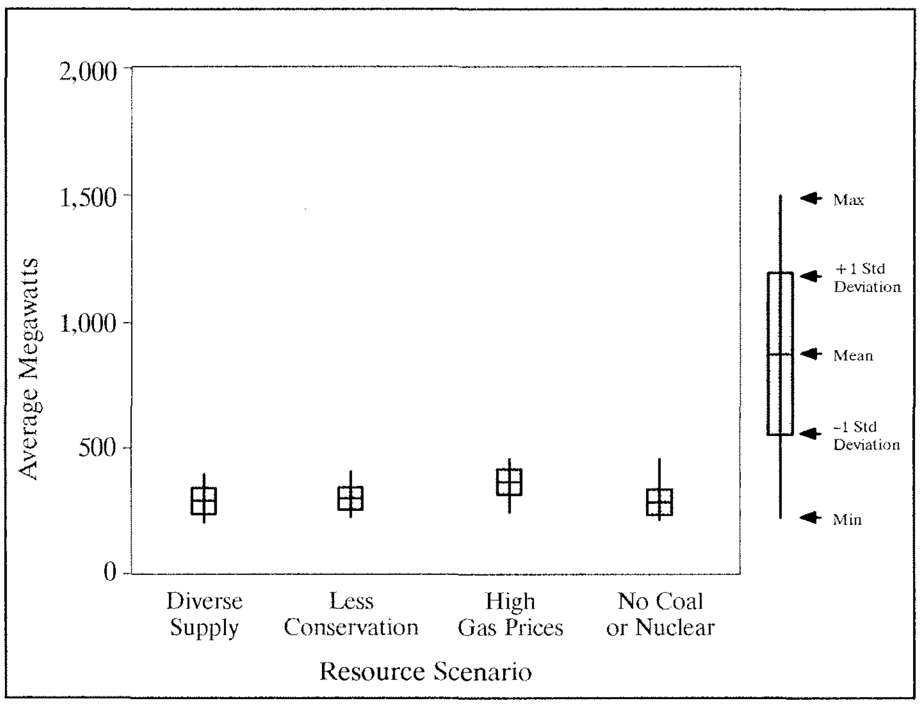
Option Activity

Figure 10-50
Range of Option Decisions for Hydrofirming Made by 2000



Option Activity

Figure 10-51
Range of Option Decisions for Small Hydropower Made by 2000



Option Activity

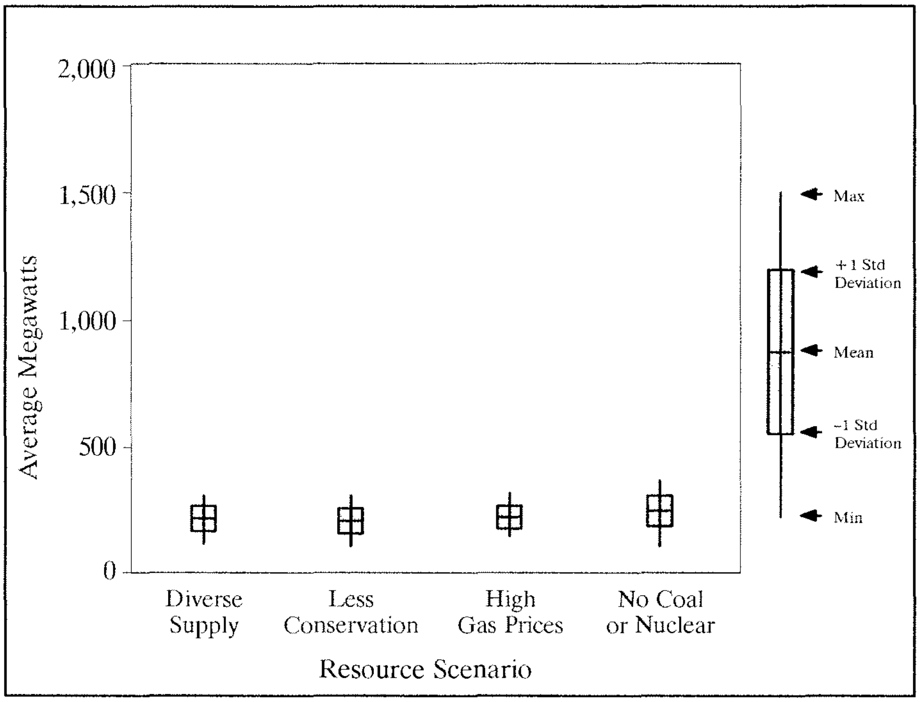


Figure 10-52
Range of Option Decisions for Hydro Efficiency Improvements, Municipal Solid Waste and Biomass Made by 2000

Option Activity

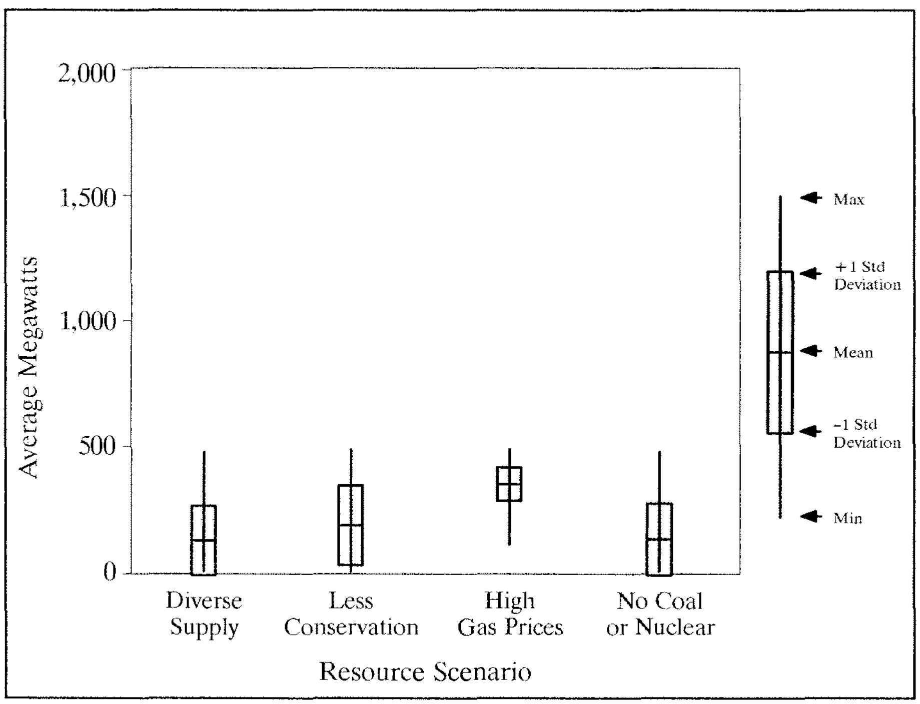
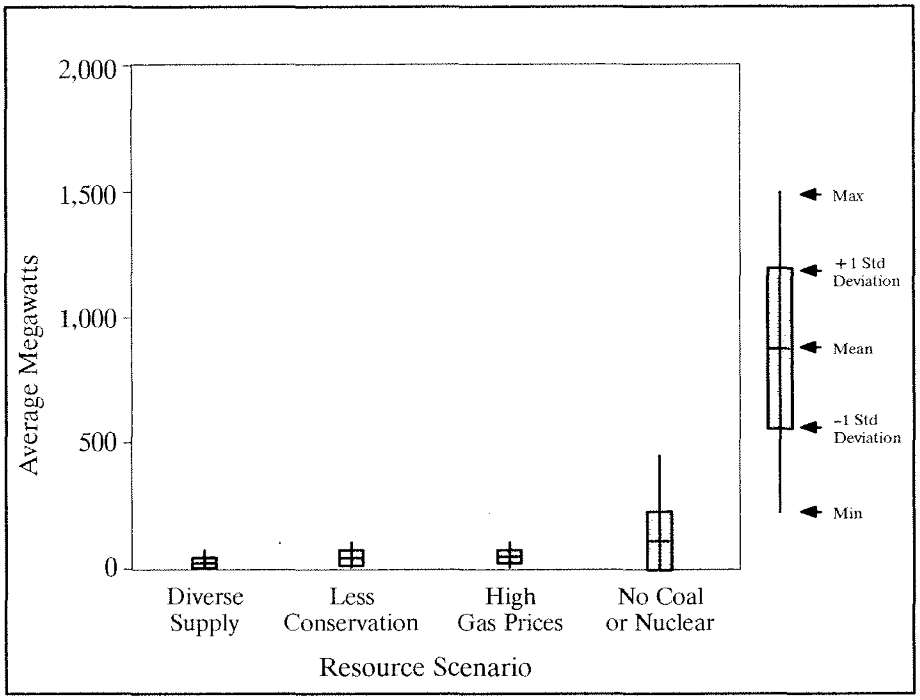


Figure 10-53
Range of Option Decisions for Geothermal Made by 2000

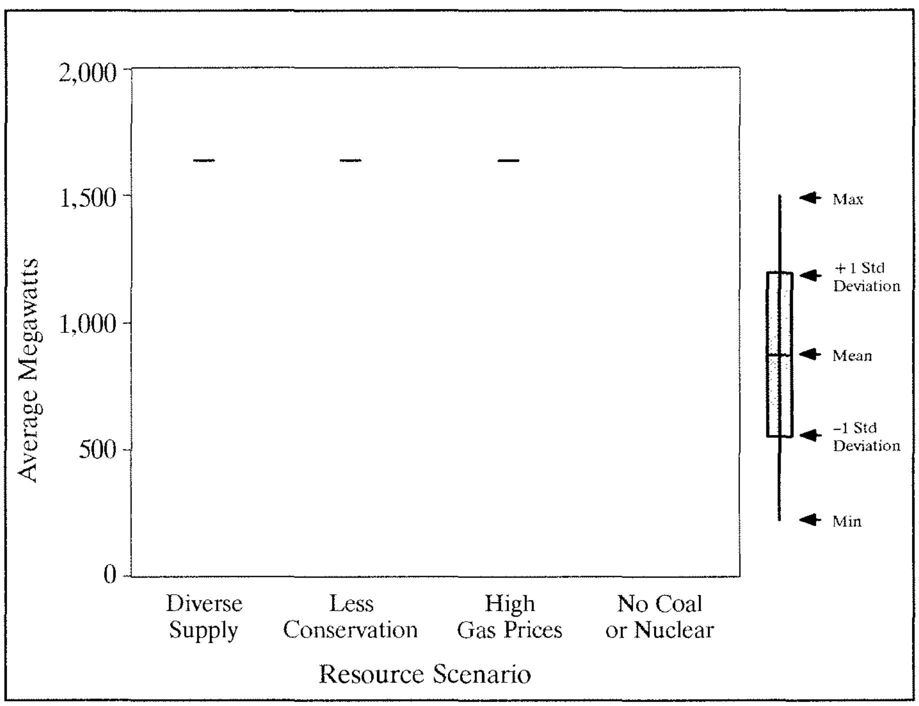
Option Activity

Figure 10–54
Range of Option Decisions for Wind Made by 2000



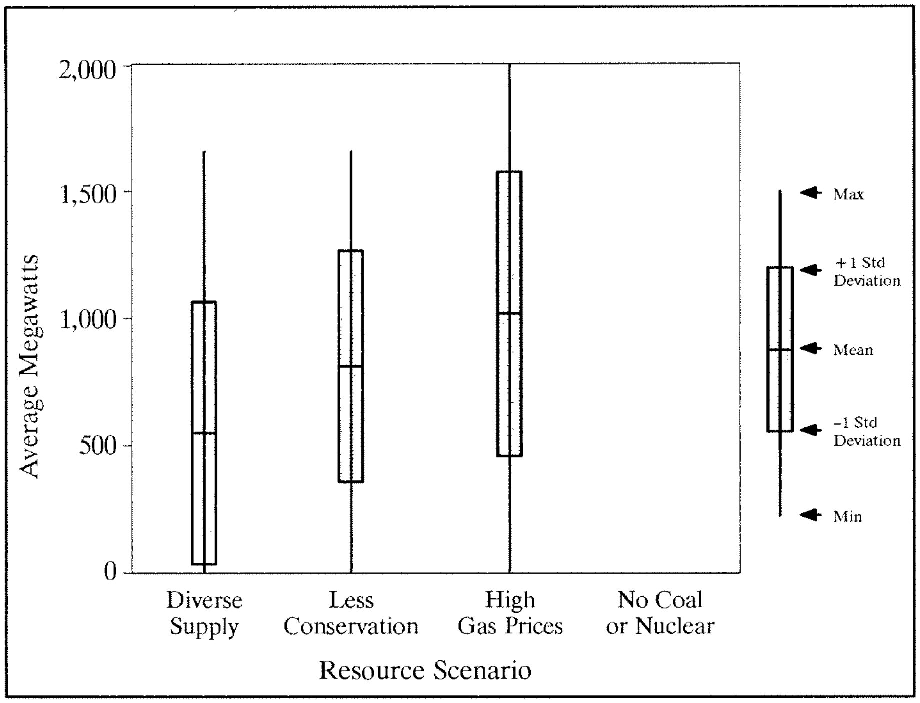
Option Activity

Figure 10–55
Range of Option Decisions for Nuclear Made by 2000



Option Activity

Figure 10-56
Range of Option Decisions for Coal Gasification Made by 2000



Conclusions from Resource Portfolios

These planning exercises all reinforced the same themes. First, in almost all scenarios, the resource that helps buy the region time to adapt to uncertainties is conservation.

For this reason, conservation plays a central role in the Council's Action Plan. Conservation programs need to be implemented quickly and brought up to a stable level of activity, so that the region can develop an infrastructure for delivering energy savings. Labor, technology, materials and expertise must be acquired to secure the region's conservation resources. A major conservation acquisition program will require a steady, long-term commitment of both staff and budgets.

Many of the resource portfolios illustrated the need for an inventory of resources that can be brought into operation without long delays. Among the best resources for responding to quick economic or other turnarounds are gas-fired technologies.

Obviously, the acquisition of significant amounts of gas-fired technologies poses an increasing risk, due to future uncertainty surrounding gas availability and prices. Nevertheless, the Council recommends that the region acquire the lowest cost cogeneration and begin the process of identifying sites and obtaining the necessary licenses and approvals for higher cost gas-fired resources. These could either operate in a cogeneration mode or as stand-alone plants to back up the region's existing hydropower system.

In a number of the portfolios, significant amounts of new or existing resources may become unavailable. In these events, the primary resources that the Council and the region can turn to are newer, emerging technologies with which we have less experience. For this reason, the Council has selected resource confirmation activities to improve our understanding of and our ability to predict the cost and availability of geothermal, wind, solar and other resources.

Also, new conservation technologies are being introduced each year. It is important to promote this development, so the region can rapidly assimilate new conservation measures as they become commercially available and cost-effective.

The Council's findings in this planning process led directly to the actions described in the Action Plan. These actions are designed to secure the resources that are needed by the region at the lowest possible cost. Additional actions are identified to help shorten lead times and better manage the risks and uncertainties that the region faces.

The Value of Regional Cooperation

The four preceding portfolios were developed assuming that Bonneville and the investor-owned utilities purchase new resources independently. Each undertakes only those actions that meet the needs of its own customers. The Council has used this assumption throughout the plan because the investor-owned utilities have shown little interest in using the requirement contract provisions of the Act for coordination of future resource development. It is the responsibility of the Council to produce a plan that is realistic and useful and to prepare for a future actions based on realistic assumptions about utility actions.

However, there are in fact very large benefits to be gained through regional cooperation. Because of the disproportionate energy needs of the public and investor-owned utilities, the "split region" assumption frequently results in the investor-owned utilities developing more expensive resources than Bonneville and the public utilities would have to develop to meet load growth. Regional cooperation would allow the region to purchase all of the lowest cost resources first, regardless of ownership.

The Council performed a study to investigate the value of regional cooperation. This study assumes that all resource development can be coordinated through Bonneville and that public utility conservation potential and Bonneville's hydrofirming potential could be developed earlier than would be justified by public utility load growth. The results are shown in Figure 10-57. The mean value of this benefits distribution is $3.6 billion. Benefits are seen across the entire spectrum of load conditions and range from $1.6 billion to $7.2 billion. The maximum values occur in the higher probability medium-low to medium-high load conditions. It is in this portion of the load range that public utilities could accelerate the development of lower cost resources to defer the higher cost thermal resources otherwise developed by the investor-owned utilities.

About $2.5 billion of the $3.6 billion expected benefit is due to the improved coordination of resource development. It's derived largely through accelerated development of conservation, hydrofirming, and nuclear resources, and the deferral of higher cost resources like coal gasification. The remainder of the benefits, about $1.1 billion, comes from increased revenue to the region for sale of nonfirm hydro to out-of-region markets. This portion of the benefit is an artifact of the current Bonneville rate structure. Under current rate policy, the price Bonneville can charge for much of its nonfirm sales is limited to Bonneville's average system cost. In the coordinated region studies, the investor-owned utilities place much of their load growth on Bonneville through requirements contracts. This leads to higher average system costs for Bonneville and in turn to higher secondary revenues. This benefit is essentially a transfer payment between the Northwest and the Pacific Southwest. The degree to which it would actually occur depends heavily on future rate policy.

Because the benefits of regional cooperation are so large, the Council recommends that, wherever possible, utilities design ways to share resources and resource development. For example, slow-growing utilities and those with surplus power would be able to cost-effectively operate conservation programs if they could sell their energy savings to a utility that needs resources. Other low-cost resources also might be developed if there were access to transmission lines so the power could be moved to utilities that need it.

Resources Outside the Portfolio

The purpose of this section is to describe what it means for a resource to be included in the resource portfolio of the Council's 20-year power plan and, also, what it means for resources that are not in the portfolio. Since the Council's first power plan in 1983, there has been confusion about what the 20-year resource portfolio represents. The resource portfolio gets a lot of attention in the Council's planning, because it is the product of months of issue papers and public comments on the building blocks of the plan. The issue papers lay out economic and demographic assumptions, financial assumptions for prospective resource developers, costs, availability and environmental values for all *identified* new resources, assumptions regarding existing resources, and so forth.

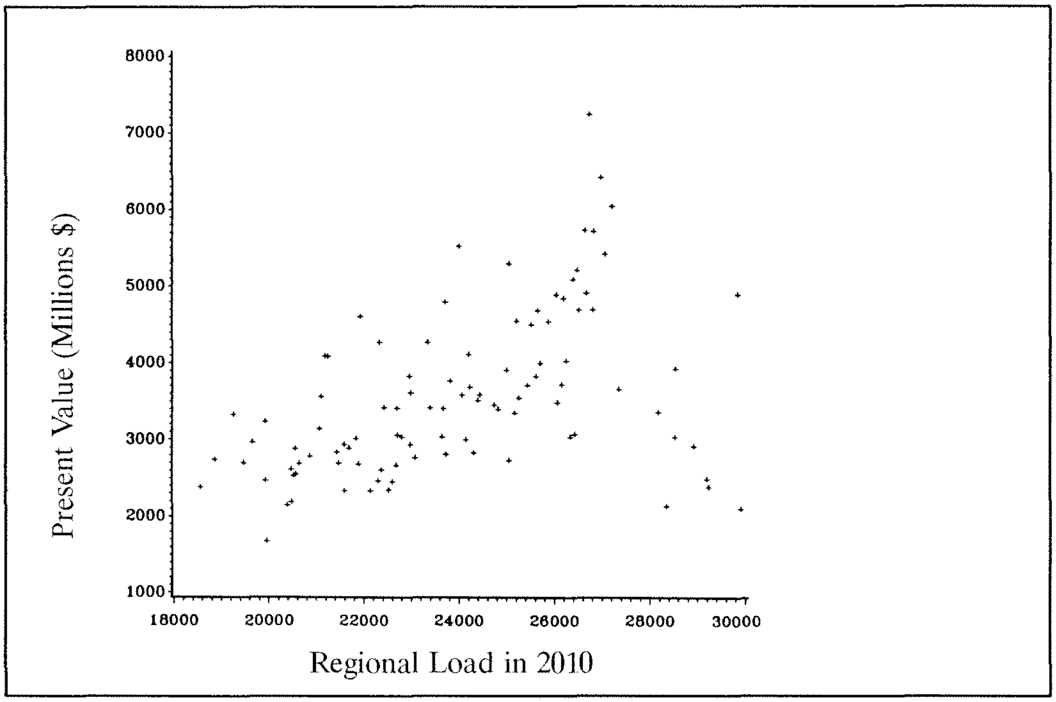
Because the resource portfolio is an important step in the Council's work and evolves over the entire planning process, it is natural to focus on the results. Resource developers look to the portfolio to find out what the plan recommends for their particular resource. However, as important as the resource portfolio is to the Council's plan, it is impossible for the plan to identify and anticipate all future resource alternatives. The resource portfolio in this light is a benchmark set of resources against which the Council can evaluate all future resources. No irreversible commitments are implied by the selection of a given resource portfolio. The Action Plan is the only place where the Council documents its preferred activities, many of which may involve irreversible commitments.

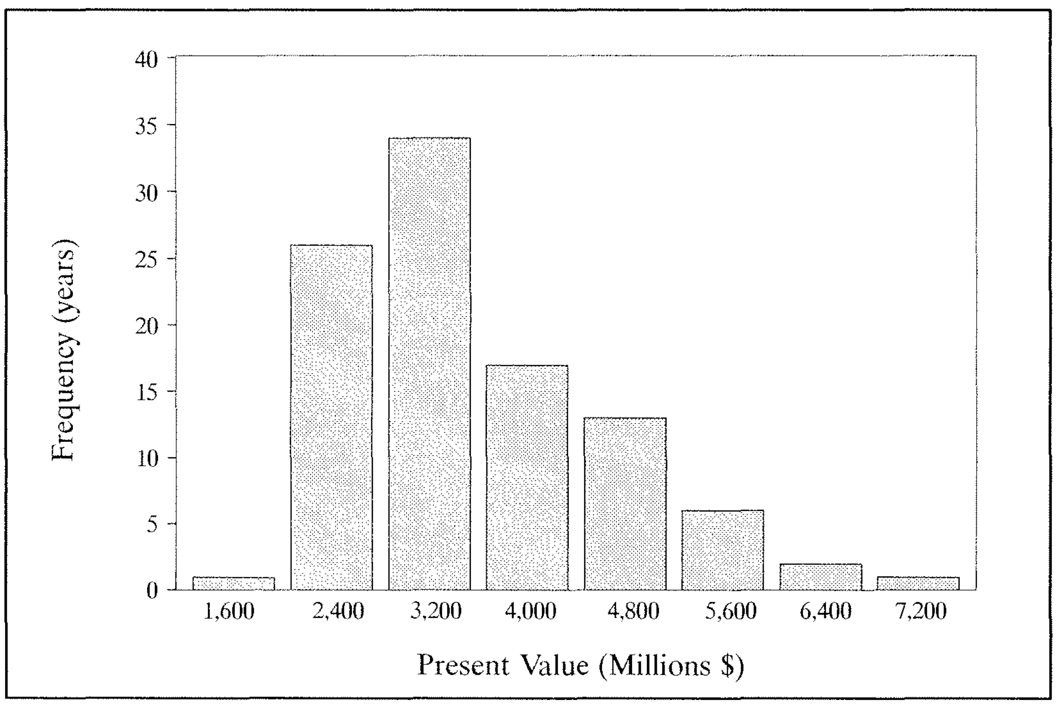
What Does the Resource Portfolio Represent?

The previous section discussed the information and models that go into the development of the 20-year resource portfolio. Resources with relatively well known characteristics are selected in the best chronological order to deliver power at the lowest cost over a range of future loads. The Council understands that resources in the portfolio may be different from those actually acquired over the next 20 years. The resources in the portfolio are those that are considered to be available and reliable today, and if a decision had to be made today for the next 20-years of resource acquisition, this portfolio probably would be the lowest cost and least risky.

Regional Cooperation Benefits

Figure 10-57
Benefits of Regional Cooperation are High





However, the only decisions that have to be made in the power plan are those near-term decisions necessary to acquire resources or decisions to build the capability to acquire a resource in the future.[5] Capability can be developed through pilot programs, research and development, and options. The Council fully expects that other resources, through technological breakthroughs or better financing terms, for example, ultimately could be more desirable and, to the extent they are consistent with the plan, should be acquired in the future.

Resources that are first in the portfolio clearly have a higher probability of being acquired than resources that are not needed until after the turn of the century, but even those first resources are not guaranteed to be acquired. What is true is that resources with the same or similar characteristics and with the same or lower costs should be acquired, assuming that need arises. The Council's resource portfolio is composed of *known* resources. For example, combustion turbines, either single-cycle or combined-cycle, are a well known source of power that fits well within the region's power system. If a different resource with similar characteristics and lower costs were offered in response to a bid to supply power, that resource would be selected, as it should be. Such a resource cannot be identified at the present time; however, in the future there may be resources developed that may have all of the characteristics of combustion turbines at lower or similar costs.

Categories of Resources Not in the Resource Portfolio

Any resource not in the portfolio can compete with any resource in the portfolio on the grounds of cost, power characteristics and environmental suitability. There are a number of reasons why resources are not included in the portfolio:

1. First and foremost are resources that are not cost-effective. The definition of cost-effective includes a finding that the resources are, or will be, reliable and available when they are needed.
2. Specific resources that cannot be identified at this time.
3. Out-of-region resources beyond what is currently under contract. This category is a special subset of category two.

Each of these categories of resources is discussed in more detail below.

Resources that are Not Cost-Effective

To be included in the resource portfolio, resources must be more effective at reducing the present-value cost of serving regional loads than competing resources. In addition, there are some resources deemed by the Council to be too risky or environmentally sensitive. An example of the latter case is hydropower development on the many miles of streams the Council has included in protected areas.

However, in its analysis, the Council uses financial assumptions typical of public utilities, investor-owned utilities and independent power producers. Clearly, not all developers within each category have access to capital at the same costs. To the extent that individual developers have access to low-cost capital, they may be better equipped to respond to a request for proposal.[6] Given that the resource being proposed satisfies all parts of the definition of cost-effectiveness, and is compatible with the goals and objectives of the plan, that resource should be acquired, again regardless of whether it is contained in the resource portfolio.

Specific Resources that Cannot Currently be Identified

Some resources, such as cogeneration and small hydropower, are included in the plan based on rough estimates of how much is available and how much will be developed within certain estimated costs. There may be more, or less, than is assumed. If initial estimates were too low and there are more cost-effective resources in these categories, they should be acquired as needed.

This category might also include some renewable resources. Because all renewables are site specific and many await better characterization of the resource (wind, solar insolation, geothermal heat, etc.) that will drive electric generators, it is virtually impossible at this time to determine all of the possible renewable resources that can and will be developed.

Resources from Out-of-Region Suppliers

Out-of-region resources play two roles in the Council's plan. First, they provide alternatives to the regional resources identified in the plan's supply curves and resource portfolio analysis. Second, they provide a source of emergency purchases in the case of firm deficits in the Council's portfolio analysis. These two roles are quite different and have different implications for the analysis underlying the plan. Each will be described in turn.

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5. Resources appear in the portfolio because they are cost-effective, which includes an assessment of their reliability, availability and compatibility with the region's power system. If other resources, not identified in the portfolio, but with similar characteristics, are brought forth, the Council will be prepared to determine their consistency with the plan.

6. Developers typically can finance plants with a high percentage of debt capital. This can result in a private developer being able to build a resource at lower costs than, for example, an investor-owned utility, which is constrained to use no more than a certain fraction of debt capital.

The role of regional resource alternatives has been discussed in general terms above. New resources acquired over the next 20 years could include exchanges with and resource purchases from British Columbia, Alberta, California, the desert Southwest, Utah and any other interconnected systems. Out-of-region resources, beyond those currently under contract, have not been specifically included in the resource portfolio. Out-of-region resources have not been included because 1) they cannot be identified at this time, and 2) if they could, there would be no good way of estimating the acquisition price and other terms and conditions of the agreements. However, based on past experience, there will be ample opportunity to negotiate cost-effective exchanges with connected systems. The Council is aware of the many opportunities that exist for utilities. Out-of-region resources should be secured if they cost less than those in the resource portfolio and are operationally and environmentally compatible.

Finally, there are about 15,000 megawatts of gas-fired generation in California, much of which is slated for retirement. The Council is including in its plan actions to begin the development of hydrofirming resources. California's gas-fired generation might be an alternative to construction of new plants in the Northwest. Negotiating with California to keep those resources in a ready state could result in lower costs than building new resources in the Northwest. Environmental considerations in southern California might interfere, however with the Northwest using California's gas-fired generation.

The second role, that of a source of emergency purchases, is more complex to describe. In the computer modeling for the Council's portfolio analysis, there are occasions in which lead-time constraints do not allow sufficient resources to be acquired to meet firm loads. In those cases, either or both of a supply of emergency purchases and an estimated cost of load curtailment are necessary in order to calculate a cost to that event. The cost is necessary because a resource strategy that consistently undershoots load because of, for example, long lead times should be penalized in terms comparable to the other costs that it incurs, such as capital and fuel costs.

The magnitude of these costs, emergency supplies and the cost of failure to meet load, affect the option and build levels that are appropriate for the Northwest power system. (The role of option and build levels is described further in the discussion about the Council's decision model.) High costs imply that higher option inventories and building ahead of perceived need are best; low costs imply that it is economic to take chances with underbuilding because the consequences are slight.

The Council conducted a preliminary investigation of sources of emergency purchases and concluded that approximately 1,500 megawatts, broken up into three 500 megawatt blocks (at 3.0, 3.5 and 4.0 cents per kilowatt-hour in real terms) was reasonable for the limited purpose of modeling the resource portfolio. If further investigation indicates that a reliable emergency supply exists, the Council may wish to include short-term purchases in future resource portfolios as substitutes for firm resources.

Summary

This section is intended to clarify some of the misunderstanding about the role of the resource portfolio in the Council's plan. Readers should not go away with the idea that the resource portfolio is unimportant. The process of developing the resource portfolio forms the basis for the Council's Action Plan and for the Council's future determinations of whether alternative resources are consistent with its plan. Resources in the portfolio and those categories of resources not included are all addressed in the Action Plan. For example, the Action Plan includes actions to ensure that promising resources ultimately can be competitive with resources in the portfolio. These actions are influenced by what is learned about resource compatibility and costs in the system analyses.

All planning proceeds from what we currently know. The goal of good planning is to be able to react to unforeseen events, both good and bad. Reliable, compatible, environmentally sound and low-cost resources always should be chosen, wherever they are found.

APPENDIX 10-A

DRAFT PLAN PORTFOLIO STUDIES

Draft Plan Portfolios

During development of the draft plan, the Council conducted a number of sensitivity studies as part of the resource portfolio analysis. There was insufficient time between the close of public comment on the draft plan and adoption of the final plan to rerun all of these studies with the final data assumptions. In the final plan, the Council selected four representative resource portfolios, rather than a single, base-case portfolio, to illustrate how the power plan addresses various uncertainties facing the region. No single resource portfolio, nor any single list of resources, should be perceived as a list of resources to acquire. Resource acquisitions should be guided by the Action Plan. The studies that formed the basis for many of the recommendations in the draft plan are included here as reference material. Note that the present value cost results for these studies is expressed in 1988 dollars.

The Council realized that many of the assumptions in the draft plan will turn out to be different than forecast today. Some of these uncertainties, such as load growth and hydro conditions, are treated explicitly in the portfolio modeling. Other uncertainties, such as future fuel prices, environmental effects and resource supply, are not incorporated directly into the analysis, but can still have a large impact on resource decisions. While the Council believes that the data development process has produced reasonable and balanced estimates for input into the modeling process, there is little question that significant uncertainty remains regarding many of the important parameters in power planning.

To gain insight into the effect of some of these uncertainties, the Council examined the consequences of a variety of alternative future resource portfolios and their potential impact on the Ation Plan. The ramifications of each alternative portfolio were analyzed, discussed and debated. The purpose of the exercise was to explore the various energy futures possible for the region. These exploratory studies can help identify the more significant risks the region faces and identify actions that help manage this risk. Some actions are robust. That is, they can work over a wide range of uncertainty to mitigate risk. It's important to identify these actions and incorporate them into the Action Plan.

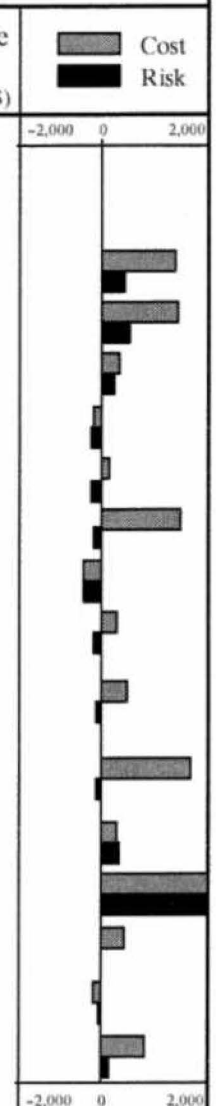
Alternative Draft Plan Portfolios

In developing the following scenarios, the Council modified two types of assumptions. The first dealt with the level of constraint to development of thermal resources that might be encountered in the region. To meet load under the medium-high and high demand scenarios, the Council projects that significant amounts of new large thermal resources would be required. There are significant questions concerning the feasibility of developing this amount of new thermal resource. To address this question, the Council evaluated the impact of increasing delays or constraints to construction above and beyond that embodied in the resource portfolio. The response to these constraints typically was expressed through a change in the resource development order from the base-case portfolio.

The other type of assumption dealt with an attribute or outcome of some aspect of the future over which we have little control. It is simply an outcome of an uncertain event. An example would be a large unexpected change in fuel prices. The following scenarios and portfolio attributes generally change one type of assumption or the other. However, the fuel price sensitivities discussed below change both types of assumption. Instead of attempting to predict the likelihood of these scenarios, the Council focused primarily on plausible conditions under which the region's energy future could be changed. Table 10-A-1 summarizes the alternative future portfolios examined in this process.

Table 10–A–1
Alternative Resource Portfolios

Scenario	Thermal Constraints	Resource Emphasis	Other Events	Relative Cost (Present Value millions $)	Relative Risk (Present Value millions $)
1	Base Case Assumptions	Least Cost	Base Case Assumptions	0	0
2			60% Conservation Penetration	1,560	470
3			Lose 730 MW of Existing Resource	1,580	560
4			25% Carbon Tax on Coal	350	260
5			1,000 MW More Geothermal	-160	-230
6	Slight Delay	Advance Gas Turbines and Cogeneration	Base Case	100	-200
7			High Gas Prices	1,660	-180
8			Low Gas Prices	-400	-380
9	Moderate Delay	Advance Turbines, Cogeneration and Some Renewables	Base Case	300	-150
10	Extended Delay	Advance Turbines, Cogeneration and Most Renewables	Base Case	510	-80
11	Maximum Delay	Conservation, Renewables and High Efficiency Before Large Thermal	Base Case	1,860	-100
12	WNP-1 and WNP-3 Unavailable	All Non-Nuclear	Base Case	300	390
13	Nuclear and Coal Unavailable	All Other Resources Acquired	Base Case	4,900	4,950
14	Concerns with Reliance on Gas	Advance WNP-3, WNP-1 and Coal	Base Case	460	-10
15			High Gas Prices	-160	-40
16			Low Gas Prices	900	130



Base Case

The base-case portfolio for the draft plan sensitivity studies is similar conceptually to the diverse resource supply portfolio described earlier in this chapter. It was the least-cost resource portfolio under the assumptions used in the draft plan. The major differences in this draft base case include less conservation available in the supply curves and the use of pulverized coal as the representative coal technology. Additionally, the draft base case did not force in conservation program energy for the first 10 years. All discretionary conservation programs were scheduled as needed.

The distribution of system cost present values for this portfolio is the basis for comparison for the sensitivity studies that follow. It is shown in Figure 10-A-1. Due to uncertainty, a wide range of variability in costs is exhibited. With low load conditions, few new resources are needed. With favorable water conditions, costs could be as low as $10 billion. At the other end of the spectrum, if loads grow quickly and large quantities of very expensive resources are secured, or the region frequently experiences poor water conditions, the costs could be as high as $100 billion. The expected value of this distribution is about $50 billion.

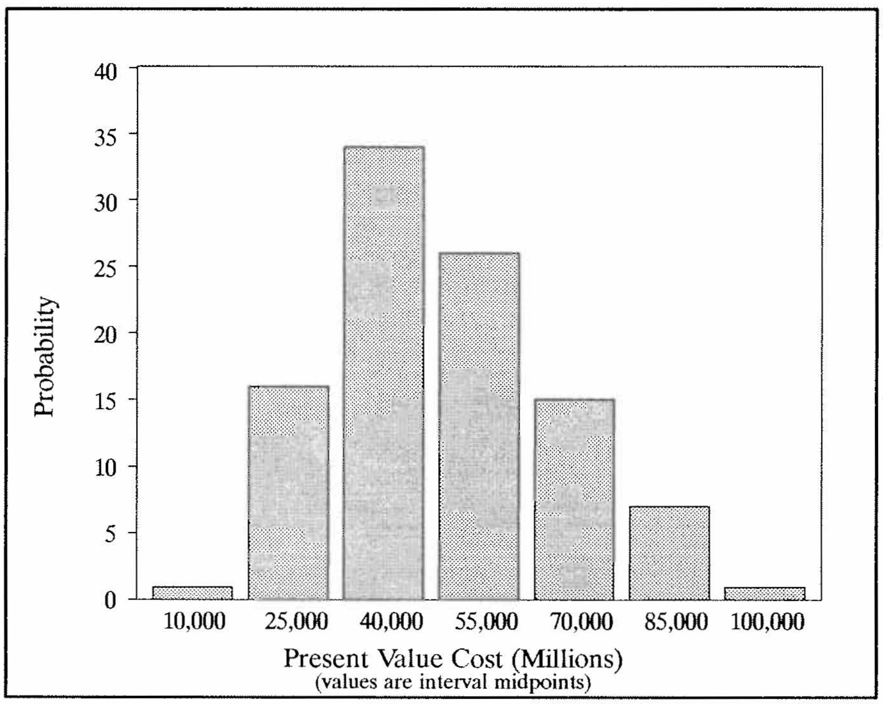
60-Percent Penetration for Conservation

The first draft sensitivity study addressed the question, "What if conservation programs are not as effective as the Council assumes?" Obviously, if conservation is not as effective, other resources are needed sooner. In looking at this sensitivity, it was apparent that if conservation programs achieve only 60-percent penetration of each market sector, instead of the 85 percent assumed in the base case, significant amounts of additional generating resources will be needed on an accelerated schedule. The cost impacts of a failure to acquire 85 percent of the conservation were estimated to be $1.6 billion in present value greater than in the draft base-case resource portfolio.[1] This value is the expected value of a distribution of cost impacts that ranges from $900 million to $2.7 billion (see Figure 10-A-2). Failure of the region to achieve a high penetration rate of cost-effective conservation measures throughout the Northwest economy will be very costly. At the

1. This draft plan scenario is similar to that of the final plan Portfolio 3, the "less conservation achievable" portfolio described earlier in this chapter. That portfolio showed an increase in cost of $2.3 billion over its base case, as opposed to the $1.6 billion stated here. The difference stems from two main factors. The final plan has more conservation available, so a reduction in achievability requires more replacement energy. Second, the final plan uses coal gasification for a coal technology, which is cleaner, but more expensive, than the pulverized coal technology assumptions used in the draft plan.

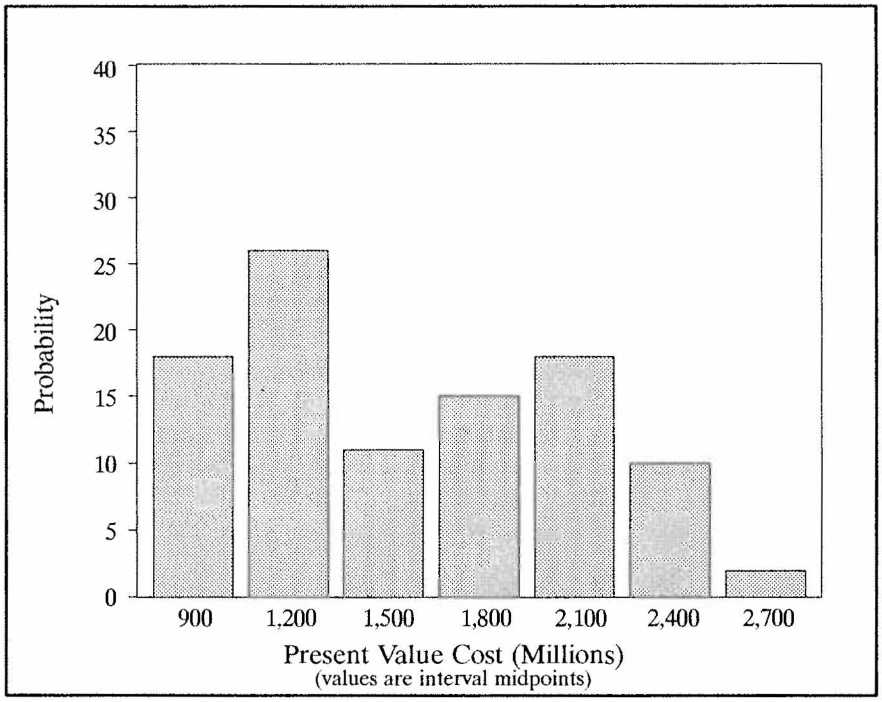
Range of Costs

Figure 10-A-1
System Cost Distribution



Cost Impacts

Figure 10-A-2
60-Percent Conservation Penetration



same time, if the Council's estimates of conservation savings cannot be achieved, alternative resources need to be available to maintain a reliable power system.

Loss of an Existing Resource

Questions have been asked about the effect of the potential loss of an existing system resource. To evaluate this event, the Council assumed that a 730 average megawatt thermal resource in the region suddenly was shut down. The cost impact of losing this amount of energy from the existing power system was estimated to be $1.6 billion. The distribution of cost impacts is shown in Figure 10-A-3. Loss of significant amounts of energy from the existing power system is likely to be very expensive to replace, and a significant amount of lead time will be needed to develop the resources that would replace the loss. The ultimate requirements for additional resource acquisition depend on the load scenario encountered, but the probability of need for high cost renewables and large thermal resources increases significantly over the base case.

25-Percent Coal Tax

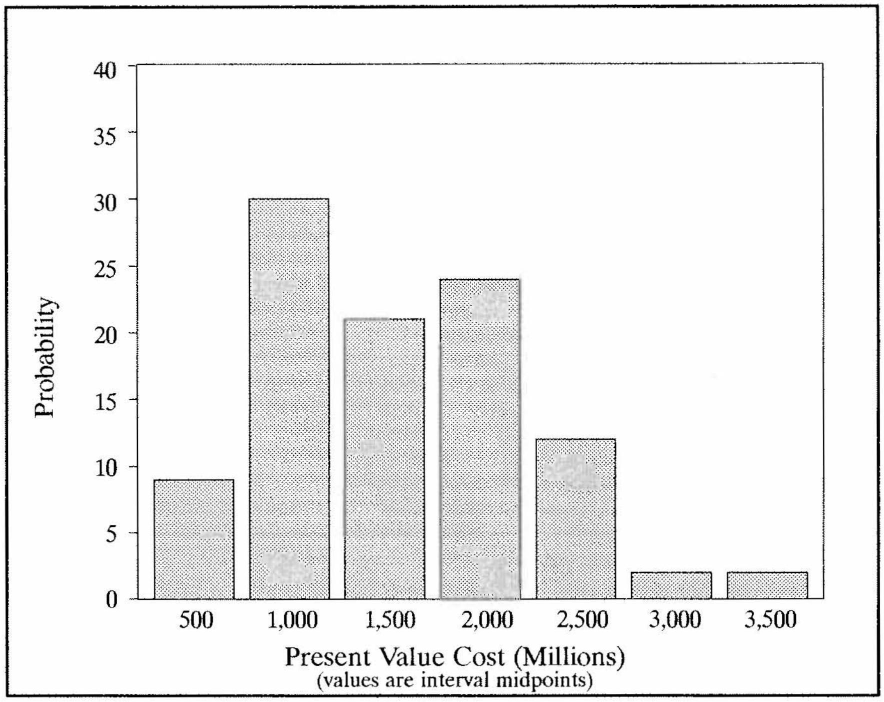
The Council also looked at the cost impacts on the resource portfolio of a 25-percent increase in the cost of coal due to a carbon tax. This tax would affect all coal-fired resources and would, therefore, increase the cost of the fuel component of the energy production from these facilities. The draft resource portfolio incorporated almost 5,000 megawatts of available coal, which would be needed in high-load cases. In these cases, the cost of fuel for most of these plants would be increased. This sensitivity study showed that the expected cost of the region's portfolio would increase by $350 million if there were a 25-percent coal tax (see Figure 10-A-4).

1,000 Megawatts of Geothermal

The Council incorporated 300 megawatts of geothermal resources in the base-case resource portfolio. Many people have argued that the geothermal resource in the Cascade Mountains is significantly larger. The Council evaluated the impact of confirmation of an additional 1,000 megawatts of geothermal energy through the demonstration projects. Cost estimates used for this additional energy were the same as that used for the commercial projects in the base portfolio. This sensitivity study reduced the costs of the base portfolio by $163 million (see Figure 10-A-5). It also produced a moderate reduction in the probability of need for the higher cost coal plants.

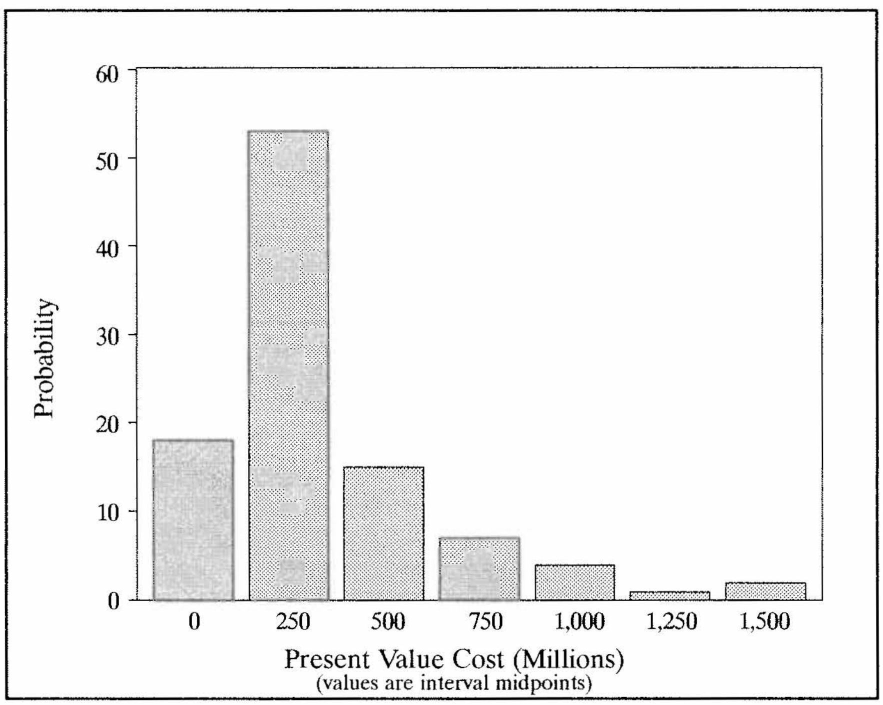
Cost Impacts

Figure 10-A-3
Losing an Existing Resource



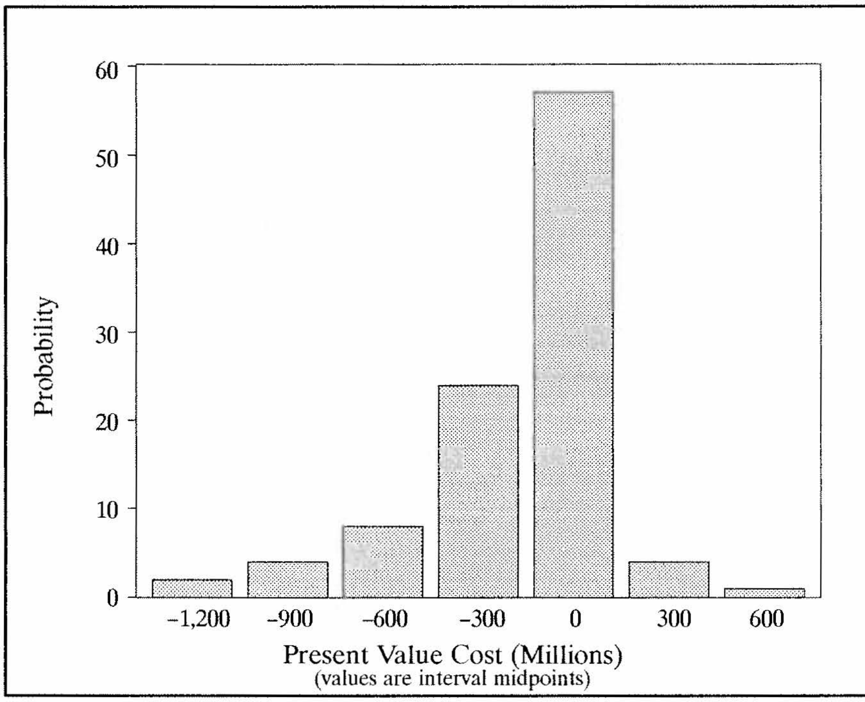
Cost Impacts

Figure 10-A-4
Carbon Tax on Coal



Cost Impacts

Figure 10-A-5
Increased Geothermal Supply



Slight Thermal Delay

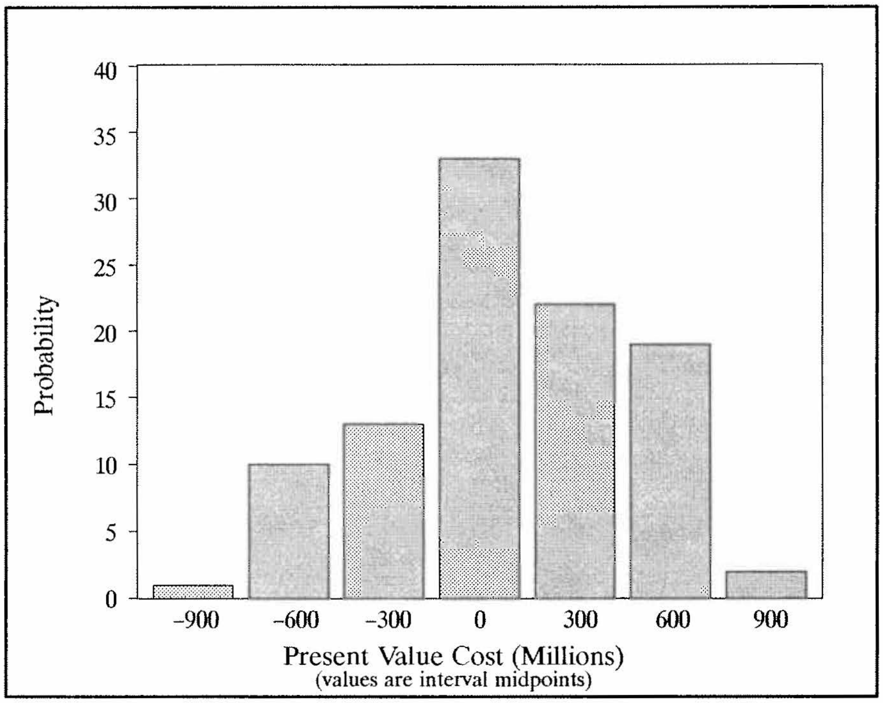
This scenario assumes that problems continue with resolving the barriers to completing WNP-1 and WNP-3. Because of delays in the availability of these power plants, higher cost gas-fired cogeneration and hydrofirming resources need to be moved up to displace the need for WNP-1 and WNP-3. The acceleration of these resources and the displacement of the plants to a later location in the resource portfolio increases the expected costs for the region of this resource portfolio by about $100 million. The distribution of the cost differences is shown in Figure 10-A-6. As a fallout of this portfolio, the region becomes more dependent on gas-fired technologies. This increased dependence on gas exposes the region to higher levels of economic risk if gas prices escalate quickly or if natural gas availability becomes a problem. A further variation of this portfolio examined the impact of rapidly escalating natural gas prices at rates comparable to the Council's highest gas price escalation rate. If this occurred, the cost to the region is expected to be significantly higher, about $1.66 billion over the base case. Alternatively, if this strategy were pursued and gas prices escalated at rates near the Council's low natural gas price forecast, the region would be better off by about $400 million over the base resource portfolio strategy.

Moderate Thermal Delay

If the difficulties with removing the barriers to completing WNP-1 and WNP-3 continue, then additional resources need to be moved up to meet regional energy needs. These resources include the moderately expensive hydropower blocks, geothermal and wind, in addition to the turbines and cogeneration moved up in the previous portfolio. Moving up these resources in the resource portfolio increases the expected costs of the resource portfolio by about $300 million. While the cost increase is moderate, the Council was concerned with the availability and predictability of these resources. If these resources are not available to displace the need for WNP-1 and WNP-3, regional costs could be significantly higher. Figure 10-A-7 shows the cost distribution for this portfolio.

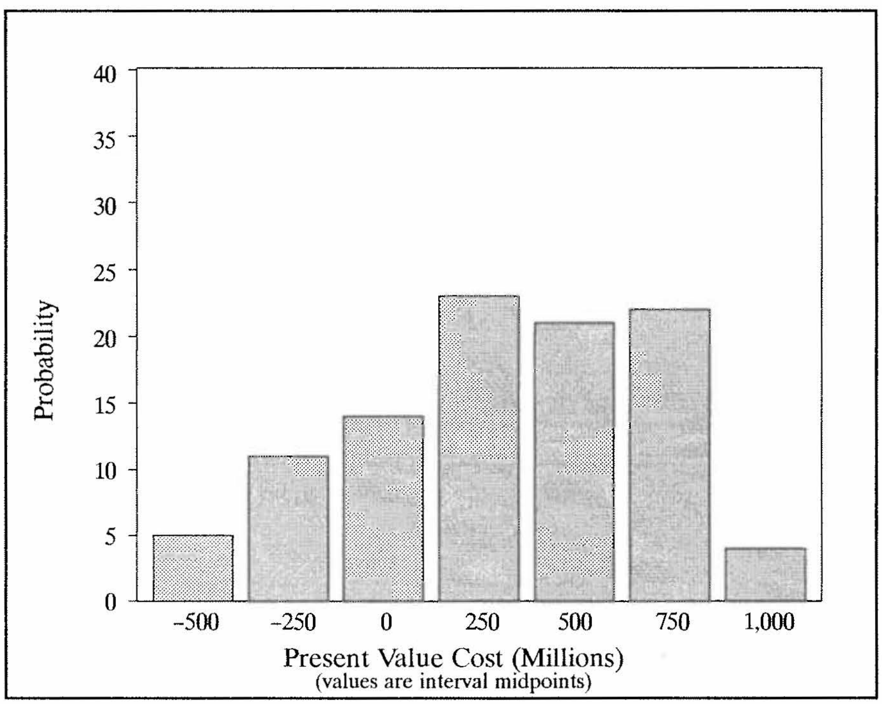
Cost Impacts

Figure 10-A-6
Slight Thermal Delay



Cost Impacts

Figure 10-A-7
Moderate Thermal Delay



Extended Thermal Delay

If, in addition to the delays surrounding the WNP-1 and WNP-3 plants, the region also has significant difficulty in siting, licensing and constructing new coal-fired resources, there is a need for moving even higher-cost resources forward in the region's resource portfolio. In addition, the region would need to accelerate the most expensive blocks of cogeneration, small hydro and wind. As shown by Figure 10-A-8, this scenario is expected to cost about $500 million more than the base resource portfolio. Even with all of these changes, there is still a significant probability of need for actions on large thermal before the year 2000.

Maximum Thermal Delay

The Council looked at a portfolio that ignored the cost-effectiveness of portfolio resources and focused efforts on delaying thermal resource decisions as long as possible. To do this, the Council assumed that hydropower, geothermal and wind resources are developed as needed to meet the region's load growth. Following these resources, the gas-fired technologies are acquired, primarily cogeneration and the use of combustion turbines to back up nonfirm. These resources have shorter lead times and are smaller than the larger thermal power stations that follow. Finally, if loads continue to grow, WNP-1 and WNP-3 and the 5,000 megawatts of available coal are developed. This resource portfolio has an expected cost increase over the base portfolio of about $1.8 billion (see Figure 10-A-9). Most of this impact is due to the fact that higher-cost resources are acquired much earlier. While thermal resources could be delayed if loads grow at above the medium load scenario, thermal resources still are likely to be needed before 2010.

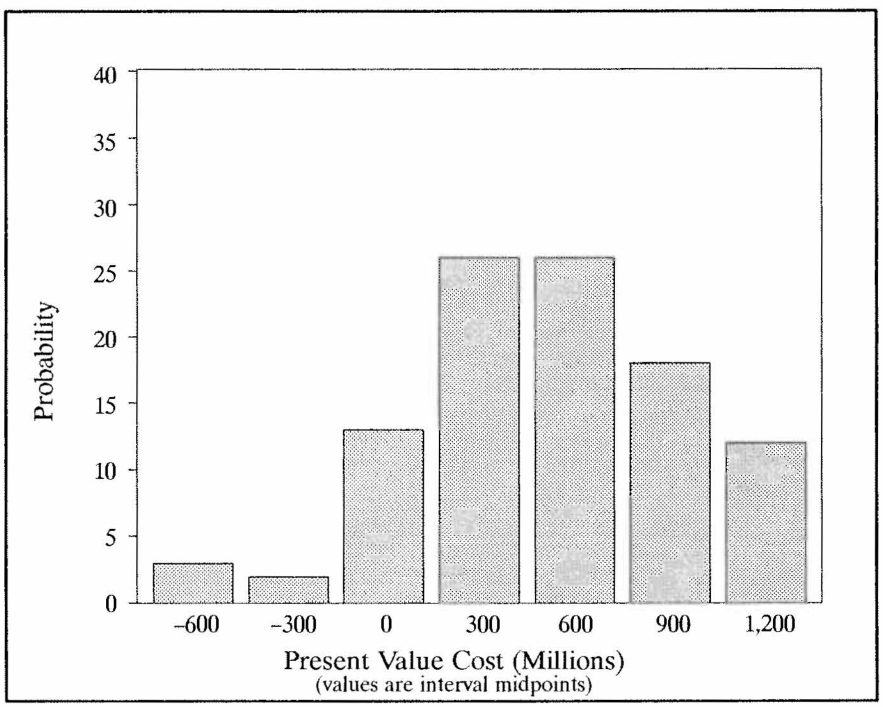
Loss of WNP-1 and WNP-3

The Council also looked at the impacts of WNP-1 and WNP-3 being not available. In evaluating this sensitivity study, WNP-1 and WNP-3 were removed from the Council's resource portfolio. If these resources are lost to the region, the cost of the resource portfolio increased by about $300 million[2] (see Figure 10-A-10). Other thermal resources need to move forward in time, in order to displace the 1,600 megawatts that could be available from WNP-1 and WNP-3.

2. A separate study on the value of WNP-1 and WNP-3 was not performed for the final plan. However, if the study were done, it is likely that the expected cost of losing WNP-1 and WNP-3 as potential resources would be higher than the $300 million stated here. This is due to the more expensive coal gasification technology assumptions used in the final plan.

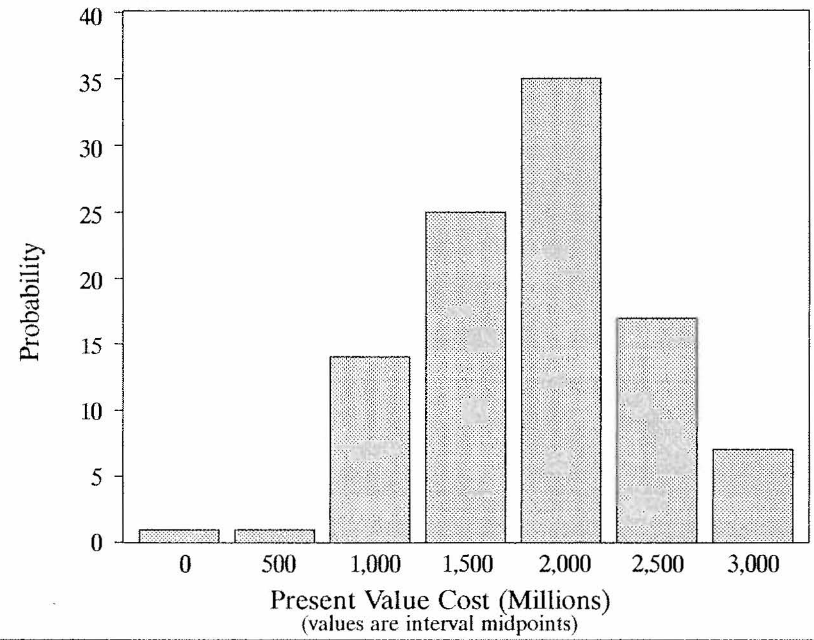
Cost Impacts

Figure 10-A-8
Extended Thermal Delay



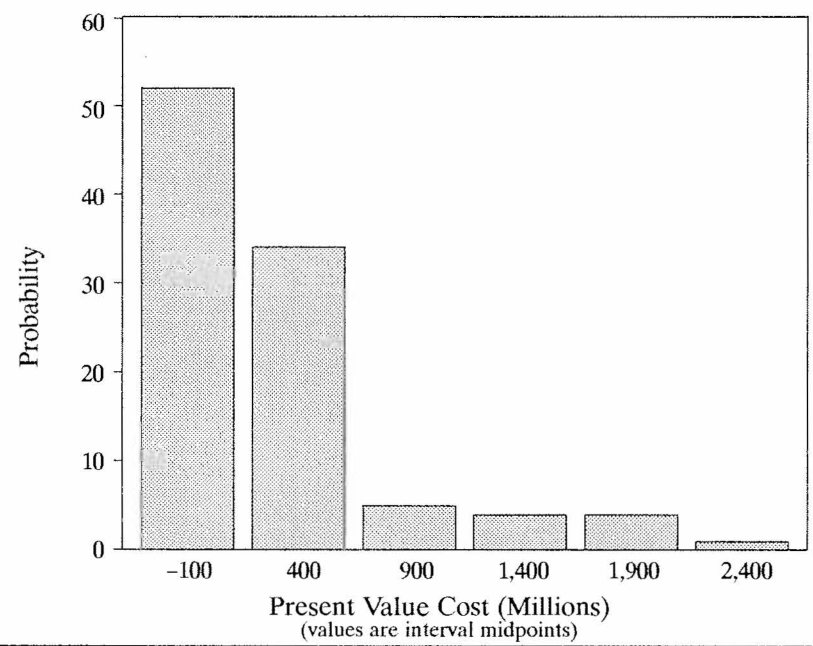
Cost Impacts

Figure 10-A-9
Maximum Thermal Delay



Cost Impacts

Figure 10-A-10
WNP-1 and WNP-3 Unavailable



Concerns with Reliance on Gas

If there are perceptions that heavy reliance on combustion turbines and gas-fired cogeneration is too risky a path, due to concerns about long-term fuel price or availability, there could be significant resistance to development of these resources. One alternative would be to rely more heavily on nuclear and coal resources. If WNP-3, WNP-1 and the first block of coal are moved ahead of the first blocks of turbines and cogeneration, the expected cost under the base-case fuel price assumptions is about $460 million. However, if large thermal resources were emphasized over gas-fired resources and high natural gas prices were to materialize, this strategy produces a cost improvement over the base portfolio strategy of $160 million. Alternatively, if low gas prices occur, this strategy produces an expected value that's $900 million more expensive than the base portfolio where gas-fired resources have a higher priority.

Cost versus Risk Assessment for the Draft Plan Portfolio Selection

Extensive research has been conducted regarding the theory and practice of selecting financial investment portfolios. This research has identified two primary attributes of alternative portfolios. The first, and most obvious, is the expected rate of return that can be achieved from a portfolio containing a selection of financial investments. In the context of the Council's planning, the surrogate for this attribute is the expected cost of constructing, operating and maintaining the existing and future electrical resources needed to meet the region's energy needs. Where financial portfolio theory strives to maximize the expected return, the Council's resource portfolio strives to minimize the expected cost.

The second attribute from financial portfolio theory is the variability of the return expected. Variability is normally characterized in a statistic called the standard deviation or the variance and is a measure of the risk inherent in the portfolio. The resource portfolio exhibits a high level of variability in costs. This was shown in Figure 10-A-1, which illustrates the system cost probability density function for the Council's resource portfolio. In this figure the most likely cost of the region's portfolio over the next 70 years is $40 billion (i.e., most probable outcome). Under extremely low load conditions, very few resources are built, and, in combination with good water years, the cost could be as low as $10 billion. At the other end of the spectrum, if loads grow quickly, and large quantities of very expensive resources are secured, or the region frequently experiences poor water conditions, the costs could be as high as $100 billion. The expected, or average, value from this distribution is about $50 billion.

When the Council compares two alternative resource portfolios, the difference between the expected values is normally what is expressed as the cost or benefit of moving from one portfolio to another. The standard deviation is that distance above and below the expected value that normally will incorporate approximately 68 percent of all cost outcomes.

In choosing the base resource portfolio, the Council looks at both the expected costs and the standard deviations from a variety of alternative resource portfolios. By balancing cost and risk, the Council attempts to identify the "best" resource portfolio.

In terms of the Council's planning, the best resource portfolio has the lowest expected cost while also providing the highest degree of reliability possible. A difficult part of selecting a resource portfolio is that it may be easy to achieve a highly certain cost by undertaking very high-cost actions. For example, if the region were to acquire significant amounts of very expensive non-displaceable power, the region's resource portfolio would have a high expected cost, but also a high degree of certainty. Another example might be that a highly certain resource portfolio can be achieved by purchasing extreme amounts of insurance against all possible uncertainties. In either case, these portfolios are judged not to be preferable to a more balanced, lower cost resource portfolio that incorporates some degree of risk.

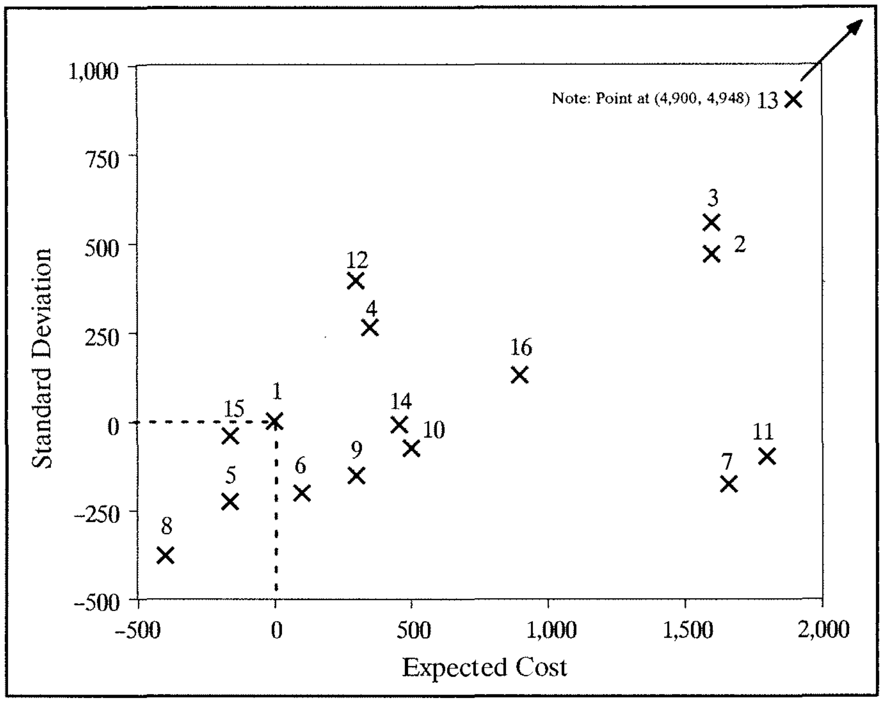
In choosing between two alternative resource portfolios, the Council prefers a portfolio that has lower expected cost and lower risk. In portfolio theory, this relationship is called "stochastic dominance." Stochastic dominance occurs between two alternative portfolios when one portfolio has both a lower expected cost and a lower standard deviation than the alternative.

Table 10-A-1 illustrates some of the various scenarios that the Council looked at when selecting a base-case resource portfolio for its draft plan. The details of these scenarios were discussed previously, but it is important to note that some of these scenarios are sensitivity studies rather than complete scenarios. As sensitivity studies, one key, but uncertain, parameter was set at a particular value. This helps the Council to understand how sensitive the resource portfolio is to a specific parameter. Because it is not possible for the Council or the region to pre-ordain the desired level of these parameters, these sensitivity studies are not physically achievable. On the other hand, some of the resource scenarios involved alternative priorities for resource development. These are choices that the region can make regarding how the future resource mix will be modified or changed over the next 20 years.

Figure 10-A-11 illustrates the trade-off between the expected cost of each of these scenarios and the standard deviations associated with those scenarios. Because the standard deviations represent the amount of dispersion around the expected value, they are an indication of the degree of risk. The numbered points on this graph correspond to the scenario numbers from Table 10-A-1.

Alternative Portfolios

Figure 10-A-11
Cost/Risk Analysis



Portfolio 1 is the base-case resource portfolio that the Council uses as the planning base of this plan. Fifteen alternative portfolios were evaluated and plotted on Figure 10-A-11 to illustrate the trade-offs between risk and expected cost. The vertical axis of the figure represents the standard deviations of the various resource portfolios. Larger amounts of standard deviation indicate a higher degree of risk in the resource portfolio. The horizontal axis in the figure illustrates the relative expected cost of the resource portfolio. Both the standard deviation and expected cost are relative estimates of the change in these two attributes when each portfolio is measured with respect to the base case. For this reason, the portfolio labeled number 1 is by definition the resource portfolio with no expected cost and no standard deviation in this plot. In reality, the base-case resource portfolio has an expected cost of $50 billion and a standard deviation of $17 billion.

The base-case resource portfolio number 1 is clearly preferable in terms of cost and risk to any portfolio that is in the upper right quadrant of the diagram. Any portfolio that falls here has both a higher expected cost and a higher associated risk than the base-case portfolio. The base-case portfolio is said to be stochastically dominant over these resource portfolios. For resource portfolios that have a significantly higher expected cost and only slightly different standard deviations (for example, portfolios number 7, 11, 14 and 10), the base-case resource portfolio is judged by the Council to be preferable. The resource portfolios numbered 8, 5 and 15 appear to have both superior cost and risk characteristics to the base-case portfolio, while Portfolios number 2 and 8 have higher costs, but reduced risk. It appears that these portfolios are potential competitors with the base portfolio. A discussion of these competing portfolios follows.

Portfolios 15 and 8 represent sensitivity studies around future gas prices. In Portfolio 15, gas prices are assumed to be high, but the region has advanced the development of WNP-1 and WNP-3 and coal instead of building a large amount of gas-fired generation. In Portfolio 8, future gas prices are assumed to be low and the region has decided to undertake the development of a significant amount of gas-fired generation. In these two portfolios, the future gas prices are assumed to be known at either high or low levels. These obviously are unattainable futures because the future price of natural gas is inherently uncertain.

Portfolio 5 illustrates how the region's resource portfolio would be improved through a successful geothermal demonstration program. It assumes the demonstration program confirms an additional 1,000 megawatts of cost-effective geothermal energy. This resource portfolio is stochastically dominant over the base-case portfolio in that it has a lower expected cost and a lower standard deviation (less risk). However, as with fuel prices, it is not a certain future. There is some probability that an additional geothermal resource will not prove out at costs competitive with other portfolio resources. Portfolio 5 illustrates the importance of undertaking a research and development effort on new geothermal resources in the region.

Portfolios 6 and 9 are potential competitors with the base-case resource portfolio. These two portfolios offer the trade-off between a higher expected cost in exchange for a lower risk (standard deviation). Portfolio 6 delays WNP-1 and WNP-3 and the development of new coal-fired power plants by advancing the development of cogeneration and gas-fired combustion turbines. In fact, this resource portfolio may not be lower risk than the base case. These resource portfolios, like any of the resource portfolios analyzed here, cannot take into account all possible uncertainty or risk. In this case, future uncertainty in gas prices was not analyzed or incorporated into the estimate of the standard deviation for the resource portfolio. That is precisely why the Council looked at the sensitivity studies to see the impacts of rapidly escalating gas prices. Therefore, Portfolio 6 offers some potential benefits; however, the analysis supporting Portfolio 6 may not incorporate one of the more important uncertainties.

Portfolio 9 offers a more complex trade-off with the base case. In this case, the costs are significantly higher than the base case, although within the range of being potentially viable. Portfolio 9 involves advancing the development of hydropower, geothermal and wind resources in an attempt to defer thermal power plant development as long as possible. Because of the potential advantages in terms of reducing risk that this portfolio offers, the Council designed special action items to focus on the need to better understand the cost and availability of these renewable resources. If these resources can be confirmed and their cost of development reduced, then it is possible that the risk reduction benefits of Portfolio 9 can be achieved without significantly increasing the expected cost of the resource portfolio.

APPENDIX 10-B

DETERMINISTIC RESOURCE SCHEDULES FOR THE ALTERNATIVE RESOURCE PORTFOLIOS

Study ID :5-APR-91 13:20:10
Study Title:DIVERSE SUPPLY SCENARIO - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3151	3260	3326	3414	3523	3631	3745	3846	3943	4045	4148	4254	4357	4468	4594	4718	4835	4955	5080	5206
Observed Rate	3.47%	2.02%	2.66%	3.17%	3.07%	3.15%	2.69%	2.53%	2.59%	2.55%	2.54%	2.43%	2.55%	2.80%	2.71%	2.48%	2.47%	2.52%	2.48%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2489	-2749	-2944	-2905	-3101	-3295	-3471	-3441	-3607	-3781	-3921	-4064	-4222	-4392	-4561	-4616	-4728	-4903	-5085	-5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	10	17	24	32	39	47	57	66	76	86	96	102	104	106	108
New Commercial 1	0	0	1	3	6	9	13	16	20	24	27	31	35	38	42	46	50	54	58	63
Commercial R&R 1	0	3	5	8	10	13	15	18	20	23	25	28	30	33	36	38	41	43	46	48
New SF Res 1	0	1	2	3	6	9	13	16	19	23	26	29	33	36	40	43	46	50	53	57
New MF Res 1	0	0	0	0	0	1	1	1	1	2	2	2	2	2	3	3	3	3	4	4
New Manuf Housing 1	0	0	1	2	3	4	6	8	9	11	13	15	16	18	20	22	23	25	27	29
New Res Light 1	0	0	1	1	2	4	5	7	8	9	11	12	13	15	16	18	19	20	22	23
Wtr Htr Heat Pumps	0	0	0	0	1	3	4	6	8	10	12	14	17	19	21	23	25	27	29	31
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	1	2	4	5	6	8	9	10	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	192	209	243	339	395	461	529	644	708	777	838	895	953	1010	1070	1128	1181	1229	1282	1334
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	60	75	75	75	75	75	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	357	357	714	714	714	714	714	714	714	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	4	7	11	11	14	14	14	14	14	14	14	14	14	14
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	20	60	80	80	80	80	80	80	80	80	80	80	80	80	80
Cogen 2	0	0	0	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8
WNP 1	0	0	0	0	0	0	0	0	0	0	0	818	818	818	818	818	818	818	818	818
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	714	714	1071	1071
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	8
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16	16	64	64	80
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	15	36	71	135	543	1419	1776	1779	2597	2597	2597	2954	2970	3327	3383	3740	3756
Total Firm Resources	5147	4921	4748	4888	4816	4768	4851	5536	6269	6474	6395	7123	6953	6770	7023	7049	7353	7289	7520	7531
Load/Resource Balance	-340	-653	-914	-883	-1062	-1217	-1248	-663	-27	77	-80	569	320	27	155	56	243	60	166	51

Study ID :5-APR-91 13:20:10
Study Title:DIVERSE SUPPLY SCENARIO - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9642	10059	10381	10709	11061	11407	11751	12045	12332	12636	12932	13232	13524	13842	14203	14557	14898	15246	15608	15970
Observed Rate	4.33%	3.20%	3.16%	3.29%	3.13%	3.01%	2.50%	2.39%	2.46%	2.34%	2.32%	2.21%	2.36%	2.60%	2.50%	2.34%	2.34%	2.37%	2.32%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	8	24	41	60	79	98	118	138	161	186	211	235	250	257	262	265
New Commercial 1	0	3	6	16	34	55	77	100	123	147	170	193	217	242	268	292	318	344	371	398
Commercial R&R 1	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95
New SF Res 1	0	1	3	6	10	16	22	28	34	40	47	53	59	66	72	79	85	91	97	104
New MF Res 1	0	0	0	1	1	2	2	3	4	5	5	6	7	7	8	9	10	10	11	12
New Manuf Housing 1	0	1	2	4	7	12	16	20	25	30	35	39	44	49	53	58	63	67	72	76
New Res Light 1	0	0	1	2	4	6	8	9	11	13	15	17	19	22	24	26	27	29	31	33
Wtr Htr Heat Pumps	0	1	2	4	7	11	15	19	24	29	34	38	43	48	53	58	62	67	72	76
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96	108
Subtotal	0	26	77	154	254	375	496	617	744	871	991	1109	1234	1360	1487	1614	1730	1837	1946	2051
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	87	87	87	87	87
Thermal Eff Imp	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	656	824	960	960	960	960	960	960	960	960	960
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	107	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	597	895	895	1194	1492	1790	1790	1790	1790	1790	1790
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16	248	320	456	456	456
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	262	262	523	785
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	262
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	50	60	110	357	603	1232	1662	2986	3485	3648	3986	4309	4615	4854	5188	5332	5593	6124
Total Firm Resources	9519	9555	9654	9501	9579	9872	10074	10661	11098	12429	12996	13230	13666	14060	14448	14653	15051	15312	15701	16100
Load/Resource Balance	-123	-505	-726	-1208	-1482	-1536	-1677	-1383	-1235	-207	65	-2	142	218	246	95	153	66	93	131

Study ID :5-APR-91 13:20:10
Study Title:DIVERSE SUPPLY SCENARIO - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4827	5043	5206	5373	5553	5730	5905	6055	6208	6369	6521	6675	6825	6989	7173	7355	7535	7719	7911	8103
Observed Rate	4.49%	3.23%	3.19%	3.35%	3.19%	3.06%	2.54%	2.52%	2.59%	2.39%	2.37%	2.24%	2.39%	2.64%	2.54%	2.45%	2.45%	2.48%	2.43%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2382	2611	2756	2905	3101	3295	3471	3441	3607	3781	3921	4064	4222	4392	4561	4616	4728	4903	5085	5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	9	16	22	29	36	44	52	61	70	79	88	94	96	98	99
New Commercial 1	0	1	2	5	10	15	21	27	33	40	45	51	58	64	71	77	84	90	97	105
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	3	5	9	12	15	18	21	24	27	30	33	37	40	43	46	49	52
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	4
New Manuf Housing 1	0	0	1	1	3	4	6	7	9	10	12	14	15	17	18	20	22	23	25	26
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	4	6	8	10	12	13	15	17	19	21	23	25	27	29
Subtotal	0	1	4	9	22	40	60	78	98	118	139	159	181	203	226	249	269	283	299	315
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4827	5045	5211	5382	5575	5770	5964	5952	6116	6288	6453	6621	6785	6962	7160	7361	7554	7745	7943	8148
Load/Resource Balance	0	1	4	10	22	40	59	-103	-92	-81	-68	-54	-41	-27	-13	6	19	26	32	45

Study ID :5-APR-91 13:20:10
Study Title:DIVERSE SUPPLY SCENARIO - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17619	18363	18913	19496	20136	20768	21401	21946	22483	23050	23601	24161	24706	25299	25970	26631	27269	27920	28598	29278
Observed Rate	4.22%	3.00%	3.08%	3.29%	3.14%	3.05%	2.54%	2.45%	2.52%	2.39%	2.37%	2.26%	2.40%	2.65%	2.55%	2.40%	2.39%	2.43%	2.38%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	14	43	74	106	140	173	209	247	288	332	376	419	446	457	466	472
New Commercial 1	0	4	9	24	50	79	111	143	176	211	242	275	310	344	381	415	452	488	526	566
Commercial R&R 1	0	8	15	23	30	38	45	53	60	68	75	83	90	98	106	113	121	128	136	143
New SF Res 1	0	2	6	12	21	34	47	59	71	84	97	109	122	135	149	162	174	187	199	213
New MF Res 1	0	0	0	1	1	4	4	5	6	8	9	10	11	11	13	15	16	16	18	20
New Manuf Housing 1	0	1	4	7	13	20	28	35	43	51	60	68	75	84	91	100	108	115	124	131
New Res Light 1	0	0	2	3	6	10	13	16	19	22	26	29	32	37	40	44	46	49	53	56
Wtr Htr Heat Pumps	0	1	2	4	9	16	23	31	40	49	58	65	75	84	93	102	110	119	128	136
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	308	326
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	212	224
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	16	17	19	20	21	23	24	25	26
High Cost Block	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96	110
Subtotal	192	236	324	502	671	876	1085	1339	1550	1766	1968	2163	2368	2573	2783	2991	3180	3349	3527	3700
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	110	110	110	110	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	714	714	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	15	29	44	54	65	72	79	86	94	101	101	101	101	101
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	50	50	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	180	340	480	500	500	500	500	500	500	500	500	500	500	500	500
Cogen 2	0	0	0	0	0	0	0	49	57	57	57	57	57	57	57	57	57	57	57	57
WNP 1	0	0	0	0	0	0	0	0	0	0	0	818	818	818	818	818	818	818	818	818
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	714	714	1071	1071	1428	1428
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	31	31	38
Cogen 3	0	0	0	0	0	0	0	0	328	656	824	960	960	960	960	976	976	1024	1024	1040
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	107	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	597	895	895	1194	1492	1790	1790	1790	1790	1790	1790
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	16	16	16	248	320	456	456	456
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	262	262	523	785
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	262
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	50	75	146	428	738	1775	3081	4762	5264	6245	6583	6906	7569	7824	8515	8715	9333	9880
Total Firm Resources	19493	19521	19613	19771	19970	20410	20890	22150	23483	25191	25844	26974	27403	27792	28632	29063	29958	30347	31164	31779
Load/Resource Balance	-462	-1156	-1636	-2081	-2522	-2713	-2866	-2149	-1354	-211	-83	512	422	218	388	157	415	152	291	226

Study ID :5-APR-91 13:19:47
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3080	3141	3175	3229	3298	3370	3443	3514	3582	3647	3715	3787	3858	3935	4020	4107	4191	4276	4367	4456
Observed Rate	1.98%	1.09%	1.68%	2.14%	2.18%	2.18%	2.05%	1.93%	1.83%	1.85%	1.95%	1.87%	2.00%	2.15%	2.17%	2.04%	2.03%	2.12%	2.04%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2367	-2536	-2673	-2571	-2693	-2817	-2927	-2880	-2999	-3113	-3192	-3278	-3389	-3511	-3621	-3622	-3675	-3790	-3912	-3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	9	15	21	28	34	42	50	59	67	75	83	89	91	92	93
New Commercial 1	0	0	1	2	4	7	9	12	15	18	21	24	27	30	34	37	40	44	47	51
Commercial R&R 1	0	3	5	8	11	13	16	19	22	24	27	30	32	35	38	40	43	46	49	51
New SF Res 1	0	0	1	2	4	5	7	9	11	13	15	17	19	21	24	26	28	30	32	34
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	26	28	30	32
New Res Light 1	0	0	0	1	2	3	4	5	5	6	7	8	9	10	11	12	13	14	15	16
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	6	7	8	10	11	13	14	16	17	18	20	21
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	37	37	39	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	78	84	91	100	110	119	128	138	147	156
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	8	9	10	10	11	12	12
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	46	46	49	54	59	64	70	75	80	85
Industrial 2	0	1	4	10	16	23	29	35	41	48	53	57	62	68	75	81	88	94	101	107
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	77	84	92	102	112	121	131	141	150	160
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	64	144	241	337	392	453	517	627	689	751	803	841	887	940	995	1046	1096	1143	1188	1233
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	60	75	75	75	75	75	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357	714	714	714	714	714	714	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	0	0	7	11	11	14	14	14	14	14	14	14	18	18
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	60
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	21	36	51	71	91	459	463	820	823	823	1691	1691	1691	1691	1691	1735	1755
Total Firm Resources	5141	5070	5018	5227	5220	5217	5319	5629	5897	5805	6127	6079	5946	6676	6626	6683	6684	6620	6593	6669
Load/Resource Balance	-221	-301	-394	-246	-306	-365	-335	-96	105	-53	216	108	-82	570	436	405	323	174	57	44

Study ID :5-APR-91 13:19:47
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9398	9637	9839	10036	10240	10450	10660	10858	11048	11228	11400	11587	11780	11997	12234	12478	12706	12940	13187	13427
Observed Rate	2.54%	2.09%	2.00%	2.04%	2.04%	2.01%	1.86%	1.75%	1.63%	1.53%	1.63%	1.67%	1.84%	1.98%	1.99%	1.83%	1.84%	1.91%	1.82%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	7	21	36	53	69	86	104	123	142	163	184	204	217	222	226	228
New Commercial 1	0	2	5	11	23	40	57	75	93	112	131	151	171	192	214	234	256	278	300	324
Commercial R&R 1	0	5	11	16	21	27	32	37	43	48	53	59	64	69	75	80	85	91	96	101
New SF Res 1	0	0	2	3	6	9	13	16	20	24	27	31	35	39	43	47	51	54	58	62
New MF Res 1	0	0	0	1	1	2	2	3	3	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	5	8	13	17	22	27	33	38	43	49	54	59	65	70	75	80	85
New Res Light 1	0	0	1	1	3	4	5	7	8	9	11	12	14	15	17	18	19	21	22	23
Wtr Htr Heat Pumps	0	0	1	3	5	7	10	13	16	19	23	26	29	33	36	39	43	46	49	52
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Subtotal	0	23	75	146	237	347	457	569	683	799	906	1008	1110	1211	1315	1417	1513	1599	1685	1772
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	83	83	83	83	83
Thermal Eff Imp	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	416	520	624	768	912	960	960	960	960	960	960
Wind 1	0	0	0	0	0	0	0	0	17	17	17	17	17	17	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	0	0	105	105	105	105	105	105	175	175	245	245	245	280
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	15	26	33	41	55	66	77	89	100
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298	298	597	597	895
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32	32	72	72	72	96
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	60	110	240	390	934	1437	1909	2031	2166	2333	2498	2676	2991	3112	3430	3442	3817
Total Firm Resources	9519	9554	9601	9493	9561	9727	9822	10313	10811	11279	11457	11645	11889	12101	12336	12595	12758	13171	13288	13514
Load/Resource Balance	121	-83	-237	-542	-679	-723	-837	-545	-237	51	57	59	108	104	102	117	52	231	101	87

Study ID :5-APR-91 13:19:47
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4705	4830	4935	5038	5144	5252	5361	5464	5568	5667	5754	5849	5949	6061	6183	6309	6427	6548	6676	6801
Observed Rate	2.67%	2.18%	2.09%	2.10%	2.11%	2.07%	1.92%	1.89%	1.78%	1.54%	1.64%	1.71%	1.88%	2.02%	2.04%	1.87%	1.88%	1.96%	1.86%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2260	2398	2485	2571	2693	2817	2927	2880	2999	3113	3192	3278	3389	3511	3621	3622	3675	3790	3912	3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	8	14	20	26	32	39	47	54	62	69	77	82	84	85	85
New Commercial 1	0	0	1	3	7	11	16	20	25	30	35	40	45	51	56	62	67	73	79	85
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	25	27	29	31
New MF Res 1	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	8	10	11	13	15	17	19	21	22	24	26	28	29
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	5	6	8	9	10	12	13	14	16	17	18	20
Subtotal	0	0	3	7	17	31	47	61	77	92	110	129	146	166	183	201	217	230	242	253
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4705	4831	4938	5045	5160	5283	5407	5374	5487	5596	5696	5804	5917	6041	6176	6320	6451	6578	6712	6849
Load/Resource Balance	0	1	3	7	16	31	45	-91	-81	-71	-58	-44	-32	-20	-7	11	24	30	36	49

Study ID :5-APR-91 13:19:47
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17183	17608	17949	18303	18682	19072	19464	19837	20197	20542	20869	21222	21587	21993	22438	22895	23325	23764	24230	24683
Observed Rate	2.47%	1.94%	1.97%	2.07%	2.09%	2.06%	1.91%	1.82%	1.71%	1.59%	1.69%	1.72%	1.88%	2.02%	2.04%	1.88%	1.89%	1.96%	1.87%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	13	38	65	94	123	152	185	220	255	292	328	364	388	397	403	406
New Commercial 1	0	2	7	16	34	58	82	107	133	160	187	215	243	273	304	333	363	395	426	460
Commercial R&R 1	0	8	16	24	32	40	48	56	65	72	80	89	96	104	113	120	128	137	145	152
New SF Res 1	0	0	4	7	13	19	27	33	41	49	56	64	72	80	89	97	104	111	119	127
New MF Res 1	0	0	0	1	1	4	4	5	5	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	9	14	22	30	38	47	56	65	74	84	93	102	111	120	129	138	146
New Res Light 1	0	0	1	2	5	7	9	12	13	15	18	20	23	25	28	30	32	35	37	39
Wtr Htr Heat Pumps	0	0	1	3	7	11	16	21	27	32	39	45	50	58	63	69	76	81	87	93
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	93	96	98	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	157	172	189	207	226	245	263	282	301	319
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	20	22	24	25	27	29	30
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	92	97	105	114	124	134	145	155	164	174
Industrial 2	0	2	8	20	32	46	58	70	82	96	107	117	129	141	155	167	181	193	207	219
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	230	256	283	312	341	370	399	428	456	485
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
Subtotal	64	167	319	490	646	831	1021	1257	1449	1642	1819	1978	2143	2317	2493	2664	2826	2972	3115	3258
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	110	110	110	110	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	357	714	714	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	11	22	40	54	62	72	79	86	94	97	97	97	101	101
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	0	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	460	480
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	416	520	624	768	912	960	960	960	960	960	960
Wind 1	0	0	0	0	0	0	0	0	17	17	17	17	17	17	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	0	0	105	105	105	105	105	105	175	175	245	245	245	280
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	15	26	33	41	55	66	77	89	100
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298	298	597	597	895
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32	32	72	72	72	96
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	81	146	291	461	1025	1896	2372	2851	2989	3156	4189	4367	4682	4803	5121	5177	5572
Total Firm Resources	19365	19455	19558	19765	19942	20227	20548	21317	22195	22680	23281	23528	23751	24817	25137	25597	25892	26370	26593	27032
Load/Resource Balance	-100	-383	-628	-781	-969	-1057	-1127	-731	-213	-73	215	122	-6	654	530	533	398	436	193	179

Study ID :5-APR-91 13:20:33
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3028	3063	3082	3117	3160	3207	3261	3313	3365	3415	3464	3514	3566	3623	3689	3759	3829	3899	3969	4041
Observed Rate	1.16%	0.63%	1.12%	1.39%	1.51%	1.68%	1.60%	1.56%	1.48%	1.42%	1.46%	1.46%	1.62%	1.82%	1.88%	1.87%	1.83%	1.80%	1.80%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2273	-2384	-2489	-2347	-2426	-2510	-2584	-2522	-2606	-2687	-2740	-2795	-2874	-2964	-3043	-3015	-3045	-3135	-3223	-3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	8	14	20	26	33	40	48	56	64	71	79	84	86	87	88
New Commercial 1	0	0	1	1	3	5	7	10	12	14	16	19	21	24	27	29	32	34	37	40
Commercial R&R 1	0	2	5	7	10	12	15	17	19	22	24	27	29	32	34	36	39	41	44	46
New SF Res 1	0	0	1	1	3	4	5	7	8	10	11	13	14	16	17	19	20	22	23	25
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	8	10	12	13	15	17	19	21	23	24	26	28	30
New Res Light 1	0	0	0	1	2	2	3	4	5	6	6	7	8	9	10	11	11	12	13	14
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	6	7	8	9	10	11	12	14	15	16	17
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	152	155
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	104	107
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	49	92	147	203	363	521	676	740	794	845	895	945	994	1045	1091	1133	1174	1208
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	15	30	45	45	60	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	4	4	4	7	7	11	14	14	14	14	14
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	20
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	15	34	49	49	67	87	102	109	466	466	486	486
Total Firm Resources	5171	5094	5009	5185	5205	5225	5438	5788	5833	5787	5801	5792	5711	5621	5613	5705	6084	6043	6022	6092
Load/Resource Balance	-41	-123	-196	-25	-18	-15	175	473	466	370	336	276	144	-5	-78	-55	253	142	50	49

Study ID :5-APR-91 13:20:33
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9222	9357	9496	9618	9731	9856	9995	10127	10253	10372	10488	10609	10738	10891	11067	11253	11438	11624	11806	11990
Observed Rate	1.46%	1.49%	1.28%	1.18%	1.28%	1.41%	1.32%	1.25%	1.16%	1.12%	1.16%	1.22%	1.42%	1.61%	1.68%	1.64%	1.63%	1.56%	1.56%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	19	34	50	66	82	99	117	136	155	174	193	206	210	214	215
New Commercial 1	0	1	4	8	17	31	44	58	73	88	103	119	135	151	168	184	201	218	236	254
Commercial R&R 1	0	5	10	14	19	24	29	34	38	43	48	53	57	62	67	72	77	81	86	91
New SF Res 1	0	0	1	2	4	7	9	12	15	17	20	23	26	29	32	35	37	40	43	46
New MF Res 1	0	0	0	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	4	7	12	16	21	26	31	36	41	45	50	55	60	65	70	74	79
New Res Light 1	0	0	1	1	2	3	4	6	7	8	9	10	12	13	14	15	16	18	19	20
Wtr Htr Heat Pumps	0	0	1	2	4	6	8	10	13	15	18	21	23	26	29	31	34	36	39	42
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	152	155
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	104	107
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Subtotal	0	22	72	138	223	328	431	537	646	752	852	947	1040	1132	1226	1320	1408	1485	1561	1631
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	72	80	87	87	87	87
Thermal Eff Imp	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	80	240	240	380	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	0	8	41	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	8	8	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	0	88	128	192	296	296	296	400	544	632	712	960
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	17
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	155	350	733	906	1094	1160	1240	1356	1720	1720	1839	1990	2086	2172	2515
Total Firm Resources	9519	9553	9599	9432	9454	9622	9756	10080	10241	10418	10533	10658	10842	11242	11292	11345	11530	11715	11896	12072
Load/Resource Balance	297	196	102	-186	-277	-234	-239	-47	-13	46	45	48	103	351	225	92	92	91	90	82

Study ID :5-APR-91 13:20:33
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4611	4678	4751	4815	4877	4945	5018	5088	5155	5218	5277	5340	5406	5485	5575	5670	5764	5859	5951	6045
Observed Rate	1.46%	1.55%	1.35%	1.29%	1.39%	1.48%	1.39%	1.31%	1.22%	1.14%	1.18%	1.24%	1.45%	1.64%	1.71%	1.66%	1.64%	1.58%	1.58%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2166	2246	2301	2347	2426	2510	2584	2522	2606	2687	2740	2795	2874	2964	3043	3015	3045	3135	3223	3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	13	18	24	30	37	44	52	59	66	73	77	79	80	81
New Commercial 1	0	0	1	2	5	9	12	16	20	24	27	31	36	40	44	49	53	57	62	67
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	1	2	4	5	6	8	9	10	12	13	15	16	17	19	20	22	23
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	7	9	11	12	14	16	17	19	21	23	24	26	27
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	13	14	15	16
Subtotal	0	0	3	5	13	25	39	51	66	80	93	110	127	142	157	173	188	197	208	217
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4611	4679	4754	4821	4890	4970	5056	5007	5083	5156	5228	5303	5381	5471	5573	5685	5791	5891	5989	6095
Load/Resource Balance	0	1	3	6	13	25	38	-81	-72	-62	-49	-36	-25	-14	-2	15	26	32	38	50

Study ID :5-APR-91 13:20:33
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16861	17098	17329	17550	17768	18008	18274	18529	18773	19005	19229	19463	19710	19999	20332	20682	21031	21382	21726	22076
Observed Rate	1.41%	1.35%	1.27%	1.25%	1.35%	1.48%	1.39%	1.32%	1.23%	1.18%	1.22%	1.27%	1.47%	1.66%	1.72%	1.69%	1.67%	1.61%	1.61%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	11	34	61	88	116	145	176	209	244	278	311	345	367	375	381	384
New Commercial 1	0	1	6	11	25	45	63	84	105	126	146	169	192	215	239	262	286	309	335	361
Commercial R&R 1	0	7	15	21	29	36	44	51	57	65	72	80	86	94	101	108	116	122	130	137
New SF Res 1	0	0	3	4	9	15	19	25	31	36	41	48	53	60	65	71	76	82	88	94
New MF Res 1	0	0	0	1	1	3	4	5	6	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	8	13	20	28	36	45	54	61	70	78	86	95	104	112	120	128	136
New Res Light 1	0	0	1	2	4	5	7	10	12	14	15	17	20	22	24	26	27	30	32	34
Wtr Htr Heat Pumps	0	0	1	2	6	8	12	16	21	26	31	36	40	45	50	54	61	65	70	75
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	304	310
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	208	214
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Subtotal	0	37	124	235	383	556	833	1109	1388	1572	1739	1902	2062	2219	2377	2538	2687	2815	2943	3056
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	50	65	80	80	95	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	81	86	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	11	22	33	47	55	62	72	79	83	94	101	101	101	101
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	50	50	50	50	50	50	50	50	50	56	56	56	56	56	56
Cogen 1	0	0	0	0	0	80	240	240	380	420	420	420	420	420	420	420	420	420	440	440
Cogen 2	0	0	0	0	0	0	0	0	8	41	49	49	49	49	49	49	49	49	49	49
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	8	8	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	0	88	128	192	296	296	296	400	544	632	712	960
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	17
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	155	350	733	921	1128	1209	1289	1423	1807	1822	1948	2456	2552	2658	3001
Total Firm Resources	19301	19326	19362	19437	19549	19817	20250	20875	21157	21361	21562	21753	21934	22333	22478	22735	23404	23649	23906	24259
Load/Resource Balance	256	74	-91	-205	-282	-223	-26	345	382	354	331	288	222	332	145	52	372	265	178	181

Study ID :5-APR-91 13:21:20
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2983	2993	2988	3004	3036	3072	3111	3147	3182	3216	3249	3284	3320	3362	3412	3464	3514	3565	3616	3670
Observed Rate	0.32%	-0.18%	0.55%	1.08%	1.18%	1.27%	1.16%	1.10%	1.07%	1.02%	1.08%	1.10%	1.26%	1.49%	1.51%	1.45%	1.43%	1.45%	1.49%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2191	-2243	-2303	-2128	-2178	-2233	-2278	-2202	-2258	-2313	-2343	-2376	-2429	-2492	-2545	-2488	-2489	-2550	-2612	-2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	13	19	25	31	38	46	54	61	68	75	79	81	82	83
New Commercial 1	0	0	0	1	2	4	6	7	9	11	13	15	16	18	20	22	24	27	29	31
Commercial R&R 1	0	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30	32	34	36	38
New SF Res 1	0	0	1	1	2	3	4	5	6	7	8	9	11	12	13	14	15	16	18	19
New MF Res 1	0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	1	2	4	5	7	9	10	12	14	16	17	19	21	22	24	26	27
New Res Light 1	0	0	0	1	1	2	2	3	4	5	5	6	7	7	8	9	10	10	11	12
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	3	4	4	5	6	7	8	9	10	11	12	13	14
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	35	35	35	35	35	35	35	35	35	35
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	70	70	70	70	70	70	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	44	44	44	44	44	44	44	44	44	44
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	48	48	48	48	48	48	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	68	68	68	68	68	68	68	68	68	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12	12	12	12	12	12	12	12	12	12	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61	61	61	61	61	61	61	61	61	61	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	47	90	139	197	258	315	373	431	544	659	773	787	803	820	832	843	854	863
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5252	5234	5194	5401	5448	5496	5638	5904	5861	5821	5899	5974	5965	5847	5818	5897	5915	5869	5823	5895
Load/Resource Balance	163	269	367	693	840	986	1090	1320	1243	1169	1214	1254	1209	1051	972	1000	967	871	774	792

Study ID :5-APR-91 13:21:20
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9075	9108	9161	9219	9283	9356	9441	9513	9582	9648	9713	9786	9863	9962	10084	10210	10333	10459	10583	10715
Observed Rate	0.37%	0.58%	0.64%	0.70%	0.78%	0.91%	0.77%	0.72%	0.69%	0.68%	0.75%	0.78%	1.00%	1.22%	1.25%	1.21%	1.22%	1.19%	1.24%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	18	32	47	62	78	94	112	130	148	166	183	194	198	201	203
New Commercial 1	0	1	2	6	13	24	34	45	56	68	79	91	104	116	129	142	155	168	182	197
Commercial R&R 1	0	4	8	12	16	20	23	27	31	35	39	43	47	51	55	59	63	66	70	74
New SF Res 1	0	0	1	2	3	5	7	9	11	13	15	17	19	22	24	26	28	30	32	35
New MF Res 1	0	0	0	1	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	3	6	10	14	18	23	28	32	37	42	46	51	55	60	64	68	73
New Res Light 1	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Wtr Htr Heat Pumps	0	0	1	2	3	4	6	8	10	12	14	16	19	21	23	25	27	29	31	34
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	143	147	148
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	92	95	95	95
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	14	14	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	21	67	133	213	309	407	505	606	709	799	886	976	1060	1147	1233	1312	1377	1436	1495
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	5	19	33	33	33	43	52	62	71	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	7	11	11	11	22	29	40	47	54	62	69
Thermal Eff Imp	0	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	40	80	140	260	360	400	420	420
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	5	15	30	104	475	482	486	496	545	606	682	859	974	1021	1049	1413
Total Firm Resources	9519	9551	9595	9420	9432	9463	9411	9420	9773	9761	9807	9854	9965	10055	10175	10277	10418	10543	10650	10831
Load/Resource Balance	444	443	434	201	149	108	-30	-93	191	114	94	68	102	94	91	68	85	84	67	116

Study ID :5-APR-91 13:21:20
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4529	4537	4565	4596	4630	4668	4712	4751	4788	4824	4860	4899	4938	4989	5051	5115	5179	5243	5308	5376
Observed Rate	0.18%	0.61%	0.67%	0.74%	0.82%	0.95%	0.82%	0.79%	0.75%	0.74%	0.80%	0.80%	1.02%	1.25%	1.27%	1.24%	1.25%	1.23%	1.28%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2084	2105	2115	2128	2178	2233	2278	2202	2258	2313	2343	2376	2429	2492	2545	2488	2489	2550	2612	2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	12	17	23	29	35	42	49	56	63	69	73	75	76	76
New Commercial 1	0	0	1	2	4	7	9	12	15	18	21	24	27	31	34	37	41	44	48	52
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	1	2	3	3	5	6	7	8	9	10	11	12	13	14	15	16	17
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	1	2	3	5	6	8	10	11	13	14	16	18	19	21	22	24	25
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	2	3	4	5	6	7	8	8	9	10	11	12	13
Subtotal	0	0	2	4	10	21	32	43	56	69	81	96	109	124	137	149	162	170	179	186
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4529	4538	4567	4600	4640	4689	4744	4679	4725	4771	4818	4869	4920	4981	5054	5135	5209	5279	5349	5428
Load/Resource Balance	0	1	2	4	11	21	32	-72	-63	-53	-42	-29	-18	-8	3	20	31	36	41	52

Study ID :5-APR-91 13:21:20
Study Title:DIVERSE SUPPLY SCENARIO - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16587	16638	16713	16819	16949	17096	17264	17412	17552	17688	17822	17969	18121	18312	18547	18789	19026	19267	19508	19760
Observed Rate	0.31%	0.45%	0.63%	0.78%	0.87%	0.98%	0.85%	0.81%	0.77%	0.76%	0.83%	0.85%	1.05%	1.28%	1.31%	1.26%	1.27%	1.25%	1.30%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	10	32	57	83	110	138	167	200	233	265	297	327	346	354	359	362
New Commercial 1	0	1	3	9	19	35	49	64	80	97	113	130	147	165	183	201	220	239	259	280
Commercial R&R 1	0	6	12	18	24	30	35	41	47	53	59	65	71	77	83	89	95	100	106	112
New SF Res 1	0	0	2	4	7	11	14	19	23	27	31	35	40	45	49	53	57	61	66	71
New MF Res 1	0	0	0	1	1	1	4	5	5	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	5	10	17	24	31	40	48	55	64	72	79	88	95	103	110	118	125
New Res Light 1	0	0	0	2	3	5	6	8	10	12	13	15	17	18	20	22	24	25	27	29
Wtr Htr Heat Pumps	0	0	1	2	3	6	10	13	17	20	24	28	33	37	40	44	48	52	56	61
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	91	94	94	94	94	94	94	94	94	94
Industrial 1	0	4	12	30	48	66	86	104	122	140	149	158	168	177	186	196	205	213	217	218
Irrigation 1	0	0	2	4	5	7	9	11	12	14	15	16	17	18	19	20	21	22	23	24
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	90	95	100	104	109	114	119	124	128	133
Industrial 2	0	2	8	20	32	46	58	70	82	96	102	108	115	121	128	134	140	143	143	143
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	221	240	259	278	297	317	336	355	374	393
MF Res Weath	0	3	8	14	22	28	35	41	48	55	56	56	56	56	56	56	56	56	56	56
SF Res Weath	0	5	17	31	46	60	75	89	104	118	120	120	120	120	120	120	120	120	120	120
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	14	14	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	36	116	227	362	527	697	863	1035	1209	1424	1641	1858	1971	2087	2202	2306	2390	2469	2544
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	5	19	33	33	33	43	52	62	71	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	7	11	11	11	22	29	40	47	54	62	69
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	40	80	140	260	360	400	420	420
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	49	49	49	49
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	5	15	30	104	475	482	486	496	545	606	682	859	974	1021	1049	1413
Total Firm Resources	19301	19323	19355	19421	19520	19648	19793	20003	20359	20353	20524	20697	20849	20883	21046	21309	21542	21691	21822	22154
Load/Resource Balance	607	713	803	898	1000	1115	1092	1155	1371	1229	1266	1293	1293	1136	1066	1087	1083	991	881	961

Study ID :5-APR-91 13:28:16
Study Title:DIVERSE SUPPLY SCENARIO - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2934	2915	2888	2881	2892	2907	2923	2936	2948	2958	2969	2982	2995	3012	3035	3058	3081	3103	3128	3155
Observed Rate	-0.63%	-0.95%	-0.24%	0.37%	0.51%	0.55%	0.47%	0.41%	0.34%	0.36%	0.45%	0.44%	0.57%	0.74%	0.76%	0.75%	0.71%	0.80%	0.87%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2108	-2104	-2122	-1903	-1918	-1937	-1946	-1854	-1876	-1895	-1889	-1889	-1909	-1936	-1949	-1851	-1809	-1826	-1846	-1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	11	16	22	27	33	40	47	53	58	64	67	68	69	69
New Commercial 1	0	0	0	1	1	3	4	5	6	8	9	11	12	13	15	16	18	20	21	23
Commercial R&R 1	0	1	3	4	6	7	9	10	11	13	14	16	17	19	20	22	23	24	26	27
New SF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	8	8	9
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3	3
New Manuf Housing 1	0	0	0	1	2	2	3	4	6	7	8	9	10	11	12	13	14	15	17	18
New Res Light 1	0	0	0	0	1	1	1	2	2	2	3	3	3	4	4	5	5	5	6	6
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	1	2	2	3	3	4	4	5	5	6	6	7	7
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	35	35	35	35	35	35	35	35	35	35
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	70	70	70	70	70	70	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	44	44	44	44	44	44	44	44	44	44
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	48	48	48	48	48	48	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	68	68	68	68	68	68	68	68	68	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12	12	12	12	12	12	12	12	12	12	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61	61	61	61	61	61	61	61	61	61	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	14	44	86	135	188	245	297	352	407	419	431	444	455	466	477	486	492	501	506
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5336	5372	5373	5623	5702	5782	5958	6235	6223	6214	6226	6234	6156	6070	6076	6192	6249	6244	6236	6346
Load/Resource Balance	420	676	906	1364	1635	1901	2062	2326	2303	2407	2531	2649	2681	2578	2562	2655	2688	2662	2629	2712

Study ID :5-APR-91 13:28:16
Study Title:DIVERSE SUPPLY SCENARIO - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	8920	8853	8823	8795	8785	8785	8795	8797	8791	8779	8771	8772	8776	8796	8831	8867	8901	8934	8973	9019
Observed Rate	-0.75%	-0.35%	-0.32%	-0.11%	0.01%	0.11%	0.02%	-0.07%	-0.14%	-0.09%	0.02%	0.05%	0.23%	0.39%	0.41%	0.38%	0.37%	0.44%	0.51%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	5	16	28	41	54	67	82	97	113	128	142	157	165	168	169	169
New Commercial 1	0	0	1	3	8	16	23	32	40	48	57	66	76	85	95	105	114	125	135	146
Commercial R&R 1	0	3	6	9	11	14	17	20	23	26	28	31	34	37	40	43	45	48	51	54
New SF Res 1	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New MF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8
New Manuf Housing 1	0	0	1	2	4	6	9	12	15	17	20	23	26	29	32	35	38	41	44	47
New Res Light 1	0	0	0	0	1	1	2	2	3	3	4	4	5	6	6	7	7	8	8	9
Wtr Htr Heat Pumps	0	0	0	1	1	2	3	4	5	6	7	8	10	11	12	13	14	15	17	18
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	50	50	50	53	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	72	76	84	93	103	112	118
Irrigation 1	0	0	1	2	3	4	5	6	7	8	8	8	8	8	9	10	11	12	13	14
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	41	41	41	44	48	53	58	63	68	72
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	49	52	57	64	70	77	81
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	134	134	134	134	134	137	144	156	172	192
MF Res Weath	0	2	6	11	17	22	27	32	38	43	43	43	43	43	43	43	43	43	43	43
SF Res Weath	0	2	8	15	22	29	36	43	50	57	57	57	57	57	57	57	57	57	57	57
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	13	13	13	13	13	13	13	13
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	18	61	122	195	282	372	460	552	640	673	705	742	784	835	891	945	1002	1061	1116
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	19	29
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	29	44	64
Total Firm Resources	9519	9549	9590	9410	9410	9423	9346	9271	9241	9212	9193	9176	9185	9170	9179	9079	9093	9173	9267	9103
Load/Resource Balance	599	696	767	615	626	638	551	474	450	433	423	404	409	374	348	212	192	239	293	83

Study ID :5-APR-91 13:28:16
Study Title:DIVERSE SUPPLY SCENARIO - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4445	4398	4384	4371	4369	4372	4380	4384	4386	4384	4383	4386	4391	4403	4424	4445	4463	4481	4502	4526
Observed Rate	-1.05%	-0.33%	-0.30%	-0.05%	0.07%	0.19%	0.09%	0.04%	-0.04%	-0.04%	0.07%	0.11%	0.29%	0.46%	0.47%	0.41%	0.40%	0.47%	0.55%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2001	1966	1934	1903	1918	1937	1946	1854	1876	1895	1889	1889	1909	1936	1949	1851	1809	1826	1846	1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	10	15	20	25	30	37	43	48	54	59	62	63	64	64
New Commercial 1	0	0	0	1	2	4	6	9	11	13	15	18	20	22	25	27	30	33	35	38
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	0	1	1	2	2	3	3	3	4	4	5	5	6	6	7	7	8
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3
New Manuf Housing 1	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	1	2	2	3	3	3	4	4	5	5	6	6	7
Subtotal	0	0	0	2	6	14	22	32	42	50	59	71	80	91	101	111	118	125	129	136
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4445	4399	4385	4373	4376	4387	4403	4318	4328	4334	4343	4357	4371	4393	4422	4459	4487	4510	4535	4570
Load/Resource Balance	0	0	1	2	7	15	23	-66	-58	-50	-40	-29	-19	-11	-1	14	24	29	33	44

Study ID :5-APR-91 13:28:16
Study Title:DIVERSE SUPPLY SCENARIO - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16299	16167	16094	16047	16045	16064	16098	16118	16125	16121	16122	16140	16162	16212	16290	16370	16445	16518	16603	16701
Observed Rate	-0.81%	-0.45%	-0.30%	-0.01%	0.12%	0.21%	0.12%	0.05%	-0.03%	0.01%	0.11%	0.14%	0.31%	0.48%	0.49%	0.46%	0.44%	0.51%	0.59%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	9	29	49	72	96	119	145	174	203	229	254	280	294	299	302	302
New Commercial 1	0	0	1	5	11	23	33	46	57	69	81	95	108	120	135	148	162	178	191	207
Commercial R&R 1	0	4	9	13	17	21	26	30	34	39	42	47	51	56	60	65	68	72	77	81
New SF Res 1	0	0	0	1	3	4	7	8	11	12	14	16	18	20	22	24	26	29	30	33
New MF Res 1	0	0	0	0	1	1	3	4	5	5	6	6	8	9	10	10	11	11	13	14
New Manuf Housing 1	0	0	1	4	7	10	15	20	26	30	35	40	45	50	55	60	65	70	76	81
New Res Light 1	0	0	0	0	2	2	3	4	5	5	7	7	8	10	10	12	12	13	14	15
Wtr Htr Heat Pumps	0	0	0	1	1	4	5	6	9	10	13	14	17	19	21	23	25	27	30	32
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	85	85	85	88	94	94	94	94	94	94
Industrial 1	0	4	12	30	48	66	86	104	122	140	140	140	140	142	146	154	163	173	182	188
Irrigation 1	0	0	2	4	5	7	9	11	12	14	14	14	14	14	15	16	17	18	19	20
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	85	85	85	88	92	97	102	107	112	116
Industrial 2	0	2	8	20	32	46	58	70	82	96	96	96	96	97	100	105	112	118	125	129
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	202	202	202	202	202	205	212	224	240	260
MF Res Weath	0	3	8	14	22	28	35	41	48	55	55	55	55	55	55	55	55	55	55	55
SF Res Weath	0	5	17	31	46	60	75	89	104	118	118	118	118	118	118	118	118	118	118	118
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	13	13	13	13	13	13	13	13
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	32	105	210	336	484	639	789	946	1097	1151	1207	1266	1330	1402	1479	1549	1619	1691	1758
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	19	29
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	29	44	64
Total Firm Resources	19300	19320	19347	19406	19488	19592	19707	19825	19792	19760	19762	19767	19712	19633	19678	19730	19828	19926	20038	20019
Load/Resource Balance	1019	1372	1674	1982	2267	2554	2636	2735	2696	2791	2914	3024	3071	2941	2909	2881	2904	2930	2956	2839

Study ID :8-APR-91 12:31:47
Study Title:No Coal or Nuclear - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2934	2915	2888	2881	2892	2907	2923	2936	2948	2958	2969	2982	2995	3012	3035	3058	3081	3103	3128	3155
Observed Rate	-0.63%	-0.95%	-0.24%	0.37%	0.51%	0.55%	0.47%	0.41%	0.34%	0.36%	0.45%	0.44%	0.57%	0.74%	0.76%	0.75%	0.71%	0.80%	0.87%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2108	-2104	-2122	-1903	-1918	-1937	-1946	-1854	-1876	-1895	-1889	-1889	-1909	-1936	-1949	-1851	-1809	-1826	-1846	-1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	11	16	22	27	33	40	47	53	58	64	67	68	69	69
New Commercial 1	0	0	0	1	1	3	4	5	6	8	9	11	12	13	15	16	18	20	21	23
Commercial R&R 1	0	1	3	4	6	7	9	10	11	13	14	16	17	19	20	22	23	24	26	27
New SF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	8	8	9
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3	3
New Manuf Housing 1	0	0	0	1	2	2	3	4	6	7	8	9	10	11	12	13	14	15	17	18
New Res Light 1	0	0	0	0	1	1	1	2	2	2	3	3	3	4	4	5	5	5	6	6
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	1	2	2	3	3	4	4	5	5	6	6	7	7
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	35	35	35	35	35	35	35	35	35	35
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	70	70	70	70	70	70	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	44	44	44	44	44	44	44	44	44	44
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	48	48	48	48	48	48	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	68	68	68	68	68	68	68	68	68	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12	12	12	12	12	12	12	12	12	12	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61	61	61	61	61	61	61	61	61	61	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	14	44	86	135	188	245	297	352	407	419	431	444	455	466	477	486	492	501	506
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5336	5372	5373	5623	5702	5782	5958	6235	6223	6214	6226	6234	6156	6070	6076	6192	6249	6244	6236	6346
Load/Resource Balance	420	676	906	1364	1635	1901	2062	2326	2303	2407	2531	2649	2681	2578	2562	2655	2688	2662	2629	2712

Study ID :8-APR-91 12:31:47
Study Title:No Coal or Nuclear - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	8920	8853	8823	8795	8785	8785	8795	8797	8791	8779	8771	8772	8776	8796	8831	8867	8901	8934	8973	9019
Observed Rate	-0.75%	-0.35%	-0.32%	-0.11%	0.01%	0.11%	0.02%	-0.07%	-0.14%	-0.09%	0.02%	0.05%	0.23%	0.39%	0.41%	0.38%	0.37%	0.44%	0.51%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	5	16	28	41	54	67	82	97	113	128	142	157	165	168	169	169
New Commercial 1	0	0	1	3	8	16	23	32	40	48	57	66	76	85	95	105	114	125	135	146
Commercial R&R 1	0	3	6	9	11	14	17	20	23	26	28	31	34	37	40	43	45	48	51	54
New SF Res 1	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New MF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8
New Manuf Housing 1	0	0	1	2	4	6	9	12	15	17	20	23	26	29	32	35	38	41	44	47
New Res Light 1	0	0	0	0	1	1	2	2	3	3	4	4	5	6	6	7	7	8	8	9
Wtr Htr Heat Pumps	0	0	0	1	1	2	3	4	5	6	7	8	10	11	12	13	14	15	17	18
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	50	50	50	53	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	72	76	84	93	103	112	118
Irrigation 1	0	0	1	2	3	4	5	6	7	8	8	8	8	8	9	10	11	12	13	14
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	41	41	41	44	48	53	58	63	68	72
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	49	52	57	64	70	77	81
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	134	134	134	134	134	137	144	156	172	192
MF Res Weath	0	2	6	11	17	22	27	32	38	43	43	43	43	43	43	43	43	43	43	43
SF Res Weath	0	2	8	15	22	29	36	43	50	57	57	57	57	57	57	57	57	57	57	57
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	13	13	13	13	13	13	13	13
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	18	61	122	195	282	372	460	552	640	673	705	742	784	835	891	945	1002	1061	1116
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	19	29
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	29	44	64
Total Firm Resources	9519	9549	9590	9410	9410	9423	9346	9271	9241	9212	9193	9176	9185	9170	9179	9079	9093	9173	9267	9103
Load/Resource Balance	599	696	767	615	626	638	551	474	450	433	423	404	409	374	348	212	192	239	293	83

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Study Title:No Coal or Nuclear - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4445	4398	4384	4371	4369	4372	4380	4384	4386	4384	4383	4386	4391	4403	4424	4445	4463	4481	4502	4526
Observed Rate	-1.05%	-0.33%	-0.30%	-0.05%	0.07%	0.19%	0.09%	0.04%	-0.04%	-0.04%	0.07%	0.11%	0.29%	0.46%	0.47%	0.41%	0.40%	0.47%	0.55%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2001	1966	1934	1903	1918	1937	1946	1854	1876	1895	1889	1889	1909	1936	1949	1851	1809	1826	1846	1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	10	15	20	25	30	37	43	48	54	59	62	63	64	64
New Commercial 1	0	0	0	1	2	4	6	9	11	13	15	18	20	22	25	27	30	33	35	38
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	0	1	1	2	2	3	3	3	4	4	5	5	6	6	7	7	8
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3
New Manuf Housing 1	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	1	2	2	3	3	3	4	4	5	5	6	6	7
Subtotal	0	0	0	2	6	14	22	32	42	50	59	71	80	91	101	111	118	125	129	136
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4445	4399	4385	4373	4376	4387	4403	4318	4328	4334	4343	4357	4371	4393	4422	4459	4487	4510	4535	4570
Load/Resource Balance	0	0	1	2	7	15	23	-66	-58	-50	-40	-29	-19	-11	-1	14	24	29	33	44

Study ID :8-APR-91 12:31:47
Study Title:No Coal or Nuclear - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16299	16167	16094	16047	16045	16064	16098	16118	16125	16121	16122	16140	16162	16212	16290	16370	16445	16518	16603	16701
Observed Rate	-0.81%	-0.45%	-0.30%	-0.01%	0.12%	0.21%	0.12%	0.05%	-0.03%	0.01%	0.11%	0.14%	0.31%	0.48%	0.49%	0.46%	0.44%	0.51%	0.59%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	9	29	49	72	96	119	145	174	203	229	254	280	294	299	302	302
New Commercial 1	0	0	1	5	11	23	33	46	57	69	81	95	108	120	135	148	162	178	191	207
Commercial R&R 1	0	4	9	13	17	21	26	30	34	39	42	47	51	56	60	65	68	72	77	81
New SF Res 1	0	0	0	1	3	4	7	8	11	12	14	16	18	20	22	24	26	29	30	33
New MF Res 1	0	0	0	0	1	1	3	4	5	5	6	6	8	9	10	10	11	11	13	14
New Manuf Housing 1	0	0	1	4	7	10	15	20	26	30	35	40	45	50	55	60	65	70	76	81
New Res Light 1	0	0	0	0	2	2	3	4	5	5	7	7	8	10	10	12	12	13	14	15
Wtr Htr Heat Pumps	0	0	0	1	1	4	5	6	9	10	13	14	17	19	21	23	25	27	30	32
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	85	85	85	88	94	94	94	94	94	94
Industrial 1	0	4	12	30	48	66	86	104	122	140	140	140	140	142	146	154	163	173	182	188
Irrigation 1	0	0	2	4	5	7	9	11	12	14	14	14	14	14	15	16	17	18	19	20
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	85	85	85	88	92	97	102	107	112	116
Industrial 2	0	2	8	20	32	46	58	70	82	96	96	96	96	97	100	105	112	118	125	129
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	202	202	202	202	202	205	212	224	240	260
MF Res Weath	0	3	8	14	22	28	35	41	48	55	55	55	55	55	55	55	55	55	55	55
SF Res Weath	0	5	17	31	46	60	75	89	104	118	118	118	118	118	118	118	118	118	118	118
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	13	13	13	13	13	13	13	13
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	32	105	210	336	484	639	789	946	1097	1151	1207	1266	1330	1402	1479	1549	1619	1691	1758
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	19	29
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	29	44	64
Total Firm Resources	19300	19320	19347	19406	19488	19592	19707	19825	19792	19760	19762	19767	19712	19633	19678	19730	19828	19926	20038	20019
Load/Resource Balance	1019	1372	1674	1982	2267	2554	2636	2735	2696	2791	2914	3024	3071	2941	2909	2881	2904	2930	2956	2839

Study Title:No Coal or Nuclear - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2983	2993	2988	3004	3036	3072	3111	3147	3182	3216	3249	3284	3320	3362	3412	3464	3514	3565	3616	3670
Observed Rate	0.32%	-0.18%	0.55%	1.08%	1.18%	1.27%	1.16%	1.10%	1.07%	1.02%	1.08%	1.10%	1.26%	1.49%	1.51%	1.45%	1.43%	1.45%	1.49%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2191	-2243	-2303	-2128	-2178	-2233	-2278	-2202	-2258	-2313	-2343	-2376	-2429	-2492	-2545	-2488	-2489	-2550	-2612	-2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	13	19	25	31	38	46	54	61	68	75	79	81	82	83
New Commercial 1	0	0	0	1	2	4	6	7	9	11	13	15	16	18	20	22	24	27	29	31
Commercial R&R 1	0	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30	32	34	36	38
New SF Res 1	0	0	1	1	2	3	4	5	6	7	8	9	11	12	13	14	15	16	18	19
New MF Res 1	0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	1	2	4	5	7	9	10	12	14	16	17	19	21	22	24	26	27
New Res Light 1	0	0	0	1	1	2	2	3	4	5	5	6	7	7	8	9	10	10	11	12
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	3	4	4	5	6	7	8	9	10	11	12	13	14
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	35	35	35	35	35	35	35	35	35	35
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	70	70	70	70	70	70	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	44	44	44	44	44	44	44	44	44	44
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	48	48	48	48	48	48	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	68	68	68	68	68	68	68	68	68	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12	12	12	12	12	12	12	12	12	12	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61	61	61	61	61	61	61	61	61	61	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	47	90	139	197	258	315	373	431	544	659	773	787	803	820	832	843	854	863
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5252	5234	5194	5401	5448	5496	5638	5904	5861	5821	5899	5974	5965	5847	5818	5897	5915	5869	5823	5895
Load/Resource Balance	163	269	367	693	840	986	1090	1320	1243	1169	1214	1254	1209	1051	972	1000	967	871	774	792

Study ID :8-APR-91 16:05:22
Study Title:No Coal or Nuclear - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9075	9108	9161	9219	9283	9356	9441	9513	9582	9648	9713	9786	9863	9962	10084	10210	10333	10459	10583	10715
Observed Rate	0.37%	0.58%	0.64%	0.70%	0.78%	0.91%	0.77%	0.72%	0.69%	0.68%	0.75%	0.78%	1.00%	1.22%	1.25%	1.21%	1.22%	1.19%	1.24%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	18	32	47	62	78	94	112	130	148	166	183	194	198	201	203
New Commercial 1	0	1	2	6	13	24	34	45	56	68	79	91	104	116	129	142	155	168	182	197
Commercial R&R 1	0	4	8	12	16	20	23	27	31	35	39	43	47	51	55	59	63	66	70	74
New SF Res 1	0	0	1	2	3	5	7	9	11	13	15	17	19	22	24	26	28	30	32	35
New MF Res 1	0	0	0	1	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	3	6	10	14	18	23	28	32	37	42	46	51	55	60	64	68	73
New Res Light 1	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Wtr Htr Heat Pumps	0	0	1	2	3	4	6	8	10	12	14	16	19	21	23	25	27	29	31	34
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	143	147	148
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	92	95	95	95
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	14	14	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	21	67	133	213	309	407	505	606	709	799	886	976	1060	1147	1233	1312	1377	1436	1495
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	5	19	33	33	33	43	52	62	71	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	7	11	11	11	22	29	40	47	54	62	69
Thermal Eff Imp	0	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	40	80	140	260	360	400	420	420
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	5	15	30	104	475	482	486	496	545	606	682	859	974	1021	1049	1413
Total Firm Resources	9519	9551	9595	9420	9432	9463	9411	9420	9773	9761	9807	9854	9965	10055	10175	10277	10418	10543	10650	10831
Load/Resource Balance	444	443	434	201	149	108	-30	-93	191	114	94	68	102	94	91	68	85	84	67	116

Study ID :8-APR-91 16:05:22
Study Title:No Coal or Nuclear - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4529	4537	4565	4596	4630	4668	4712	4751	4788	4824	4860	4899	4938	4989	5051	5115	5179	5243	5308	5376
Observed Rate	0.18%	0.61%	0.67%	0.74%	0.82%	0.95%	0.82%	0.79%	0.75%	0.74%	0.80%	0.80%	1.02%	1.25%	1.27%	1.24%	1.25%	1.23%	1.28%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2084	2105	2115	2128	2178	2233	2278	2202	2258	2313	2343	2376	2429	2492	2545	2488	2489	2550	2612	2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	12	17	23	29	35	42	49	56	63	69	73	75	76	76
New Commercial 1	0	0	1	2	4	7	9	12	15	18	21	24	27	31	34	37	41	44	48	52
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	1	2	3	3	5	6	7	8	9	10	11	12	13	14	15	16	17
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	1	2	3	5	6	8	10	11	13	14	16	18	19	21	22	24	25
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	2	3	4	5	6	7	8	8	9	10	11	12	13
Subtotal	0	0	2	4	10	21	32	43	56	69	81	96	109	124	137	149	162	170	179	186
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4529	4538	4567	4600	4640	4689	4744	4679	4725	4771	4818	4869	4920	4981	5054	5135	5209	5279	5349	5428
Load/Resource Balance	0	1	2	4	11	21	32	-72	-63	-53	-42	-29	-18	-8	3	20	31	36	41	52

Study ID :8-APR-91 16:05:22
Study Title:No Coal or Nuclear - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16587	16638	16713	16819	16949	17096	17264	17412	17552	17688	17822	17969	18121	18312	18547	18789	19026	19267	19508	19760
Observed Rate	0.31%	0.45%	0.63%	0.78%	0.87%	0.98%	0.85%	0.81%	0.77%	0.76%	0.83%	0.85%	1.05%	1.28%	1.31%	1.26%	1.27%	1.25%	1.30%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	10	32	57	83	110	138	167	200	233	265	297	327	346	354	359	362
New Commercial 1	0	1	3	9	19	35	49	64	80	97	113	130	147	165	183	201	220	239	259	280
Commercial R&R 1	0	6	12	18	24	30	35	41	47	53	59	65	71	77	83	89	95	100	106	112
New SF Res 1	0	0	2	4	7	11	14	19	23	27	31	35	40	45	49	53	57	61	66	71
New MF Res 1	0	0	0	1	1	1	4	5	5	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	5	10	17	24	31	40	48	55	64	72	79	88	95	103	110	118	125
New Res Light 1	0	0	0	2	3	5	6	8	10	12	13	15	17	18	20	22	24	25	27	29
Wtr Htr Heat Pumps	0	0	1	2	3	6	10	13	17	20	24	28	33	37	40	44	48	52	56	61
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	91	94	94	94	94	94	94	94	94	94
Industrial 1	0	4	12	30	48	66	86	104	122	140	149	158	168	177	186	196	205	213	217	218
Irrigation 1	0	0	2	4	5	7	9	11	12	14	15	16	17	18	19	20	21	22	23	24
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	90	95	100	104	109	114	119	124	128	133
Industrial 2	0	2	8	20	32	46	58	70	82	96	102	108	115	121	128	134	140	143	143	143
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	221	240	259	278	297	317	336	355	374	393
MF Res Weath	0	3	8	14	22	28	35	41	48	55	56	56	56	56	56	56	56	56	56	56
SF Res Weath	0	5	17	31	46	60	75	89	104	118	120	120	120	120	120	120	120	120	120	120
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	14	14	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	36	116	227	362	527	697	863	1035	1209	1424	1641	1858	1971	2087	2202	2306	2390	2469	2544
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	5	19	33	33	33	43	52	62	71	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	7	11	11	11	22	29	40	47	54	62	69
Thermal Eff Imp	0	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	40	80	140	260	360	400	420	420
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	5	15	30	104	475	482	486	496	545	606	682	859	974	1021	1049	1413
Total Firm Resources	19301	19323	19355	19421	19520	19648	19793	20003	20359	20353	20524	20697	20849	20883	21046	21309	21542	21691	21822	22154
Load/Resource Balance	607	713	803	898	1000	1115	1092	1155	1371	1229	1266	1293	1293	1136	1066	1087	1083	991	881	961

Study ID :8-APR-91 12:31:01
Study Title:No Coal or Nuclear - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3028	3063	3082	3117	3160	3207	3261	3313	3365	3415	3464	3514	3566	3623	3689	3759	3829	3899	3969	4041
Observed Rate	1.16%	0.63%	1.12%	1.39%	1.51%	1.68%	1.60%	1.56%	1.48%	1.42%	1.46%	1.46%	1.62%	1.82%	1.88%	1.87%	1.83%	1.80%	1.80%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2273	-2384	-2489	-2347	-2426	-2510	-2584	-2522	-2606	-2687	-2740	-2795	-2874	-2964	-3043	-3015	-3045	-3135	-3223	-3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	8	14	20	26	33	40	48	56	64	71	79	84	86	87	88
New Commercial 1	0	0	1	1	3	5	7	10	12	14	16	19	21	24	27	29	32	34	37	40
Commercial R&R 1	0	2	5	7	10	12	15	17	19	22	24	27	29	32	34	36	39	41	44	46
New SF Res 1	0	0	1	1	3	4	5	7	8	10	11	13	14	16	17	19	20	22	23	25
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	8	10	12	13	15	17	19	21	23	24	26	28	30
New Res Light 1	0	0	0	1	2	2	3	4	5	6	6	7	8	9	10	11	11	12	13	14
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	6	7	8	9	10	11	12	14	15	16	17
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	152	155
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	104	107
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	49	92	147	203	363	521	676	740	794	845	895	945	994	1045	1091	1133	1174	1208
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	15	30	45	45	60	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	4	4	4	7	7	11	14	14	14	14	14
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	20
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	15	34	49	49	67	87	102	109	466	466	486	486
Total Firm Resources	5171	5094	5009	5185	5205	5225	5438	5788	5833	5787	5801	5792	5711	5621	5613	5705	6084	6043	6022	6092
Load/Resource Balance	-41	-123	-196	-25	-18	-15	175	473	466	370	336	276	144	-5	-78	-55	253	142	50	49

Study ID :8-APR-91 12:31:01
Study Title:No Coal or Nuclear - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9222	9357	9496	9618	9731	9856	9995	10127	10253	10372	10488	10609	10738	10891	11067	11253	11438	11624	11806	11990
Observed Rate	1.46%	1.49%	1.28%	1.18%	1.28%	1.41%	1.32%	1.25%	1.16%	1.12%	1.16%	1.22%	1.42%	1.61%	1.68%	1.64%	1.63%	1.56%	1.56%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	19	34	50	66	82	99	117	136	155	174	193	206	210	214	215
New Commercial 1	0	1	4	8	17	31	44	58	73	88	103	119	135	151	168	184	201	218	236	254
Commercial R&R 1	0	5	10	14	19	24	29	34	38	43	48	53	57	62	67	72	77	81	86	91
New SF Res 1	0	0	1	2	4	7	9	12	15	17	20	23	26	29	32	35	37	40	43	46
New MF Res 1	0	0	0	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	4	7	12	16	21	26	31	36	41	45	50	55	60	65	70	74	79
New Res Light 1	0	0	1	1	2	3	4	6	7	8	9	10	12	13	14	15	16	18	19	20
Wtr Htr Heat Pumps	0	0	1	2	4	6	8	10	13	15	18	21	23	26	29	31	34	36	39	42
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	152	155
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	104	107
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Subtotal	0	22	72	138	223	328	431	537	646	752	852	947	1040	1132	1226	1320	1408	1485	1561	1631
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	62	62	71	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	51	51	51	58	65	72	80	87	87
Thermal Eff Imp	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	80	240	240	380	400	400	400	400	400	400	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	0	8	41	41	41	41	41	41	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	8	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	0	112	112	112	112	112	200	416	560	640	712	944
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	17
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	155	350	733	906	1098	1473	1473	1473	1482	1589	1840	1991	2087	2172	2527
Total Firm Resources	9519	9553	9599	9432	9454	9622	9756	10080	10241	10422	10846	10890	10958	11004	11161	11346	11531	11715	11896	12084
Load/Resource Balance	297	196	102	-186	-277	-234	-239	-47	-13	50	357	280	219	112	94	94	94	92	90	94

Study ID :8-APR-91 12:31:01
Study Title:No Coal or Nuclear - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4611	4678	4751	4815	4877	4945	5018	5088	5155	5218	5277	5340	5406	5485	5575	5670	5764	5859	5951	6045
Observed Rate	1.46%	1.55%	1.35%	1.29%	1.39%	1.48%	1.39%	1.31%	1.22%	1.14%	1.18%	1.24%	1.45%	1.64%	1.71%	1.66%	1.64%	1.58%	1.58%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2166	2246	2301	2347	2426	2510	2584	2522	2606	2687	2740	2795	2874	2964	3043	3015	3045	3135	3223	3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	13	18	24	30	37	44	52	59	66	73	77	79	80	81
New Commercial 1	0	0	1	2	5	9	12	16	20	24	27	31	36	40	44	49	53	57	62	67
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	1	2	4	5	6	8	9	10	12	13	15	16	17	19	20	22	23
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	7	9	11	12	14	16	17	19	21	23	24	26	27
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	13	14	15	16
Subtotal	0	0	3	5	13	25	39	51	66	80	93	110	127	142	157	173	188	197	208	217
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4611	4679	4754	4821	4890	4970	5056	5007	5083	5156	5228	5303	5381	5471	5573	5685	5791	5891	5989	6095
Load/Resource Balance	0	1	3	6	13	25	38	-81	-72	-62	-49	-36	-25	-14	-2	15	26	32	38	50

Study ID :8-APR-91 12:31:01
Study Title:No Coal or Nuclear - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16861	17098	17329	17550	17768	18008	18274	18529	18773	19005	19229	19463	19710	19999	20332	20682	21031	21382	21726	22076
Observed Rate	1.41%	1.35%	1.27%	1.25%	1.35%	1.48%	1.39%	1.32%	1.23%	1.18%	1.22%	1.27%	1.47%	1.66%	1.72%	1.69%	1.67%	1.61%	1.61%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	11	34	61	88	116	145	176	209	244	278	311	345	367	375	381	384
New Commercial 1	0	1	6	11	25	45	63	84	105	126	146	169	192	215	239	262	286	309	335	361
Commercial R&R 1	0	7	15	21	29	36	44	51	57	65	72	80	86	94	101	108	116	122	130	137
New SF Res 1	0	0	3	4	9	15	19	25	31	36	41	48	53	60	65	71	76	82	88	94
New MF Res 1	0	0	0	1	1	3	4	5	6	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	8	13	20	28	36	45	54	61	70	78	86	95	104	112	120	128	136
New Res Light 1	0	0	1	2	4	5	7	10	12	14	15	17	20	22	24	26	27	30	32	34
Wtr Htr Heat Pumps	0	0	1	2	6	8	12	16	21	26	31	36	40	45	50	54	61	65	70	75
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	304	310
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	208	214
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Subtotal	0	37	124	235	383	556	833	1109	1388	1572	1739	1902	2062	2219	2377	2538	2687	2815	2943	3056
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	50	65	80	80	95	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	62	62	76	86	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	11	22	33	47	55	55	58	58	69	79	86	94	101	101
Thermal Eff Imp	0	0	0	0	0	50	50	50	50	50	50	50	50	50	56	56	56	56	56	56
Cogen 1	0	0	0	0	0	80	240	240	380	400	400	400	400	400	400	420	420	420	440	440
Cogen 2	0	0	0	0	0	0	0	0	8	41	41	41	41	41	41	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	8	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	0	112	112	112	112	112	200	416	560	640	712	944
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	17
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	105
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	155	350	733	921	1132	1522	1522	1540	1569	1691	1949	2457	2553	2658	3013
Total Firm Resources	19301	19326	19362	19437	19549	19817	20250	20875	21157	21365	21874	21985	22050	22095	22347	22736	23406	23649	23906	24271
Load/Resource Balance	256	74	-91	-205	-282	-223	-26	345	382	358	644	520	338	94	13	53	374	266	178	193

Study ID :5-APR-91 13:38:40
Study Title:No Coal or Nuclear - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3080	3141	3175	3229	3298	3370	3443	3514	3582	3647	3715	3787	3858	3935	4020	4107	4191	4276	4367	4456
Observed Rate	1.98%	1.09%	1.68%	2.14%	2.18%	2.18%	2.05%	1.93%	1.83%	1.85%	1.95%	1.87%	2.00%	2.15%	2.17%	2.04%	2.03%	2.12%	2.04%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2367	-2536	-2673	-2571	-2693	-2817	-2927	-2880	-2999	-3113	-3192	-3278	-3389	-3511	-3621	-3622	-3675	-3790	-3912	-3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	9	15	21	28	34	42	50	59	67	75	83	89	91	92	93
New Commercial 1	0	0	1	2	4	7	9	12	15	18	21	24	27	30	34	37	40	44	47	51
Commercial R&R 1	0	3	5	8	11	13	16	19	22	24	27	30	32	35	38	40	43	46	49	51
New SF Res 1	0	0	1	2	4	5	7	9	11	13	15	17	19	21	24	26	28	30	32	34
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	26	28	30	32
New Res Light 1	0	0	0	1	2	3	4	5	5	6	7	8	9	10	11	12	13	14	15	16
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	6	7	8	10	11	13	14	16	17	18	20	21
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	1	2	4	5	6	8	9	10	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	64	144	241	337	392	453	517	627	689	751	811	864	918	971	1026	1080	1131	1177	1225	1272
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	60	75	75	75	75	75	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357	714	714	714	714	714	714	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	0	0	7	11	11	14	18	18	18	18	18	18	18	18
Thermal Eff Imp	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	0	0	0	0	40	40	40	60	60	80	80	80	80	80	80
Cogen 2	0	0	0	0	0	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357	714	714	714
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	32	88	88	88	88
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	21	36	51	71	91	459	511	868	871	895	1252	1280	1304	1360	1717	1717	1725
Total Firm Resources	5141	5070	5018	5227	5220	5217	5319	5629	5897	5853	6184	6152	6048	6267	6246	6329	6387	6682	6612	6676
Load/Resource Balance	-221	-301	-394	-246	-306	-365	-335	-96	105	-5	273	181	20	162	57	51	26	236	76	50

Study ID :5-APR-91 13:38:40
Study Title:No Coal or Nuclear - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
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Observed Load	9398	9637	9839	10036	10240	10450	10660	10858	11048	11228	11400	11587	11780	11997	12234	12478	12706	12940	13187	13427
Observed Rate	2.54%	2.09%	2.00%	2.04%	2.04%	2.01%	1.86%	1.75%	1.63%	1.53%	1.63%	1.67%	1.84%	1.98%	1.99%	1.83%	1.84%	1.91%	1.82%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	7	21	36	53	69	86	104	123	142	163	184	204	217	222	226	228
New Commercial 1	0	2	5	11	23	40	57	75	93	112	131	151	171	192	214	234	256	278	300	324
Commercial R&R 1	0	5	11	16	21	27	32	37	43	48	53	59	64	69	75	80	85	91	96	101
New SF Res 1	0	0	2	3	6	9	13	16	20	24	27	31	35	39	43	47	51	54	58	62
New MF Res 1	0	0	0	1	1	2	2	3	3	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	5	8	13	17	22	27	33	38	43	49	54	59	65	70	75	80	85
New Res Light 1	0	0	1	1	3	4	5	7	8	9	11	12	14	15	17	18	19	21	22	23
Wtr Htr Heat Pumps	0	0	1	3	5	7	10	13	16	19	23	26	29	33	36	39	43	46	49	52
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96
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Subtotal	0	23	75	146	237	347	457	569	683	799	906	1011	1122	1235	1351	1465	1573	1671	1769	1865
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	83	83	83	83	83
Thermal Eff Imp	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	416	520	624	768	912	960	960	960	960	960	960
Wind 1	0	0	0	0	0	0	0	0	17	17	17	17	17	17	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	0	0	105	105	105	105	105	105	175	245	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	15	26	33	41	55	66	77	89	100
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32	184	264	296	312	432
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	79	119	158	198	238
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	22	33	44	55
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18	54
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	44	71	99
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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Subtotal	0	0	0	60	110	240	390	934	1437	1909	2031	2166	2333	2498	2716	3005	3204	3327	3451	3704
Total Firm Resources	9519	9554	9601	9493	9561	9727	9822	10313	10811	11279	11457	11648	11901	12125	12411	12656	12909	13141	13381	13493
Load/Resource Balance	121	-83	-237	-542	-679	-723	-837	-545	-237	51	57	62	120	127	177	178	203	201	194	66

Study ID :5-APR-91 13:38:40
Study Title:No Coal or Nuclear - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4705	4830	4935	5038	5144	5252	5361	5464	5568	5667	5754	5849	5949	6061	6183	6309	6427	6548	6676	6801
Observed Rate	2.67%	2.18%	2.09%	2.10%	2.11%	2.07%	1.92%	1.89%	1.78%	1.54%	1.64%	1.71%	1.88%	2.02%	2.04%	1.87%	1.88%	1.96%	1.86%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2260	2398	2485	2571	2693	2817	2927	2880	2999	3113	3192	3278	3389	3511	3621	3622	3675	3790	3912	3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	8	14	20	26	32	39	47	54	62	69	77	82	84	85	85
New Commercial 1	0	0	1	3	7	11	16	20	25	30	35	40	45	51	56	62	67	73	79	85
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	25	27	29	31
New MF Res 1	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	8	10	11	13	15	17	19	21	22	24	26	28	29
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	5	6	8	9	10	12	13	14	16	17	18	20
Subtotal	0	0	3	7	17	31	47	61	77	92	110	129	146	166	183	201	217	230	242	253
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4705	4831	4938	5045	5160	5283	5407	5374	5487	5596	5696	5804	5917	6041	6176	6320	6451	6578	6712	6849
Load/Resource Balance	0	1	3	7	16	31	45	-91	-81	-71	-58	-44	-32	-20	-7	11	24	30	36	49

Study ID :5-APR-91 13:38:40
Study Title:No Coal or Nuclear - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17183	17608	17949	18303	18682	19072	19464	19837	20197	20542	20869	21222	21587	21993	22438	22895	23325	23764	24230	24683
Observed Rate	2.47%	1.94%	1.97%	2.07%	2.09%	2.06%	1.91%	1.82%	1.71%	1.59%	1.69%	1.72%	1.88%	2.02%	2.04%	1.88%	1.89%	1.96%	1.87%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	13	38	65	94	123	152	185	220	255	292	328	364	388	397	403	406
New Commercial 1	0	2	7	16	34	58	82	107	133	160	187	215	243	273	304	333	363	395	426	460
Commercial R&R 1	0	8	16	24	32	40	48	56	65	72	80	89	96	104	113	120	128	137	145	152
New SF Res 1	0	0	4	7	13	19	27	33	41	49	56	64	72	80	89	97	104	111	119	127
New MF Res 1	0	0	0	1	1	4	4	5	5	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	9	14	22	30	38	47	56	65	74	84	93	102	111	120	129	138	146
New Res Light 1	0	0	1	2	5	7	9	12	13	15	18	20	23	25	28	30	32	35	37	39
Wtr Htr Heat Pumps	0	0	1	3	7	11	16	21	27	32	39	45	50	58	63	69	76	81	87	93
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	308	326
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	212	224
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	16	17	19	20	21	23	24	25	26
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	98
Subtotal	64	167	319	490	646	831	1021	1257	1449	1642	1827	2004	2186	2372	2560	2746	2921	3078	3236	3390
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	110	110	110	110	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	357	714	714	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	11	22	40	54	62	72	83	90	98	101	101	101	101	101
Thermal Eff Imp	0	0	0	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	160	280	400	420	460	460	460	480	480	500	500	500	500	500	500
Cogen 2	0	0	0	0	0	0	0	41	49	57	57	57	57	57	57	57	57	57	57	57
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	714	714	714	714	1071	1071	1071
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	38
Cogen 3	0	0	0	0	0	0	0	0	328	416	520	624	768	912	968	992	1048	1048	1048	1048
Wind 1	0	0	0	0	0	0	0	0	17	17	17	17	17	17	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	0	0	105	105	105	105	105	105	175	245	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	15	26	33	41	55	66	77	89	100
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32	184	264	296	312	432
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	79	119	158	198	238
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	22	33	44	55
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18	54
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	44	71	99
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	81	146	291	461	1025	1896	2420	2899	3037	3228	3750	3996	4309	4564	5044	5168	5429
Total Firm Resources	19365	19455	19558	19765	19942	20227	20548	21317	22195	22728	23338	23604	23866	24433	24834	25305	25747	26401	26706	27018
Load/Resource Balance	-100	-383	-628	-781	-969	-1057	-1127	-731	-213	-25	272	198	109	269	226	241	253	466	305	165

Study ID :8-APR-91 12:30:15
Study Title:No Coal or Nuclear - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3151	3260	3326	3414	3523	3631	3745	3846	3943	4045	4148	4254	4357	4468	4594	4718	4835	4955	5080	5206
Observed Rate	3.47%	2.02%	2.66%	3.17%	3.07%	3.15%	2.69%	2.53%	2.59%	2.55%	2.54%	2.43%	2.55%	2.80%	2.71%	2.48%	2.47%	2.52%	2.48%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2489	-2749	-2944	-2905	-3101	-3295	-3471	-3441	-3607	-3781	-3921	-4064	-4222	-4392	-4561	-4616	-4728	-4903	-5085	-5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	10	17	24	32	39	47	57	66	76	86	96	102	104	106	108
New Commercial 1	0	0	1	3	6	9	13	16	20	24	27	31	35	38	42	46	50	54	58	63
Commercial R&R 1	0	3	5	8	10	13	15	18	20	23	25	28	30	33	36	38	41	43	46	48
New SF Res 1	0	1	2	3	6	9	13	16	19	23	26	29	33	36	40	43	46	50	53	57
New MF Res 1	0	0	0	0	0	1	1	1	1	2	2	2	2	2	3	3	3	3	4	4
New Manuf Housing 1	0	0	1	2	3	4	6	8	9	11	13	15	16	18	20	22	23	25	27	29
New Res Light 1	0	0	1	1	2	4	5	7	8	9	11	12	13	15	16	18	19	20	22	23
Wtr Htr Heat Pumps	0	0	0	0	1	3	4	6	8	10	12	14	17	19	21	23	25	27	29	31
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	1	2	4	5	6	8	9	10	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	2	8	16	24	32	40	48	56	64	72
Subtotal	192	209	243	339	395	461	529	644	708	777	840	903	969	1034	1102	1168	1229	1285	1346	1404
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	60	75	75	75	75	75	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	357	714	714	714	714	714	714	714	714	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	4	7	11	14	14	14	14	14	14	14	14	14	14	14
Thermal Eff Imp	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	20	60	80	80	80	80	80	80	80	80	80	80	80	80	80
Cogen 2	0	0	0	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	714	1071	1071	1071	1071	1071	1071	1071	1071	1071
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	8
Cogen 3	0	0	0	0	0	0	0	0	56	112	168	168	168	168	168	168	168	168	168	168
Wind 1	0	0	0	0	0	0	0	0	0	6	6	6	6	6	6	6	6	6	6	6
Geothermal	0	0	0	0	0	0	0	0	0	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	4	4	7	11	15	18	18	18	18	18
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	40	80	80	80	80	80	80	80
Wind 2	0	0	0	0	0	0	0	0	0	0	8	8	16	24	32	40	48	55	55	55
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	4	7	11	15	15	15	15
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	18	18	18	18	18	18	18
Wind 3	0	0	0	0	0	0	0	0	0	0	0	11	16	22	27	33	38	44	44	44
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	6	21	36	71	135	543	964	1421	1846	2214	2270	2350	2370	2391	2408	2429	2429	2429
Total Firm Resources	5147	4921	4754	4895	4816	4768	4851	5536	5814	6120	6463	6747	6641	6546	6471	6509	6481	6391	6273	6274
Load/Resource Balance	-340	-653	-907	-876	-1062	-1217	-1248	-663	-482	-277	-12	192	9	-197	-397	-484	-629	-838	-1081	-1206

Study ID :8-APR-91 12:30:15
Study Title:No Coal or Nuclear - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9642	10059	10381	10709	11061	11407	11751	12045	12332	12636	12932	13232	13524	13842	14203	14557	14898	15246	15608	15970
Observed Rate	4.33%	3.20%	3.16%	3.29%	3.13%	3.01%	2.50%	2.39%	2.46%	2.34%	2.32%	2.21%	2.36%	2.60%	2.50%	2.34%	2.34%	2.37%	2.32%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	8	24	41	60	79	98	118	138	161	186	211	235	250	257	262	265
New Commercial 1	0	3	6	16	34	55	77	100	123	147	170	193	217	242	268	292	318	344	371	398
Commercial R&R 1	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95
New SF Res 1	0	1	3	6	10	16	22	28	34	40	47	53	59	66	72	79	85	91	97	104
New MF Res 1	0	0	0	1	1	2	2	3	4	5	5	6	7	7	8	9	10	10	11	12
New Manuf Housing 1	0	1	2	4	7	12	16	20	25	30	35	39	44	49	53	58	63	67	72	76
New Res Light 1	0	0	1	2	4	6	8	9	11	13	15	17	19	22	24	26	27	29	31	33
Wtr Htr Heat Pumps	0	1	2	4	7	11	15	19	24	29	34	38	43	48	53	58	62	67	72	76
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96	108
Subtotal	0	26	77	154	254	375	496	617	744	871	991	1109	1234	1360	1487	1614	1730	1837	1946	2051
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	87	87	87	87	87
Thermal Eff Imp	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	656	960	960	960	960	960	960	960	960	960	960
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	107	107	107
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	232	456	456	456	456	456	456	456	456
Wind 2	0	0	0	0	0	0	40	79	119	158	198	238	277	309	317	317	317	317	317	317
Small Hydro 4	0	0	0	0	0	0	15	29	44	58	69	76	76	76	76	76	76	76	76	76
Biomass	0	0	0	0	0	54	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Wind 3	0	0	0	0	0	0	0	0	0	0	27	55	82	110	137	165	192	209	209	209
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	50	60	110	411	748	1430	1915	2695	3110	3444	3757	3842	3885	3920	3947	3972	3972	3979
Total Firm Resources	9519	9555	9654	9501	9579	9926	10218	10859	11350	12139	12622	13025	13438	13593	13718	13718	13810	13952	14079	13955
Load/Resource Balance	-123	-505	-726	-1208	-1482	-1482	-1533	-1185	-982	-497	-310	-207	-85	-249	-484	-839	-1088	-1294	-1528	-2014

Study ID :8-APR-91 12:30:15
Study Title:No Coal or Nuclear - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4827	5043	5206	5373	5553	5730	5905	6055	6208	6369	6521	6675	6825	6989	7173	7355	7535	7719	7911	8103
Observed Rate	4.49%	3.23%	3.19%	3.35%	3.19%	3.06%	2.54%	2.52%	2.59%	2.39%	2.37%	2.24%	2.39%	2.64%	2.54%	2.45%	2.45%	2.48%	2.43%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2382	2611	2756	2905	3101	3295	3471	3441	3607	3781	3921	4064	4222	4392	4561	4616	4728	4903	5085	5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	9	16	22	29	36	44	52	61	70	79	88	94	96	98	99
New Commercial 1	0	1	2	5	10	15	21	27	33	40	45	51	58	64	71	77	84	90	97	105
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	3	5	9	12	15	18	21	24	27	30	33	37	40	43	46	49	52
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	4
New Manuf Housing 1	0	0	1	1	3	4	6	7	9	10	12	14	15	17	18	20	22	23	25	26
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	4	6	8	10	12	13	15	17	19	21	23	25	27	29
Subtotal	0	1	4	9	22	40	60	78	98	118	139	159	181	203	226	249	269	283	299	315
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4827	5045	5211	5382	5575	5770	5964	5952	6116	6288	6453	6621	6785	6962	7160	7361	7554	7745	7943	8148
Load/Resource Balance	0	1	4	10	22	40	59	-103	-92	-81	-68	-54	-41	-27	-13	6	19	26	32	45

Study ID :8-APR-91 12:30:15
Study Title:No Coal or Nuclear - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17619	18363	18913	19496	20136	20768	21401	21946	22483	23050	23601	24161	24706	25299	25970	26631	27269	27920	28598	29278
Observed Rate	4.22%	3.00%	3.08%	3.29%	3.14%	3.05%	2.54%	2.45%	2.52%	2.39%	2.37%	2.26%	2.40%	2.65%	2.55%	2.40%	2.39%	2.43%	2.38%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	14	43	74	106	140	173	209	247	288	332	376	419	446	457	466	472
New Commercial 1	0	4	9	24	50	79	111	143	176	211	242	275	310	344	381	415	452	488	526	566
Commercial R&R 1	0	8	15	23	30	38	45	53	60	68	75	83	90	98	106	113	121	128	136	143
New SF Res 1	0	2	6	12	21	34	47	59	71	84	97	109	122	135	149	162	174	187	199	213
New MF Res 1	0	0	0	1	1	4	4	5	6	8	9	10	11	11	13	15	16	16	18	20
New Manuf Housing 1	0	1	4	7	13	20	28	35	43	51	60	68	75	84	91	100	108	115	124	131
New Res Light 1	0	0	2	3	6	10	13	16	19	22	26	29	32	37	40	44	46	49	53	56
Wtr Htr Heat Pumps	0	1	2	4	9	16	23	31	40	49	58	65	75	84	93	102	110	119	128	136
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	308	326
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	212	224
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	16	17	19	20	21	23	24	25	26
High Cost Block	0	0	0	0	0	0	0	0	0	0	5	20	40	60	80	100	120	140	160	180
Subtotal	192	236	324	502	671	876	1085	1339	1550	1766	1970	2171	2384	2597	2815	3031	3228	3405	3591	3770
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	110	110	110	110	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	714	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	15	29	44	57	65	72	79	86	94	101	101	101	101	101
Thermal Eff Imp	0	0	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	180	340	480	500	500	500	500	500	500	500	500	500	500	500	500
Cogen 2	0	0	0	0	0	0	0	49	57	57	57	57	57	57	57	57	57	57	57	57
Combined Cycle 2	0	0	0	0	0	0	0	0	0	714	1071	1428	1428	1428	1428	1428	1428	1428	1428	1428
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	31	31	38
Cogen 3	0	0	0	0	0	0	0	0	384	768	1128	1128	1128	1128	1128	1128	1128	1128	1128	1128
Wind 1	0	0	0	0	0	12	23	23	23	29	29	29	29	29	29	29	29	29	29	29
Geothermal	0	0	0	0	0	105	175	245	280	315	315	315	315	315	315	315	315	315	315	315
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	78	89	103	118	122	125	125	125	125	125
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	232	496	536	536	536	536	536	536	536
Wind 2	0	0	0	0	0	0	40	79	119	158	206	246	293	333	349	357	365	372	372	372
Small Hydro 4	0	0	0	0	0	0	15	29	44	58	69	76	76	80	83	87	91	91	91	91
Biomass	0	0	0	0	0	54	90	90	90	90	90	90	90	108	108	108	108	108	108	108
Wind 3	0	0	0	0	0	0	0	0	0	0	27	66	98	132	164	198	230	253	253	253
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	56	81	146	482	883	1973	2879	4116	4956	5658	6027	6192	6255	6311	6355	6401	6401	6408
Total Firm Resources	19493	19521	19619	19778	19970	20464	21034	22348	23280	24546	25538	26393	26864	27101	27349	27588	27846	28089	28295	28377
Load/Resource Balance	-462	-1156	-1630	-2074	-2522	-2659	-2722	-1951	-1556	-856	-390	-69	-117	-473	-895	-1317	-1697	-2107	-2578	-3176

Study ID :8-APR-91 12:37:46
Study Title:60% Conservation Penetration Rate - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2934	2915	2888	2881	2892	2907	2923	2936	2948	2958	2969	2982	2995	3012	3035	3058	3081	3103	3128	3155
Observed Rate	-0.63%	-0.95%	-0.24%	0.37%	0.51%	0.55%	0.47%	0.41%	0.34%	0.36%	0.45%	0.44%	0.57%	0.74%	0.76%	0.75%	0.71%	0.80%	0.87%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2108	-2104	-2122	-1903	-1918	-1937	-1946	-1854	-1876	-1895	-1889	-1889	-1909	-1936	-1949	-1851	-1809	-1826	-1846	-1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	5	8	12	15	19	23	28	33	37	41	45	48	48	49	49
New Commercial 1	0	0	0	0	1	2	3	4	5	5	6	7	8	9	11	12	13	14	15	16
Commercial R&R 1	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
New SF Res 1	0	0	0	0	1	1	1	2	2	2	3	3	3	4	4	5	5	5	6	6
New MF Res 1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	2	2	2	2
New Manuf Housing 1	0	0	0	1	1	2	2	3	4	5	5	6	7	8	8	9	10	11	12	13
New Res Light 1	0	0	0	0	1	1	1	1	2	2	2	2	3	3	3	3	4	4	4	4
Wtr Htr Heat Pumps	0	0	0	0	0	0	1	1	1	2	2	2	3	3	3	4	4	4	5	5
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	1	4	7	10	13	16	19	22	25	25	25	25	25	25	25	25	25	25	25
Industrial 1	0	1	4	11	17	24	30	36	43	49	49	49	49	49	49	49	49	49	49	49
Irrigation 1	0	0	1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	4
T&D Effic Impr	0	2	6	9	13	16	20	24	27	31	31	31	31	31	31	31	31	31	31	31
Industrial 2	0	1	3	7	12	16	20	25	29	34	34	34	34	34	34	34	34	34	34	34
Exist. Commercial 1	0	1	4	8	13	20	27	34	41	48	48	48	48	48	48	48	48	48	48	48
MF Res Weath	0	0	1	2	3	4	5	6	7	8	8	8	8	8	8	8	8	8	8	8
SF Res Weath	0	2	6	12	17	22	28	33	38	43	43	43	43	43	43	43	43	43	43	43
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	9	31	61	97	133	171	210	249	287	294	302	312	320	327	336	344	347	353	356
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5336	5368	5360	5597	5663	5727	5886	6148	6120	6095	6103	6107	6026	5937	5940	6052	6106	6099	6090	6197
Load/Resource Balance	420	672	893	1338	1595	1846	1990	2239	2200	2288	2409	2523	2551	2445	2425	2515	2546	2517	2483	2563

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Study Title:60% Conservation Penetration Rate - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	8920	8853	8823	8795	8785	8785	8795	8797	8791	8779	8771	8772	8776	8796	8831	8867	8901	8934	8973	9019
Observed Rate	-0.75%	-0.35%	-0.32%	-0.11%	0.01%	0.11%	0.02%	-0.07%	-0.14%	-0.09%	0.02%	0.05%	0.23%	0.39%	0.41%	0.38%	0.37%	0.44%	0.51%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	4	11	19	29	38	47	58	69	79	90	100	111	116	118	119	119
New Commercial 1	0	0	1	2	6	11	17	22	28	34	40	47	53	60	67	74	81	88	96	103
Commercial R&R 1	0	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30	32	34	36	38
New SF Res 1	0	0	0	1	1	2	2	3	3	4	5	5	6	7	8	8	9	10	10	11
New MF Res 1	0	0	0	0	0	1	1	1	2	2	3	3	3	4	4	4	5	5	5	6
New Manuf Housing 1	0	0	1	2	3	5	6	8	10	12	14	16	18	21	23	25	27	29	31	33
New Res Light 1	0	0	0	0	1	1	1	2	2	3	3	3	4	4	5	5	5	6	6	6
Wtr Htr Heat Pumps	0	0	0	1	1	2	2	3	4	4	5	6	7	8	8	9	10	11	12	13
Cons. Volt. Reg.	0	2	6	11	15	19	23	27	32	36	40	42	42	42	42	42	42	42	42	42
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	81	83	83	83	83	83
Irrigation 1	0	0	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	11	12	12
T&D Effic Impr	0	1	5	8	12	15	19	22	26	29	33	36	40	43	46	50	53	57	60	63
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	57	57	57	57	57
Exist. Commercial 1	0	1	7	15	27	40	54	67	81	94	94	96	101	109	121	134	148	161	175	188
MF Res Weath	0	2	4	8	12	16	19	23	27	31	31	31	31	31	31	31	31	31	31	31
SF Res Weath	0	2	6	11	16	21	26	31	35	40	40	40	40	42	42	42	42	42	42	42
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	10	10	10	10	10	10	10	10	10	10
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	13	43	86	141	202	260	324	389	452	496	538	581	633	681	724	761	795	827	857
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	14	29	38	43	52
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	10	20	30	49	64	73	78	444
Total Firm Resources	9519	9543	9571	9374	9353	9341	9238	9136	9080	9024	9015	9007	9037	9039	9053	8958	8957	9010	9066	9226
Load/Resource Balance	599	690	749	579	568	555	443	340	289	246	245	235	260	242	222	91	56	76	93	206

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Study Title:60% Conservation Penetration Rate - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4445	4398	4384	4371	4369	4372	4380	4384	4386	4384	4383	4386	4391	4403	4424	4445	4463	4481	4502	4526
Observed Rate	-1.05%	-0.33%	-0.30%	-0.05%	0.07%	0.19%	0.09%	0.04%	-0.04%	-0.04%	0.07%	0.11%	0.29%	0.46%	0.47%	0.41%	0.40%	0.47%	0.55%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2001	1966	1934	1903	1918	1937	1946	1854	1876	1895	1889	1889	1909	1936	1949	1851	1809	1826	1846	1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	1	4	7	11	14	17	21	26	30	34	38	42	44	45	45	45
New Commercial 1	0	0	0	1	2	3	5	6	8	9	11	12	14	16	18	19	21	23	25	27
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	0	1	1	1	1	2	2	2	3	3	3	4	4	5	5	5	6
New MF Res 1	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	2	2	2
New Manuf Housing 1	0	0	0	1	1	2	2	3	4	4	5	6	6	7	8	9	9	10	11	12
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	0	1	1	1	2	2	2	2	3	3	3	4	4	4	5
Subtotal	0	0	0	2	5	10	16	22	30	35	42	50	56	64	72	78	84	89	92	97
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4445	4399	4385	4373	4374	4382	4397	4309	4316	4320	4325	4336	4347	4366	4393	4426	4452	4473	4497	4531
Load/Resource Balance	0	0	1	2	5	10	16	-75	-70	-65	-57	-50	-43	-38	-31	-19	-11	-8	-5	4

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Study Title:60% Conservation Penetration Rate - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16299	16167	16094	16047	16045	16064	16098	16118	16125	16121	16122	16140	16162	16212	16290	16370	16445	16518	16603	16701
Observed Rate	-0.81%	-0.45%	-0.30%	-0.01%	0.12%	0.21%	0.12%	0.05%	-0.03%	0.01%	0.11%	0.14%	0.31%	0.48%	0.49%	0.46%	0.44%	0.51%	0.59%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	7	20	34	52	67	83	102	123	142	161	179	198	208	211	213	213
New Commercial 1	0	0	1	3	9	16	25	32	41	48	57	66	75	85	96	105	115	125	136	146
Commercial R&R 1	0	3	6	9	12	15	18	21	24	27	30	33	36	39	42	45	48	51	54	57
New SF Res 1	0	0	0	1	3	4	4	6	7	8	10	11	12	14	16	17	19	20	21	23
New MF Res 1	0	0	0	0	0	1	1	1	4	4	5	5	5	6	6	6	8	9	9	10
New Manuf Housing 1	0	0	1	4	5	9	10	14	18	21	24	28	31	36	39	43	46	50	54	58
New Res Light 1	0	0	0	0	2	2	2	3	4	5	5	5	7	7	8	8	9	10	10	10
Wtr Htr Heat Pumps	0	0	0	1	1	2	4	5	6	8	9	10	12	14	14	16	18	19	21	23
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	3	10	18	25	32	39	46	54	61	65	67	67	67	67	67	67	67	67	67
Industrial 1	0	2	8	22	34	48	60	72	86	98	105	111	118	125	130	132	132	132	132	132
Irrigation 1	0	0	2	2	4	5	6	7	9	9	10	11	11	12	13	13	14	15	16	16
T&D Effic Impr	0	3	11	17	25	31	39	46	53	60	64	67	71	74	77	81	84	88	91	94
Industrial 2	0	2	6	14	24	32	40	50	58	68	72	77	81	86	90	91	91	91	91	91
Exist. Commercial 1	0	2	11	23	40	60	81	101	122	142	142	144	149	157	169	182	196	209	223	236
MF Res Weath	0	2	5	10	15	20	24	29	34	39	39	39	39	39	39	39	39	39	39	39
SF Res Weath	0	4	12	23	33	43	54	64	73	83	83	83	83	85	85	85	85	85	85	85
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	10	10	10	10	10	10	10	10	10	10
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	22	74	149	243	345	447	556	668	774	832	890	949	1017	1080	1138	1189	1231	1272	1310
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	5	5	5	14	29	38	43	52
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	10	20	30	49	64	73	78	444
Total Firm Resources	19300	19310	19315	19343	19389	19450	19521	19593	19516	19438	19444	19451	19410	19341	19385	19436	19515	19582	19653	19954
Load/Resource Balance	1019	1362	1642	1919	2168	2412	2449	2504	2419	2469	2596	2709	2768	2650	2617	2587	2591	2585	2571	2774

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Study Title:60% Conservation Penetration Rate - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2983	2993	2988	3004	3036	3072	3111	3147	3182	3216	3249	3284	3320	3362	3412	3464	3514	3565	3616	3670
Observed Rate 0.32%	-0.18%	0.55%	1.08%	1.18%	1.27%	1.16%	1.10%	1.07%	1.02%	1.08%	1.10%	1.26%	1.49%	1.51%	1.45%	1.43%	1.45%	1.49%		
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2191	-2243	-2303	-2128	-2178	-2233	-2278	-2202	-2258	-2313	-2343	-2376	-2429	-2492	-2545	-2488	-2489	-2550	-2612	-2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	5	9	13	18	22	27	32	38	43	48	53	56	57	58	58
New Commercial 1	0	0	0	1	2	3	4	5	6	8	9	10	12	13	14	16	17	19	20	22
Commercial R&R 1	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	22	24	25	27
New SF Res 1	0	0	0	1	1	2	3	3	4	5	6	7	8	8	9	10	11	12	12	13
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2
New Manuf Housing 1	0	0	0	1	2	3	4	5	6	7	9	10	11	12	14	15	16	17	18	19
New Res Light 1	0	0	0	1	1	1	2	2	3	3	4	4	5	6	6	7	7	8	8	8
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	2	3	3	4	4	5	6	6	7	8	8	9	10
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	1	4	7	10	13	16	19	22	25	25	25	25	25	25	25	25	25	25	25
Industrial 1	0	1	4	11	17	24	30	36	43	49	49	49	49	49	49	49	49	49	49	49
Irrigation 1	0	0	1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	4
T&D Effic Impr	0	2	6	9	13	16	20	24	27	31	31	31	31	31	31	31	31	31	31	31
Industrial 2	0	1	3	7	12	16	20	25	29	34	34	34	34	34	34	34	34	34	34	34
Exist. Commercial 1	0	1	4	8	13	20	27	34	41	48	48	48	48	48	48	48	48	48	48	48
MF Res Weath	0	0	1	2	3	4	5	6	7	8	8	8	8	8	8	8	8	8	8	8
SF Res Weath	0	2	6	12	17	22	28	33	38	43	43	43	43	43	43	43	43	43	43	43
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	9	32	65	101	139	180	221	263	304	413	520	631	642	653	665	673	681	686	693
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5252	5230	5180	5375	5406	5438	5564	5812	5752	5695	5768	5838	5824	5702	5668	5743	5756	5707	5659	5728
Load/Resource Balance	163	264	354	666	799	928	1015	1228	1134	1043	1083	1119	1069	905	822	845	809	710	610	625

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Study Title:60% Conservation Penetration Rate - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9075	9108	9161	9219	9283	9356	9441	9513	9582	9648	9713	9786	9863	9962	10084	10210	10333	10459	10583	10715
Observed Rate	0.37%	0.58%	0.64%	0.70%	0.78%	0.91%	0.77%	0.72%	0.69%	0.68%	0.75%	0.78%	1.00%	1.22%	1.25%	1.21%	1.22%	1.19%	1.24%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	4	13	22	33	44	55	67	79	91	104	117	129	137	140	142	143
New Commercial 1	0	1	2	4	9	17	24	32	40	48	56	65	73	82	91	100	110	120	129	139
Commercial R&R 1	0	3	6	8	11	14	17	19	22	25	28	30	33	36	39	41	44	47	50	52
New SF Res 1	0	0	1	1	2	3	5	6	8	9	11	12	14	15	17	18	20	21	23	24
New MF Res 1	0	0	0	0	1	1	1	2	2	3	3	4	4	5	5	6	6	7	7	7
New Manuf Housing 1	0	0	1	2	4	7	10	13	16	20	23	26	29	33	36	39	42	45	49	52
New Res Light 1	0	0	0	1	1	2	3	4	4	5	6	7	7	8	9	9	10	11	11	12
Wtr Htr Heat Pumps	0	0	1	1	2	3	4	6	7	9	10	12	13	15	16	18	19	21	22	24
Cons. Volt. Reg.	0	2	6	11	15	19	23	27	32	36	40	42	42	42	42	42	42	42	42	42
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	101	104	104
Irrigation 1	0	0	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	11	12	12
T&D Effic Impr	0	1	5	8	12	15	19	22	26	29	33	36	40	43	46	50	53	57	60	63
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	61	65	67	67	67
Exist. Commercial 1	0	1	7	15	27	40	54	67	81	94	108	121	135	148	162	175	188	202	215	229
MF Res Weath	0	2	4	8	12	16	19	23	27	31	31	31	31	31	31	31	31	31	31	31
SF Res Weath	0	2	6	11	16	21	26	31	35	40	42	42	42	42	42	42	42	42	42	42
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	10	10	10	10	11	11	11	11	11	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	48	91	151	219	286	357	429	502	568	629	687	750	811	870	925	976	1017	1054
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	38	48	57	67	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	14	14	25	36	43	51	58	65	72	80	87	87	87
Thermal Eff Imp	0	0	0	0	0	0	13	13	13	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	0	80	120	160	220	300	400	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	8	8	8	8	41	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160	256	304	360	360
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	25	73	448	457	595	655	720	797	884	991	1219	1338	1401	1457	1821
Total Firm Resources	9519	9545	9575	9386	9380	9384	9335	9616	9577	9667	9741	9817	9930	10022	10146	10275	10396	10517	10635	10799
Load/Resource Balance	444	437	414	167	97	28	-105	103	-5	19	28	31	67	60	62	65	63	58	51	85

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Study Title:60% Conservation Penetration Rate - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4529	4537	4565	4596	4630	4668	4712	4751	4788	4824	4860	4899	4938	4989	5051	5115	5179	5243	5308	5376
Observed Rate	0.18%	0.61%	0.67%	0.74%	0.82%	0.95%	0.82%	0.79%	0.75%	0.74%	0.80%	0.80%	1.02%	1.25%	1.27%	1.24%	1.25%	1.23%	1.28%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2084	2105	2115	2128	2178	2233	2278	2202	2258	2313	2343	2376	2429	2492	2545	2488	2489	2550	2612	2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	5	8	12	16	20	25	30	35	39	44	49	52	53	53	54
New Commercial 1	0	0	0	1	3	5	7	9	11	13	15	17	19	22	24	26	29	31	34	37
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	1	1	2	2	3	4	5	5	6	7	8	9	9	10	11	11	12
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2
New Manuf Housing 1	0	0	0	1	2	2	3	5	6	7	8	9	10	11	12	14	15	16	17	18
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9
Subtotal	0	0	0	3	8	15	21	32	40	49	58	67	77	86	97	107	115	121	125	132
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4529	4538	4566	4599	4637	4683	4735	4666	4709	4751	4794	4841	4888	4945	5014	5091	5162	5230	5297	5374
Load/Resource Balance	0	0	1	3	7	15	23	-85	-79	-73	-66	-57	-50	-44	-37	-25	-17	-14	-11	-2

Study ID :5-APR-91 13:28:55
Study Title:60% Conservation Penetration Rate - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16587	16638	16713	16819	16949	17096	17264	17412	17552	17688	17822	17969	18121	18312	18547	18789	19026	19267	19508	19760
Observed Rate	0.31%	0.45%	0.63%	0.78%	0.87%	0.98%	0.85%	0.81%	0.77%	0.76%	0.83%	0.85%	1.05%	1.28%	1.31%	1.26%	1.27%	1.25%	1.30%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	8	23	39	58	78	97	119	141	164	186	209	231	245	250	253	255
New Commercial 1	0	1	2	6	14	25	35	46	57	69	80	92	104	117	129	142	156	170	183	198
Commercial R&R 1	0	4	9	12	17	21	25	29	33	38	42	45	50	54	59	62	66	71	75	79
New SF Res 1	0	0	1	3	4	7	10	12	16	19	22	25	29	31	35	37	41	44	46	49
New MF Res 1	0	0	0	0	1	1	1	4	4	5	5	6	6	8	9	10	10	11	11	11
New Manuf Housing 1	0	0	1	4	8	12	17	23	28	34	40	45	50	56	62	68	73	78	84	89
New Res Light 1	0	0	0	2	2	3	5	6	7	8	10	11	12	14	15	16	17	19	19	20
Wtr Htr Heat Pumps	0	0	1	1	2	5	6	10	12	15	18	20	23	26	28	32	34	37	39	43
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	3	10	18	25	32	39	46	54	61	65	67	67	67	67	67	67	67	67	67
Industrial 1	0	2	8	22	34	48	60	72	86	98	105	111	118	125	131	138	144	150	153	153
Irrigation 1	0	0	2	2	4	5	6	7	9	9	10	11	11	12	13	13	14	15	16	16
T&D Effic Impr	0	3	11	17	25	31	39	46	53	60	64	67	71	74	77	81	84	88	91	94
Industrial 2	0	2	6	14	24	32	40	50	58	68	72	77	81	86	90	95	99	101	101	101
Exist. Commercial 1	0	2	11	23	40	60	81	101	122	142	156	169	183	196	210	223	236	250	263	277
MF Res Weath	0	2	5	10	15	20	24	29	34	39	39	39	39	39	39	39	39	39	39	39
SF Res Weath	0	4	12	23	33	43	54	64	73	83	85	85	85	85	85	85	85	85	85	85
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	10	10	10	10	11	11	11	11	11	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	24	80	159	260	373	487	610	732	855	1039	1216	1395	1478	1561	1642	1713	1778	1828	1879
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	38	48	57	67	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	14	14	25	36	43	51	58	65	72	80	87	87	87
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	13	13	13	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	0	80	120	160	220	300	400	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	8	8	8	8	41	49	49	49	49
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	160	256	304	360	360
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	25	73	448	457	595	655	720	797	884	991	1219	1338	1401	1457	1821
Total Firm Resources	19300	19312	19321	19359	19423	19504	19634	20094	20038	20112	20303	20497	20642	20668	20828	21108	21314	21454	21590	21901
Load/Resource Balance	607	701	769	836	903	971	933	1246	1050	988	1045	1092	1086	922	847	886	855	754	650	708

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Study Title:60% Conservation Penetration Rate - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3028	3063	3082	3117	3160	3207	3261	3313	3365	3415	3464	3514	3566	3623	3689	3759	3829	3899	3969	4041
Observed Rate	1.16%	0.63%	1.12%	1.39%	1.51%	1.68%	1.60%	1.56%	1.48%	1.42%	1.46%	1.46%	1.62%	1.82%	1.88%	1.87%	1.83%	1.80%	1.80%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2273	-2384	-2489	-2347	-2426	-2510	-2584	-2522	-2606	-2687	-2740	-2795	-2874	-2964	-3043	-3015	-3045	-3135	-3223	-3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	10	14	18	23	28	34	40	45	50	56	59	60	61	62
New Commercial 1	0	0	0	1	2	4	5	7	8	10	12	13	15	17	19	21	22	24	26	28
Commercial R&R 1	0	2	3	5	7	9	10	12	14	15	17	19	21	22	24	26	27	29	31	33
New SF Res 1	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	17	18
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2	2
New Manuf Housing 1	0	0	1	1	2	3	4	6	7	8	9	11	12	13	15	16	17	18	20	21
New Res Light 1	0	0	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	2	3	4	5	6	6	7	8	9	10	10	11	12
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	1	4	7	10	13	16	19	22	25	27	29	29	29	29	29	29	29	29	29
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	102	107	109
Irrigation 1	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9
T&D Effic Impr	0	2	6	9	13	16	20	24	27	31	34	38	42	46	49	53	57	60	64	68
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	61	66	70	74	76
Exist. Commercial 1	0	1	4	8	13	20	27	34	41	48	55	61	68	75	82	89	95	102	109	116
MF Res Weath	0	0	1	2	3	4	5	6	7	8	9	9	9	9	9	9	9	9	9	9
SF Res Weath	0	2	6	12	17	22	28	33	38	43	45	45	45	45	45	45	45	45	45	45
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	10	33	66	103	145	284	425	564	606	646	682	718	754	788	825	855	884	915	938
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	15	30	45	60	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357	714	714	714
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	4	4	4	4	4	4	4	4
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	15	30	45	65	89	450	450	450	450	807	807	807
Total Firm Resources	5171	5089	4995	5157	5162	5165	5361	5693	5720	5653	5650	5645	5555	5792	5755	5824	5832	6136	6082	6142
Load/Resource Balance	-41	-127	-210	-52	-60	-74	98	378	353	236	184	129	-12	167	64	63	2	235	111	99

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Study Title:60% Conservation Penetration Rate - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9222	9357	9496	9618	9731	9856	9995	10127	10253	10372	10488	10609	10738	10891	11067	11253	11438	11624	11806	11990
Observed Rate	1.46%	1.49%	1.28%	1.18%	1.28%	1.41%	1.32%	1.25%	1.16%	1.12%	1.16%	1.22%	1.42%	1.61%	1.68%	1.64%	1.63%	1.56%	1.56%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	4	13	24	35	46	58	70	83	96	109	123	137	145	148	151	152
New Commercial 1	0	1	3	6	12	22	31	41	52	62	73	84	95	107	118	130	142	155	167	180
Commercial R&R 1	0	3	7	10	14	17	20	24	27	30	34	37	41	44	47	51	54	58	61	64
New SF Res 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	26	28	30	32
New MF Res 1	0	0	0	0	1	1	2	2	2	3	3	4	4	5	5	6	6	7	7	7
New Manuf Housing 1	0	0	1	3	5	8	11	15	18	22	25	29	32	36	39	43	46	49	52	56
New Res Light 1	0	0	1	1	2	3	4	4	5	6	7	8	9	10	10	11	12	13	13	14
Wtr Htr Heat Pumps	0	0	1	2	3	4	5	7	9	11	13	15	16	18	20	22	24	26	28	29
Cons. Volt. Reg.	0	2	6	11	15	19	23	27	32	36	40	42	42	42	42	42	42	42	42	42
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	102	107	109
Irrigation 1	0	0	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	11	12	12
T&D Effic Impr	0	1	5	8	12	15	19	22	26	29	33	36	40	43	46	50	53	57	60	63
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	61	66	70	74	76
Exist. Commercial 1	0	1	7	15	27	40	54	67	81	94	108	121	135	148	162	175	188	202	215	229
MF Res Weath	0	2	4	8	12	16	19	23	27	31	31	31	31	31	31	31	31	31	31	31
SF Res Weath	0	2	6	11	16	21	26	31	35	40	42	42	42	42	42	42	42	42	42	42
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	11	11	11	11	11	11	11	11	11	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	0	15	51	98	161	232	304	378	455	532	604	671	735	802	865	934	993	1052	1103	1151
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	52	62	71	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	43	51	58	65	72	80	87	87	87	87
Thermal Eff Imp	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	380	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	8	41	41	41	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	120	120	120	120	224	344	488	744	904	960	960	960
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	17	29	29
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	105	140
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	30	44	59	74
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	105	235	390	881	1099	1475	1475	1501	1629	1768	1919	2198	2386	2510	2607	2970
Total Firm Resources	9519	9546	9578	9391	9478	9607	9670	10071	10245	10579	10599	10640	10809	10957	11130	11315	11511	11702	11871	12046
Load/Resource Balance	296	189	81	-227	-253	-249	-324	-56	-8	207	111	30	70	66	63	62	74	79	66	56

Study ID :8-APR-91 12:37:03
Study Title:60% Conservation Penetration Rate - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4611	4678	4751	4815	4877	4945	5018	5088	5155	5218	5277	5340	5406	5485	5575	5670	5764	5859	5951	6045
Observed Rate	1.46%	1.55%	1.35%	1.29%	1.39%	1.48%	1.39%	1.31%	1.22%	1.14%	1.18%	1.24%	1.45%	1.64%	1.71%	1.66%	1.64%	1.58%	1.58%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2166	2246	2301	2347	2426	2510	2584	2522	2606	2687	2740	2795	2874	2964	3043	3015	3045	3135	3223	3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	5	9	13	17	21	26	31	36	41	46	51	55	56	57	57
New Commercial 1	0	0	1	2	3	6	9	11	14	17	19	22	25	28	31	34	37	41	44	47
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	1	2	3	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2
New Manuf Housing 1	0	0	1	1	2	3	4	5	6	8	9	10	11	12	14	15	16	17	18	19
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	2	3	4	4	5	6	7	7	8	9	10	10	11
Subtotal	0	0	2	4	9	18	26	36	46	57	66	77	88	99	111	122	132	140	146	152
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4611	4679	4753	4819	4886	4963	5045	4992	5064	5133	5200	5271	5344	5429	5526	5634	5736	5833	5928	6031
Load/Resource Balance	0	1	2	4	9	18	27	-96	-91	-85	-77	-69	-62	-56	-49	-36	-28	-26	-23	-14

Study ID :8-APR-91 12:37:03
Study Title:60% Conservation Penetration Rate - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16861	17098	17329	17550	17768	18008	18274	18529	18773	19005	19229	19463	19710	19999	20332	20682	21031	21382	21726	22076
Observed Rate	1.41%	1.35%	1.27%	1.25%	1.35%	1.48%	1.39%	1.32%	1.23%	1.18%	1.22%	1.27%	1.47%	1.66%	1.72%	1.69%	1.67%	1.61%	1.61%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	8	24	43	62	81	102	124	148	172	195	219	244	259	264	269	271
New Commercial 1	0	1	4	9	17	32	45	59	74	89	104	119	135	152	168	185	201	220	237	255
Commercial R&R 1	0	5	10	15	21	26	30	36	41	45	51	56	62	66	71	77	81	87	92	97
New SF Res 1	0	0	1	4	7	11	14	17	21	25	29	33	37	41	45	49	53	57	62	66
New MF Res 1	0	0	0	0	1	1	3	4	4	5	5	6	6	8	9	10	10	11	11	11
New Manuf Housing 1	0	0	3	5	9	14	19	26	31	38	43	50	55	61	68	74	79	84	90	96
New Res Light 1	0	0	1	2	3	5	6	7	9	10	12	13	15	17	17	19	20	22	22	23
Wtr Htr Heat Pumps	0	0	1	2	3	6	8	11	15	19	22	26	28	32	35	39	43	46	49	52
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	3	10	18	25	32	39	46	54	61	67	71	71	71	71	71	71	71	71	71
Industrial 1	0	2	8	22	34	48	60	72	86	98	112	124	138	152	164	178	190	204	214	218
Irrigation 1	0	0	2	2	4	5	6	7	9	9	11	12	13	14	16	16	18	19	21	21
T&D Effic Impr	0	3	11	17	25	31	39	46	53	60	67	74	82	89	95	103	110	117	124	131
Industrial 2	0	2	6	14	24	32	40	50	58	68	76	86	94	104	112	122	132	140	148	152
Exist. Commercial 1	0	2	11	23	40	60	81	101	122	142	163	182	203	223	244	264	283	304	324	345
MF Res Weath	0	2	5	10	15	20	24	29	34	39	40	40	40	40	40	40	40	40	40	40
SF Res Weath	0	4	12	23	33	43	54	64	73	83	87	87	87	87	87	87	87	87	87	87
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	11	11	11	11	11	11	11	11	11	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	0	25	86	168	273	395	614	839	1065	1195	1316	1430	1541	1655	1764	1881	1980	2076	2164	2241
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	50	65	80	95	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	52	67	81	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	714	714	714	714	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	43	51	62	69	76	84	91	91	91	91
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	380	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	8	41	41	41	49	49	49	49	49	49	49	49	49
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	120	120	120	120	224	344	488	744	904	960	960	960
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	17	29	29
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	105	140
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	30	44	59	74
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	105	235	390	881	1114	1505	1520	1566	1718	2218	2369	2648	2836	3317	3414	3777
Total Firm Resources	19300	19314	19326	19368	19527	19735	20076	20756	21029	21365	21448	21556	21708	22178	22411	22773	23080	23671	23882	24219
Load/Resource Balance	255	62	-127	-275	-304	-305	-200	226	254	358	218	91	-4	176	78	90	47	288	153	141

Study ID :5-APR-91 13:27:55
Study Title:60% Conservation Penetration Rate - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3080	3141	3175	3229	3298	3370	3443	3514	3582	3647	3715	3787	3858	3935	4020	4107	4191	4276	4367	4456
Observed Rate	1.98%	1.09%	1.68%	2.14%	2.18%	2.18%	2.05%	1.93%	1.83%	1.85%	1.95%	1.87%	2.00%	2.15%	2.17%	2.04%	2.03%	2.12%	2.04%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2367	-2536	-2673	-2571	-2693	-2817	-2927	-2880	-2999	-3113	-3192	-3278	-3389	-3511	-3621	-3622	-3675	-3790	-3912	-3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	10	15	20	24	30	36	42	47	53	59	62	64	65	65
New Commercial 1	0	0	1	1	3	5	7	9	11	13	15	17	19	21	24	26	29	31	33	36
Commercial R&R 1	0	2	4	6	8	10	11	13	15	17	19	21	23	25	27	29	30	32	34	36
New SF Res 1	0	0	1	1	2	4	5	6	8	9	11	12	14	15	17	18	19	21	22	24
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2	2
New Manuf Housing 1	0	0	1	1	2	3	5	6	7	9	10	11	13	14	16	17	18	20	21	23
New Res Light 1	0	0	0	1	2	2	3	4	4	5	6	6	7	8	8	9	10	10	11	11
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	1	4	7	10	13	16	19	22	25	27	29	29	29	29	29	29	29	29	29
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	102	108	115
Irrigation 1	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9
T&D Effic Impr	0	2	6	9	13	16	20	24	27	31	34	38	42	46	49	53	57	60	64	68
Industrial 2	0	1	3	7	12	16	20	25	29	34	37	40	44	48	53	57	62	67	71	76
Exist. Commercial 1	0	1	4	8	13	20	27	34	41	48	54	59	65	72	79	85	92	99	106	113
MF Res Weath	0	0	1	2	3	4	5	6	7	8	9	9	9	9	9	9	9	9	9	9
SF Res Weath	0	2	6	12	17	22	28	33	38	43	45	45	45	45	45	45	45	45	45	45
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	1	2	3	3	4	5	6	7	8
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	64	138	228	309	349	390	435	529	573	617	657	691	730	767	805	841	876	910	942	976
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	60	60	70	70	70	75	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	357	357	714	714	714	714	714	714	714	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	0	0	4	7	7	7	7	7	7	7	7	11	14	14
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	0	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	80	80
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8	8
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	15	30	45	71	433	451	811	811	816	1684	1684	1684	1684	1684	1736	1779	2136
Total Firm Resources	5141	5065	5003	5193	5170	5149	5240	5873	5772	6018	5974	5923	6646	6492	6428	6470	6458	6434	6394	6792
Load/Resource Balance	-222	-306	-409	-280	-356	-433	-415	148	-20	161	62	-48	618	387	238	193	97	-12	-142	166

Study ID :5-APR-91 13:27:55
Study Title:60% Conservation Penetration Rate - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9398	9637	9839	10036	10240	10450	10660	10858	11048	11228	11400	11587	11780	11997	12234	12478	12706	12940	13187	13427
Observed Rate	2.54%	2.09%	2.00%	2.04%	2.04%	2.01%	1.86%	1.75%	1.63%	1.53%	1.63%	1.67%	1.84%	1.98%	1.99%	1.83%	1.84%	1.91%	1.82%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	5	15	25	37	49	61	73	87	101	115	130	144	153	157	159	161
New Commercial 1	0	1	3	8	16	28	40	53	66	79	93	107	121	135	150	165	181	197	213	229
Commercial R&R 1	0	4	8	11	15	19	23	26	30	34	38	41	45	49	53	56	60	64	68	71
New SF Res 1	0	0	1	2	4	7	9	12	14	17	19	22	25	28	30	33	36	38	41	44
New MF Res 1	0	0	0	0	1	1	2	2	2	3	3	4	4	5	5	6	6	7	7	7
New Manuf Housing 1	0	0	1	3	6	9	12	16	19	23	27	30	34	38	42	46	49	53	56	60
New Res Light 1	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	16
Wtr Htr Heat Pumps	0	0	1	2	3	5	7	9	11	14	16	18	21	23	25	28	30	32	35	37
Cons. Volt. Reg.	0	2	6	11	15	19	23	27	32	36	40	42	42	42	42	42	42	42	42	42
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	102	108	115
Irrigation 1	0	0	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	11	12	12
T&D Effic Impr	0	1	5	8	12	15	19	22	26	29	33	36	40	43	46	50	53	57	60	63
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	61	66	70	75	79
Exist. Commercial 1	0	1	7	15	27	40	54	67	81	94	108	121	135	148	162	175	188	202	215	229
MF Res Weath	0	2	4	8	12	16	19	23	27	31	31	31	31	31	31	31	31	31	31	31
SF Res Weath	0	2	6	11	16	21	26	31	35	40	42	42	42	42	42	42	42	42	42	42
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	11	11	11	11	11	11	11	11	11	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	0	16	52	101	169	246	322	402	483	566	642	713	785	857	928	1001	1067	1131	1191	1251
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	87	87	87	87	87
Thermal Eff Imp	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	456	584	728	896	960	960	960	960	960	960	960
Wind 1	0	0	0	0	0	0	17	29	29	29	29	29	29	29	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	105	175	245	245	245	245	245	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	0	0	15	26	33	37	37	52	63	74	85	96	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298	597	895	895	1194	1492
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	60	110	240	512	1138	1604	2127	2280	2444	2624	2752	3069	3386	3695	3714	4024	4329
Total Firm Resources	9519	9546	9580	9451	9492	9626	9812	10351	10778	11263	11440	11626	11853	11997	12341	12571	12895	12985	13375	13504
Load/Resource Balance	121	-90	-259	-585	-748	-824	-848	-507	-270	35	40	40	72	-1	107	93	189	45	187	77

Study ID :5-APR-91 13:27:55
Study Title:60% Conservation Penetration Rate - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4705	4830	4935	5038	5144	5252	5361	5464	5568	5667	5754	5849	5949	6061	6183	6309	6427	6548	6676	6801
Observed Rate	2.67%	2.18%	2.09%	2.10%	2.11%	2.07%	1.92%	1.89%	1.78%	1.54%	1.64%	1.71%	1.88%	2.02%	2.04%	1.87%	1.88%	1.96%	1.86%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2260	2398	2485	2571	2693	2817	2927	2880	2999	3113	3192	3278	3389	3511	3621	3622	3675	3790	3912	3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	10	14	18	22	27	33	38	44	49	54	58	59	60	60
New Commercial 1	0	0	1	2	5	8	11	14	18	21	25	28	32	36	40	44	48	52	56	60
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	1	2	4	5	6	7	9	10	11	13	14	15	17	18	19	21	22
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2
New Manuf Housing 1	0	0	1	1	2	3	4	5	7	8	9	11	12	13	14	16	17	18	20	21
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	3	4	5	5	6	7	8	9	10	11	12	13	14
Subtotal	0	0	3	4	11	22	32	43	55	66	77	90	103	116	129	143	154	162	172	179
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4705	4831	4938	5043	5156	5274	5393	5356	5464	5568	5664	5766	5874	5992	6122	6261	6387	6511	6641	6775
Load/Resource Balance	0	1	2	5	11	22	32	-109	-104	-98	-90	-82	-75	-69	-61	-48	-40	-37	-35	-26

Study ID :5-APR-91 13:27:55
Study Title:60% Conservation Penetration Rate - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17183	17608	17949	18303	18682	19072	19464	19837	20197	20542	20869	21222	21587	21993	22438	22895	23325	23764	24230	24683
Observed Rate	2.47%	1.94%	1.97%	2.07%	2.09%	2.06%	1.91%	1.82%	1.71%	1.59%	1.69%	1.72%	1.88%	2.02%	2.04%	1.88%	1.89%	1.96%	1.87%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	9	27	45	66	87	107	130	156	181	206	232	257	273	280	284	286
New Commercial 1	0	1	5	11	24	41	58	76	95	113	133	152	172	192	214	235	258	280	302	325
Commercial R&R 1	0	6	12	17	23	29	34	39	45	51	57	62	68	74	80	85	90	96	102	107
New SF Res 1	0	0	3	4	8	15	19	24	29	35	40	45	52	57	62	68	73	78	84	90
New MF Res 1	0	0	0	0	1	1	3	4	4	5	5	6	6	8	9	10	10	11	11	11
New Manuf Housing 1	0	0	3	5	10	15	21	27	33	40	46	52	59	65	72	79	84	91	97	104
New Res Light 1	0	0	1	2	4	5	7	9	10	12	14	15	17	19	20	22	24	25	27	27
Wtr Htr Heat Pumps	0	0	1	2	4	7	11	15	19	24	27	31	36	40	44	49	53	57	62	66
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	3	10	18	25	32	39	46	54	61	67	71	71	71	71	71	71	71	71	71
Industrial 1	0	2	8	22	34	48	60	72	86	98	112	124	138	152	164	178	190	204	216	230
Irrigation 1	0	0	2	2	4	5	6	7	9	9	11	12	13	14	16	16	18	19	21	21
T&D Effic Impr	0	3	11	17	25	31	39	46	53	60	67	74	82	89	95	103	110	117	124	131
Industrial 2	0	2	6	14	24	32	40	50	58	68	75	83	91	100	109	118	128	137	146	155
Exist. Commercial 1	0	2	11	23	40	60	81	101	122	142	162	180	200	220	241	260	280	301	321	342
MF Res Weath	0	2	5	10	15	20	24	29	34	39	40	40	40	40	40	40	40	40	40	40
SF Res Weath	0	4	12	23	33	43	54	64	73	83	87	87	87	87	87	87	87	87	87	87
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	11	12	13	14	14	15	16	17	18	19
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Subtotal	64	154	283	414	529	658	789	974	1111	1249	1376	1494	1618	1740	1862	1985	2097	2203	2305	2406
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	95	105	105	105	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	714	714	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	11	22	37	50	58	65	72	79	87	94	94	98	101	101
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	0	50	50	50	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	460	500	500
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	57	57	57
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	714
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	456	584	728	896	960	960	960	960	960	960	960
Wind 1	0	0	0	0	0	0	17	29	29	29	29	29	29	29	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	105	175	245	245	245	245	245	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	0	0	15	26	33	37	37	52	63	74	85	96	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298	597	895	895	1194	1492
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	75	140	285	583	1571	2055	2938	3091	3260	4308	4436	4753	5070	5379	5450	5803	6465
Total Firm Resources	19364	19443	19521	19687	19818	20049	20444	21580	22014	22850	23077	23315	24373	24481	24891	25302	25740	25930	26410	27071
Load/Resource Balance	-101	-395	-666	-860	-1093	-1235	-1231	-467	-394	97	11	-90	616	318	284	238	246	-4	10	217

Study ID :8-APR-91 12:36:21
Study Title:60% Conservation Penetration Rate - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3151	3260	3326	3414	3523	3631	3745	3846	3943	4045	4148	4254	4357	4468	4594	4718	4835	4955	5080	5206
Observed Rate	3.47%	2.02%	2.66%	3.17%	3.07%	3.15%	2.69%	2.53%	2.59%	2.55%	2.54%	2.43%	2.55%	2.80%	2.71%	2.48%	2.47%	2.52%	2.48%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2489	-2749	-2944	-2905	-3101	-3295	-3471	-3441	-3607	-3781	-3921	-4064	-4222	-4392	-4561	-4616	-4728	-4903	-5085	-5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	12	17	22	28	33	40	47	54	61	68	72	74	75	76
New Commercial 1	0	0	1	2	4	7	9	11	14	17	19	22	24	27	30	33	36	39	42	45
Commercial R&R 1	0	2	4	5	7	9	11	13	14	16	18	20	21	23	25	27	29	30	32	34
New SF Res 1	0	0	1	2	4	7	9	11	14	16	18	21	23	26	28	30	33	35	37	40
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3	3
New Manuf Housing 1	0	0	1	1	2	3	4	5	7	8	9	10	12	13	14	15	17	18	19	20
New Res Light 1	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	15	16
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	6	7	9	10	12	13	15	16	18	19	20	22
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	1	4	7	10	13	16	19	22	25	27	29	29	29	29	29	29	29	29	29
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	102	108	115
Irrigation 1	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9
T&D Effic Impr	0	2	6	9	13	16	20	24	27	31	34	38	42	46	49	53	57	60	64	68
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	61	66	70	75	79
Exist. Commercial 1	0	1	4	8	13	20	27	34	41	48	55	61	68	75	82	89	95	102	109	116
MF Res Weath	0	0	1	2	3	4	5	6	7	8	9	9	9	9	9	9	9	9	9	9
SF Res Weath	0	2	6	12	17	22	28	33	38	43	45	45	45	45	45	45	45	45	45	45
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	1	2	3	3	4	5	6	7	8
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	6	11	17	22	28
Subtotal	192	202	229	310	351	397	444	539	587	634	676	718	760	802	842	888	933	972	1012	1054
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	60	75	75	75	75	75	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14	14	14	14	14	14	14	14	14	14	14
Combined Cycle 1	0	0	0	0	0	0	0	357	714	714	714	714	714	714	714	714	714	714	714	714
Small Hydro 2	0	0	0	0	0	0	4	7	7	11	11	11	11	14	14	14	14	14	14	14
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	20	60	80	80	80	80	80	80	80	80	80	80	80	80	80
Cogen 2	0	0	0	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8	8
WNP 1	0	0	0	0	0	0	0	0	0	0	818	818	818	818	818	818	818	818	818	818
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	714	714	1071	1071	1071
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	8
Cogen 3	0	0	0	0	0	0	0	0	0	56	56	56	56	56	112	112	112	112	168	168
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	6
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	35
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	7
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	48
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16	40
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	21	36	71	135	543	1772	1832	2650	2650	2650	3010	3066	3423	3423	3780	3913	3985
Total Firm Resources	5147	4916	4733	4866	4771	4704	4768	5434	6500	6388	7105	6998	6811	6972	6909	7262	7199	7428	7424	7481
Load/Resource Balance	-340	-658	-928	-905	-1107	-1282	-1331	-765	204	-9	630	444	179	229	40	269	89	198	70	1

Study ID :8-APR-91 12:36:21
Study Title:60% Conservation Penetration Rate - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9642	10059	10381	10709	11061	11407	11751	12045	12332	12636	12932	13232	13524	13842	14203	14557	14898	15246	15608	15970
Observed Rate	4.33%	3.20%	3.16%	3.29%	3.13%	3.01%	2.50%	2.39%	2.46%	2.34%	2.32%	2.21%	2.36%	2.60%	2.50%	2.34%	2.34%	2.37%	2.32%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	17	29	43	56	69	83	97	113	131	149	166	176	181	185	187
New Commercial 1	0	2	5	11	24	39	54	70	86	103	119	136	154	171	189	207	226	245	264	283
Commercial R&R 1	0	4	7	11	14	18	21	25	28	32	35	39	42	46	50	53	57	60	64	67
New SF Res 1	0	1	2	4	7	11	16	20	24	29	33	37	42	46	51	56	60	64	69	73
New MF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8
New Manuf Housing 1	0	0	1	3	5	8	11	14	18	21	24	28	31	34	38	41	44	47	51	54
New Res Light 1	0	0	1	2	3	5	6	7	9	10	12	13	14	16	17	19	20	22	22	23
Wtr Htr Heat Pumps	0	0	1	3	5	8	10	14	17	20	24	27	30	34	37	41	44	47	51	54
Cons. Volt. Reg.	0	2	6	11	15	19	23	27	32	36	40	42	42	42	42	42	42	42	42	42
Industrial 1	0	1	4	11	17	24	30	36	43	49	56	62	69	76	82	89	95	102	108	115
Irrigation 1	0	0	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	11	12	12
T&D Effic Impr	0	1	5	8	12	15	19	22	26	29	33	36	40	43	46	50	53	57	60	63
Industrial 2	0	1	3	7	12	16	20	25	29	34	38	43	47	52	56	61	66	70	75	79
Exist. Commercial 1	0	1	7	15	27	40	54	67	81	94	108	121	135	148	162	175	188	202	215	229
MF Res Weath	0	2	4	8	12	16	19	23	27	31	31	31	31	31	31	31	31	31	31	31
SF Res Weath	0	2	6	11	16	21	26	31	35	40	42	42	42	42	42	42	42	42	42	42
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	11	11	11	11	11	11	11	11	11	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	2	8	17	25	34	42	50	59	67	76
Subtotal	0	18	54	108	182	266	349	437	527	615	701	784	872	961	1052	1141	1222	1300	1377	1449
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	87	87	87	87	87
Thermal Eff Imp	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Cogen 2	0	0	0	0	0	0	0	41	49	49	49	49	49	49	49	49	49	49	49	49
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Cogen 3	0	0	0	0	0	0	0	0	328	656	840	960	960	960	960	960	960	960	960	960
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	107	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	597	895	895	1194	1492	1790	1790	1790	1790	1790	1790
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	72	72	224	416	456	456	456	456
E. Wash Coal Gas	0	0	0	0	0	0	262	262	262	262	262	262	262	262	262	262	523	785	785	785
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	523	785
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	24
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	50	60	110	357	865	1494	1924	3248	3763	3910	4304	4627	5085	5284	5585	5855	6378	6671
Total Firm Resources	9519	9547	9632	9456	9505	9763	10191	10741	11141	12434	12982	13164	13620	13977	14480	14609	14941	15297	15915	16044
Load/Resource Balance	-123	-512	-749	-1252	-1556	-1645	-1560	-1303	-1192	-202	50	-68	97	135	277	51	43	50	307	74

Study ID :8-APR-91 12:36:21
Study Title:60% Conservation Penetration Rate - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4827	5043	5206	5373	5553	5730	5905	6055	6208	6369	6521	6675	6825	6989	7173	7355	7535	7719	7911	8103
Observed Rate	4.49%	3.23%	3.19%	3.35%	3.19%	3.06%	2.54%	2.52%	2.59%	2.39%	2.37%	2.24%	2.39%	2.64%	2.54%	2.45%	2.45%	2.48%	2.43%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2382	2611	2756	2905	3101	3295	3471	3441	3607	3781	3921	4064	4222	4392	4561	4616	4728	4903	5085	5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	11	16	21	25	31	37	43	50	56	62	66	68	69	70
New Commercial 1	0	1	1	3	7	11	15	19	23	28	32	36	41	45	50	55	60	64	69	74
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	2	4	6	8	10	12	15	17	19	21	24	26	28	30	32	35	37
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	1	2	2	2	2	2	2	3
New Manuf Housing 1	0	0	1	1	2	3	4	5	6	7	8	10	11	12	13	14	15	16	18	19
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	5	7	8	9	11	12	14	15	16	18	19	20
Subtotal	0	1	3	6	16	28	42	55	68	83	97	112	128	145	161	176	189	200	212	223
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4827	5045	5209	5379	5568	5758	5947	5929	6087	6253	6412	6574	6731	6902	7093	7288	7476	7663	7855	8056
Load/Resource Balance	0	1	3	7	16	28	42	-126	-121	-116	-109	-101	-94	-87	-80	-67	-59	-57	-56	-47

Study ID :8-APR-91 12:36:21
Study Title:60% Conservation Penetration Rate - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17619	18363	18913	19496	20136	20768	21401	21946	22483	23050	23601	24161	24706	25299	25970	26631	27269	27920	28598	29278
Observed Rate	4.22%	3.00%	3.08%	3.29%	3.14%	3.05%	2.54%	2.45%	2.52%	2.39%	2.37%	2.26%	2.40%	2.65%	2.55%	2.40%	2.39%	2.43%	2.38%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	10	30	52	76	99	122	147	174	203	235	266	296	314	323	329	333
New Commercial 1	0	3	7	16	35	57	78	100	123	148	170	194	219	243	269	295	322	348	375	402
Commercial R&R 1	0	6	11	16	21	27	32	38	42	48	53	59	63	69	75	80	86	90	96	101
New SF Res 1	0	1	4	8	15	24	33	41	50	60	68	77	86	96	105	114	123	131	141	150
New MF Res 1	0	0	0	0	1	1	4	4	5	5	6	6	8	9	10	10	11	11	13	14
New Manuf Housing 1	0	0	3	5	9	14	19	24	31	36	41	48	54	59	65	70	76	81	88	93
New Res Light 1	0	0	2	3	5	8	10	12	15	17	20	22	24	27	29	32	34	37	37	39
Wtr Htr Heat Pumps	0	0	1	3	7	12	16	22	28	34	41	46	53	59	66	72	78	84	90	96
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	3	10	18	25	32	39	46	54	61	67	71	71	71	71	71	71	71	71	71
Industrial 1	0	2	8	22	34	48	60	72	86	98	112	124	138	152	164	178	190	204	216	230
Irrigation 1	0	0	2	2	4	5	6	7	9	9	11	12	13	14	16	16	18	19	21	21
T&D Effic Impr	0	3	11	17	25	31	39	46	53	60	67	74	82	89	95	103	110	117	124	131
Industrial 2	0	2	6	14	24	32	40	50	58	68	76	86	94	104	112	122	132	140	150	158
Exist. Commercial 1	0	2	11	23	40	60	81	101	122	142	163	182	203	223	244	264	283	304	324	345
MF Res Weath	0	2	5	10	15	20	24	29	34	39	40	40	40	40	40	40	40	40	40	40
SF Res Weath	0	4	12	23	33	43	54	64	73	83	87	87	87	87	87	87	87	87	87	87
Ex. Res. Lighting-1	0	1	1	2	4	5	6	7	8	10	11	12	13	14	14	15	16	17	18	19
High Cost Block	0	0	0	0	0	0	0	0	0	0	2	8	17	25	35	48	61	76	89	104
Subtotal	192	221	286	424	549	691	835	1031	1182	1332	1474	1614	1760	1908	2055	2205	2344	2472	2601	2726
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	110	110	110	110	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Combined Cycle 1	0	0	0	0	0	0	0	714	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071	1071
Small Hydro 2	0	0	0	0	0	0	15	29	40	54	62	69	76	86	94	101	101	101	101	101
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	50	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	180	340	480	500	500	500	500	500	500	500	500	500	500	500	500
Cogen 2	0	0	0	0	0	0	0	49	57	57	57	57	57	57	57	57	57	57	57	57
WNP 1	0	0	0	0	0	0	0	0	0	0	818	818	818	818	818	818	818	818	818	818
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	714	714	1071	1071	1428	1428	1428
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	31	38
Cogen 3	0	0	0	0	0	0	0	0	328	712	896	1016	1016	1016	1072	1072	1072	1072	1128	1128
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	29	29
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	280	280	280	280	280	280	315	315
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	107	111	114
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	597	895	895	1194	1492	1790	1790	1790	1790	1790	1790
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	72	72	224	416	456	456	464	504
E. Wash Coal Gas	0	0	0	0	0	0	262	262	262	262	262	262	262	262	262	262	523	785	785	785
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	523	785
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16	64
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	50	81	146	428	1000	2037	3696	5080	6413	6560	6954	7637	8151	8707	9008	9635	10291	10656
Total Firm Resources	19493	19508	19574	19702	19844	20225	20906	22105	23728	25075	26499	26736	27162	27851	28482	29159	29616	30387	31195	31581
Load/Resource Balance	-462	-1169	-1674	-2150	-2648	-2898	-2849	-2195	-1108	-327	572	275	181	277	238	254	73	192	322	28

Study ID :8-APR-91 12:41:47
Study Title:High Gase Price Scenario - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2934	2915	2888	2881	2892	2907	2923	2936	2948	2958	2969	2982	2995	3012	3035	3058	3081	3103	3128	3155
Observed Rate	-0.63%	-0.95%	-0.24%	0.37%	0.51%	0.55%	0.47%	0.41%	0.34%	0.36%	0.45%	0.44%	0.57%	0.74%	0.76%	0.75%	0.71%	0.80%	0.87%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2108	-2104	-2122	-1903	-1918	-1937	-1946	-1854	-1876	-1895	-1889	-1889	-1909	-1936	-1949	-1851	-1809	-1826	-1846	-1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	11	16	22	27	33	40	47	53	58	64	67	68	69	69
New Commercial 1	0	0	0	1	1	3	4	5	6	8	9	11	12	13	15	16	18	20	21	23
Commercial R&R 1	0	1	3	4	6	7	9	10	11	13	14	16	17	19	20	22	23	24	26	27
New SF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	8	8	9
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3	3
New Manuf Housing 1	0	0	0	1	2	2	3	4	6	7	8	9	10	11	12	13	14	15	17	18
New Res Light 1	0	0	0	0	1	1	1	2	2	2	3	3	3	4	4	5	5	5	6	6
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	1	2	2	3	3	4	4	5	5	6	6	7	7
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	35	35	35	35	35	35	35	35	35	35
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	70	70	70	70	70	70	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	44	44	44	44	44	44	44	44	44	44
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	48	48	48	48	48	48	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	68	68	68	68	68	68	68	68	68	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12	12	12	12	12	12	12	12	12	12	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61	61	61	61	61	61	61	61	61	61	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	14	44	86	135	188	245	297	352	407	419	431	444	455	466	477	486	492	501	506
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5336	5372	5373	5623	5702	5782	5958	6235	6223	6214	6226	6234	6156	6070	6076	6192	6249	6244	6236	6346
Load/Resource Balance	420	676	906	1364	1635	1901	2062	2326	2303	2407	2531	2649	2681	2578	2562	2655	2688	2662	2629	2712

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Study Title:High Gase Price Scenario - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	8920	8853	8823	8795	8785	8785	8795	8797	8791	8779	8771	8772	8776	8796	8831	8867	8901	8934	8973	9019
Observed Rate	-0.75%	-0.35%	-0.32%	-0.11%	0.01%	0.11%	0.02%	-0.07%	-0.14%	-0.09%	0.02%	0.05%	0.23%	0.39%	0.41%	0.38%	0.37%	0.44%	0.51%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	5	16	28	41	54	67	82	97	113	128	142	157	165	168	169	169
New Commercial 1	0	0	1	3	8	16	23	32	40	48	57	66	76	85	95	105	114	125	135	146
Commercial R&R 1	0	3	6	9	11	14	17	20	23	26	28	31	34	37	40	43	45	48	51	54
New SF Res 1	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New MF Res 1	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8
New Manuf Housing 1	0	0	1	2	4	6	9	12	15	17	20	23	26	29	32	35	38	41	44	47
New Res Light 1	0	0	0	0	1	1	2	2	3	3	4	4	5	6	6	7	7	8	8	9
Wtr Htr Heat Pumps	0	0	0	1	1	2	3	4	5	6	7	8	10	11	12	13	14	15	17	18
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	50	50	50	53	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	72	76	84	93	103	112	118
Irrigation 1	0	0	1	2	3	4	5	6	7	8	8	8	8	8	9	10	11	12	13	14
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	41	41	41	44	48	53	58	63	68	72
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	49	52	57	64	70	77	81
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	134	134	134	134	134	137	144	156	172	192
MF Res Weath	0	2	6	11	17	22	27	32	38	43	43	43	43	43	43	43	43	43	43	43
SF Res Weath	0	2	8	15	22	29	36	43	50	57	57	57	57	57	57	57	57	57	57	57
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	13	13	13	13	13	13	13	13
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	18	61	122	195	282	372	460	552	640	673	705	742	784	835	891	945	1002	1061	1116
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	19	29
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	29	44	64
Total Firm Resources	9519	9549	9590	9410	9410	9423	9346	9271	9241	9212	9193	9176	9185	9170	9179	9079	9093	9173	9267	9103
Load/Resource Balance	599	696	767	615	626	638	551	474	450	433	423	404	409	374	348	212	192	239	293	83

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Study Title:High Gase Price Scenario - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4445	4398	4384	4371	4369	4372	4380	4384	4386	4384	4383	4386	4391	4403	4424	4445	4463	4481	4502	4526
Observed Rate	-1.05%	-0.33%	-0.30%	-0.05%	0.07%	0.19%	0.09%	0.04%	-0.04%	-0.04%	0.07%	0.11%	0.29%	0.46%	0.47%	0.41%	0.40%	0.47%	0.55%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2001	1966	1934	1903	1918	1937	1946	1854	1876	1895	1889	1889	1909	1936	1949	1851	1809	1826	1846	1736
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	6	10	15	20	25	30	37	43	48	54	59	62	63	64	64
New Commercial 1	0	0	0	1	2	4	6	9	11	13	15	18	20	22	25	27	30	33	35	38
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	0	1	1	2	2	3	3	3	4	4	5	5	6	6	7	7	8
New MF Res 1	0	0	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	3
New Manuf Housing 1	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	1	1	2	2	3	3	3	4	4	5	5	6	6	7
Subtotal	0	0	0	2	6	14	22	32	42	50	59	71	80	91	101	111	118	125	129	136
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4445	4399	4385	4373	4376	4387	4403	4318	4328	4334	4343	4357	4371	4393	4422	4459	4487	4510	4535	4570
Load/Resource Balance	0	0	1	2	7	15	23	-66	-58	-50	-40	-29	-19	-11	-1	14	24	29	33	44

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Study Title:High Gase Price Scenario - LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16299	16167	16094	16047	16045	16064	16098	16118	16125	16121	16122	16140	16162	16212	16290	16370	16445	16518	16603	16701
Observed Rate	-0.81%	-0.45%	-0.30%	-0.01%	0.12%	0.21%	0.12%	0.05%	-0.03%	0.01%	0.11%	0.14%	0.31%	0.48%	0.49%	0.46%	0.44%	0.51%	0.59%	
DSI Firm Load	1982	1781	1579	1378	1176	974	973	972	971	848	725	602	479	479	479	479	479	479	479	479
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	9	29	49	72	96	119	145	174	203	229	254	280	294	299	302	302
New Commercial 1	0	0	1	5	11	23	33	46	57	69	81	95	108	120	135	148	162	178	191	207
Commercial R&R 1	0	4	9	13	17	21	26	30	34	39	42	47	51	56	60	65	68	72	77	81
New SF Res 1	0	0	0	1	3	4	7	8	11	12	14	16	18	20	22	24	26	29	30	33
New MF Res 1	0	0	0	0	1	1	3	4	5	5	6	6	8	9	10	10	11	11	13	14
New Manuf Housing 1	0	0	1	4	7	10	15	20	26	30	35	40	45	50	55	60	65	70	76	81
New Res Light 1	0	0	0	0	2	2	3	4	5	5	7	7	8	10	10	12	12	13	14	15
Wtr Htr Heat Pumps	0	0	0	1	1	4	5	6	9	10	13	14	17	19	21	23	25	27	30	32
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	85	85	85	88	94	94	94	94	94	94
Industrial 1	0	4	12	30	48	66	86	104	122	140	140	140	140	142	146	154	163	173	182	188
Irrigation 1	0	0	2	4	5	7	9	11	12	14	14	14	14	14	15	16	17	18	19	20
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	85	85	85	88	92	97	102	107	112	116
Industrial 2	0	2	8	20	32	46	58	70	82	96	96	96	96	97	100	105	112	118	125	129
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	202	202	202	202	202	205	212	224	240	260
MF Res Weath	0	3	8	14	22	28	35	41	48	55	55	55	55	55	55	55	55	55	55	55
SF Res Weath	0	5	17	31	46	60	75	89	104	118	118	118	118	118	118	118	118	118	118	118
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	13	13	13	13	13	13	13	13
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	32	105	210	336	484	639	789	946	1097	1151	1207	1266	1330	1402	1479	1549	1619	1691	1758
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	25	35
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	19	29
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	29	44	64
Total Firm Resources	19300	19320	19347	19406	19488	19592	19707	19825	19792	19760	19762	19767	19712	19633	19678	19730	19828	19926	20038	20019
Load/Resource Balance	1019	1372	1674	1982	2267	2554	2636	2735	2696	2791	2914	3024	3071	2941	2909	2881	2904	2930	2956	2839

Study ID :5-APR-91 13:43:07
Study Title:High Gase Price Scenario - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	2983	2993	2988	3004	3036	3072	3111	3147	3182	3216	3249	3284	3320	3362	3412	3464	3514	3565	3616	3670
Observed Rate	0.32%	-0.18%	0.55%	1.08%	1.18%	1.27%	1.16%	1.10%	1.07%	1.02%	1.08%	1.10%	1.26%	1.49%	1.51%	1.45%	1.43%	1.45%	1.49%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2191	-2243	-2303	-2128	-2178	-2233	-2278	-2202	-2258	-2313	-2343	-2376	-2429	-2492	-2545	-2488	-2489	-2550	-2612	-2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	13	19	25	31	38	46	54	61	68	75	79	81	82	83
New Commercial 1	0	0	0	1	2	4	6	7	9	11	13	15	16	18	20	22	24	27	29	31
Commercial R&R 1	0	2	4	6	8	10	12	14	16	18	20	22	24	26	28	30	32	34	36	38
New SF Res 1	0	0	1	1	2	3	4	5	6	7	8	9	11	12	13	14	15	16	18	19
New MF Res 1	0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	1	2	4	5	7	9	10	12	14	16	17	19	21	22	24	26	27
New Res Light 1	0	0	0	1	1	2	2	3	4	5	5	6	7	7	8	9	10	10	11	12
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	3	4	4	5	6	7	8	9	10	11	12	13	14
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	35	35	35	35	35	35	35	35	35	35
Industrial 1	0	2	6	15	24	33	43	52	61	70	70	70	70	70	70	70	70	70	70	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	44	44	44	44	44	44	44	44	44	44
Industrial 2	0	1	4	10	16	23	29	35	41	48	48	48	48	48	48	48	48	48	48	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	68	68	68	68	68	68	68	68	68	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12	12	12	12	12	12	12	12	12	12	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61	61	61	61	61	61	61	61	61	61	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	47	90	139	197	258	315	373	431	544	659	773	787	803	820	832	843	854	863
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	5252	5234	5194	5401	5448	5496	5638	5904	5861	5821	5899	5974	5965	5847	5818	5897	5915	5869	5823	5895
Load/Resource Balance	163	269	367	693	840	986	1090	1320	1243	1169	1214	1254	1209	1051	972	1000	967	871	774	792

Study ID :5-APR-91 13:43:07
Study Title:High Gase Price Scenario - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9075	9108	9161	9219	9283	9356	9441	9513	9582	9648	9713	9786	9863	9962	10084	10210	10333	10459	10583	10715
Observed Rate	0.37%	0.58%	0.64%	0.70%	0.78%	0.91%	0.77%	0.72%	0.69%	0.68%	0.75%	0.78%	1.00%	1.22%	1.25%	1.21%	1.22%	1.19%	1.24%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	18	32	47	62	78	94	112	130	148	166	183	194	198	201	203
New Commercial 1	0	1	2	6	13	24	34	45	56	68	79	91	104	116	129	142	155	168	182	197
Commercial R&R 1	0	4	8	12	16	20	23	27	31	35	39	43	47	51	55	59	63	66	70	74
New SF Res 1	0	0	1	2	3	5	7	9	11	13	15	17	19	22	24	26	28	30	32	35
New MF Res 1	0	0	0	1	1	1	2	3	3	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	3	6	10	14	18	23	28	32	37	42	46	51	55	60	64	68	73
New Res Light 1	0	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Wtr Htr Heat Pumps	0	0	1	2	3	4	6	8	10	12	14	16	19	21	23	25	27	29	31	34
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	143	147	148
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	92	95	95	95
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	14	14	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	21	67	133	213	309	407	505	606	709	799	886	976	1060	1147	1233	1312	1377	1436	1495
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	5	19	33	43	52	62	71	76	76	76	76	76	76	76
Small Hydro 2	0	0	0	0	0	0	7	18	29	40	47	54	62	69	76	83	87	87	87	87
Thermal Eff Imp	0	0	0	0	0	0	0	44	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	120	240	240	260	320	360	420	420	420	420	420	420
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	8	8	15	15	15	15	15	23	23
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	5	15	37	116	267	408	424	469	546	605	672	679	1040	1040	1048	1405
Total Firm Resources	9519	9551	9595	9420	9432	9463	9418	9432	9565	9687	9746	9827	9965	10055	10164	10098	10484	10561	10649	10823
Load/Resource Balance	444	443	434	201	149	108	-23	-81	-17	39	32	41	102	93	81	-112	151	103	65	108

Study ID :5-APR-91 13:43:07
Study Title:High Gase Price Scenario - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4529	4537	4565	4596	4630	4668	4712	4751	4788	4824	4860	4899	4938	4989	5051	5115	5179	5243	5308	5376
Observed Rate	0.18%	0.61%	0.67%	0.74%	0.82%	0.95%	0.82%	0.79%	0.75%	0.74%	0.80%	0.80%	1.02%	1.25%	1.27%	1.24%	1.25%	1.23%	1.28%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2084	2105	2115	2128	2178	2233	2278	2202	2258	2313	2343	2376	2429	2492	2545	2488	2489	2550	2612	2543
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	12	17	23	29	35	42	49	56	63	69	73	75	76	76
New Commercial 1	0	0	1	2	4	7	9	12	15	18	21	24	27	31	34	37	41	44	48	52
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	0	1	2	3	3	5	6	7	8	9	10	11	12	13	14	15	16	17
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	1	2	3	5	6	8	10	11	13	14	16	18	19	21	22	24	25
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	0	1	2	2	3	4	5	6	7	8	8	9	10	11	12	13
Subtotal	0	0	2	4	10	21	32	43	56	69	81	96	109	124	137	149	162	170	179	186
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4529	4538	4567	4600	4640	4689	4744	4679	4725	4771	4818	4869	4920	4981	5054	5135	5209	5279	5349	5428
Load/Resource Balance	0	1	2	4	11	21	32	-72	-63	-53	-42	-29	-18	-8	3	20	31	36	41	52

Study ID :5-APR-91 13:43:07
Study Title:High Gase Price Scenario - MEDIUM LOW LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16587	16638	16713	16819	16949	17096	17264	17412	17552	17688	17822	17969	18121	18312	18547	18789	19026	19267	19508	19760
Observed Rate	0.31%	0.45%	0.63%	0.78%	0.87%	0.98%	0.85%	0.81%	0.77%	0.76%	0.83%	0.85%	1.05%	1.28%	1.31%	1.26%	1.27%	1.25%	1.30%	
DSI Firm Load	2106	1973	1839	1705	1571	1437	1437	1436	1436	1436	1435	1435	1435	1434	1434	1434	1433	1433	1433	1433
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	10	32	57	83	110	138	167	200	233	265	297	327	346	354	359	362
New Commercial 1	0	1	3	9	19	35	49	64	80	97	113	130	147	165	183	201	220	239	259	280
Commercial R&R 1	0	6	12	18	24	30	35	41	47	53	59	65	71	77	83	89	95	100	106	112
New SF Res 1	0	0	2	4	7	11	14	19	23	27	31	35	40	45	49	53	57	61	66	71
New MF Res 1	0	0	0	1	1	1	4	5	5	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	5	10	17	24	31	40	48	55	64	72	79	88	95	103	110	118	125
New Res Light 1	0	0	0	2	3	5	6	8	10	12	13	15	17	18	20	22	24	25	27	29
Wtr Htr Heat Pumps	0	0	1	2	3	6	10	13	17	20	24	28	33	37	40	44	48	52	56	61
BPA Contract Recall	0	0	0	0	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	91	94	94	94	94	94	94	94	94	94
Industrial 1	0	4	12	30	48	66	86	104	122	140	149	158	168	177	186	196	205	213	217	218
Irrigation 1	0	0	2	4	5	7	9	11	12	14	15	16	17	18	19	20	21	22	23	24
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	90	95	100	104	109	114	119	124	128	133
Industrial 2	0	2	8	20	32	46	58	70	82	96	102	108	115	121	128	134	140	143	143	143
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	221	240	259	278	297	317	336	355	374	393
MF Res Weath	0	3	8	14	22	28	35	41	48	55	56	56	56	56	56	56	56	56	56	56
SF Res Weath	0	5	17	31	46	60	75	89	104	118	120	120	120	120	120	120	120	120	120	120
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	13	13	14	14	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	36	116	227	362	527	697	863	1035	1209	1424	1641	1858	1971	2087	2202	2306	2390	2469	2544
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	5	19	33	43	52	62	71	76	76	76	76	76	76	76
Small Hydro 2	0	0	0	0	0	0	7	18	29	40	47	54	62	69	76	83	87	87	87	87
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermal Eff Imp	0	0	0	0	0	0	0	44	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	0	0	0	120	240	240	260	320	360	420	420	420	420	420	420
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	8	8	15	15	15	15	15	23	23
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	357
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	5	15	37	116	267	408	424	469	546	605	672	679	1040	1040	1048	1405
Total Firm Resources	19301	19323	19355	19421	19520	19648	19800	20015	20151	20278	20462	20670	20849	20883	21036	21130	21608	21709	21821	22146
Load/Resource Balance	607	713	803	898	1000	1115	1100	1167	1163	1154	1204	1266	1293	1136	1056	908	1149	1009	880	953

Study ID :8-APR-91 12:41:01
Study Title:High Gase Price Scenario - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3028	3063	3082	3117	3160	3207	3261	3313	3365	3415	3464	3514	3566	3623	3689	3759	3829	3899	3969	4041
Observed Rate	1.16%	0.63%	1.12%	1.39%	1.51%	1.68%	1.60%	1.56%	1.48%	1.42%	1.46%	1.46%	1.62%	1.82%	1.88%	1.87%	1.83%	1.80%	1.80%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2273	-2384	-2489	-2347	-2426	-2510	-2584	-2522	-2606	-2687	-2740	-2795	-2874	-2964	-3043	-3015	-3045	-3135	-3223	-3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	8	14	20	26	33	40	48	56	64	71	79	84	86	87	88
New Commercial 1	0	0	1	1	3	5	7	10	12	14	16	19	21	24	27	29	32	34	37	40
Commercial R&R 1	0	2	5	7	10	12	15	17	19	22	24	27	29	32	34	36	39	41	44	46
New SF Res 1	0	0	1	1	3	4	5	7	8	10	11	13	14	16	17	19	20	22	23	25
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	8	10	12	13	15	17	19	21	23	24	26	28	30
New Res Light 1	0	0	0	1	2	2	3	4	5	6	6	7	8	9	10	11	11	12	13	14
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	6	7	8	9	10	11	12	14	15	16	17
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	152	155
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	104	107
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	1	2	4	5	6	8	9	10	11
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	15	49	92	147	203	363	521	676	740	794	846	897	949	999	1051	1099	1142	1184	1219
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	0	0	0	0	0	15	30	45	45	60	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	0	0	0	0	0	0	0	5	10	14	14	14	14	14
Small Hydro 2	0	0	0	0	0	0	0	0	0	7	11	11	11	14	18	18	18	18	18	18
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	868	868	868
Thermal Eff Imp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	15	37	56	56	71	94	103	107	107	975	975	975
Total Firm Resources	5171	5094	5009	5185	5205	5225	5438	5788	5833	5791	5808	5800	5717	5631	5619	5709	5732	6561	6520	6591
Load/Resource Balance	-41	-123	-196	-25	-18	-15	175	473	466	374	343	284	150	6	-72	-52	-99	660	549	548

Study ID :8-APR-91 12:41:01
Study Title:High Gase Price Scenario - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9222	9357	9496	9618	9731	9856	9995	10127	10253	10372	10488	10609	10738	10891	11067	11253	11438	11624	11806	11990
Observed Rate	1.46%	1.49%	1.28%	1.18%	1.28%	1.41%	1.32%	1.25%	1.16%	1.12%	1.16%	1.22%	1.42%	1.61%	1.68%	1.64%	1.63%	1.56%	1.56%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	6	19	34	50	66	82	99	117	136	155	174	193	206	210	214	215
New Commercial 1	0	1	4	8	17	31	44	58	73	88	103	119	135	151	168	184	201	218	236	254
Commercial R&R 1	0	5	10	14	19	24	29	34	38	43	48	53	57	62	67	72	77	81	86	91
New SF Res 1	0	0	1	2	4	7	9	12	15	17	20	23	26	29	32	35	37	40	43	46
New MF Res 1	0	0	0	1	1	2	2	3	4	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	4	7	12	16	21	26	31	36	41	45	50	55	60	65	70	74	79
New Res Light 1	0	0	1	1	2	3	4	6	7	8	9	10	12	13	14	15	16	18	19	20
Wtr Htr Heat Pumps	0	0	1	2	4	6	8	10	13	15	18	21	23	26	29	31	34	36	39	42
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	152	155
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	104	107
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96
Subtotal	0	22	72	138	223	328	431	537	646	752	852	950	1052	1156	1262	1368	1468	1557	1645	1724
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	52	62	71	76	76	76	76	76	76	76
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	43	43	43	51	58	65	72	80	83	83
Thermal Eff Imp	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	80	240	240	380	380	380	380	400	420	420	420	420	420	420	420
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	6	17	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	35	105	105	175	245	280	280
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	15	26	33	37	52	59	70	81	92
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298	298	298	298	597
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	24
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	155	350	733	898	1282	1282	1307	1353	1446	1539	1859	1943	2040	2097	2430
Total Firm Resources	9519	9553	9599	9432	9454	9622	9756	10080	10233	10606	10656	10727	10851	10993	11147	11413	11544	11741	11906	12080
Load/Resource Balance	297	196	102	-186	-277	-234	-239	-47	-21	234	168	118	112	101	80	161	106	117	100	91

Study ID :8-APR-91 12:41:01
Study Title:High Gase Price Scenario - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4611	4678	4751	4815	4877	4945	5018	5088	5155	5218	5277	5340	5406	5485	5575	5670	5764	5859	5951	6045
Observed Rate	1.46%	1.55%	1.35%	1.29%	1.39%	1.48%	1.39%	1.31%	1.22%	1.14%	1.18%	1.24%	1.45%	1.64%	1.71%	1.66%	1.64%	1.58%	1.58%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2166	2246	2301	2347	2426	2510	2584	2522	2606	2687	2740	2795	2874	2964	3043	3015	3045	3135	3223	3179
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	2	7	13	18	24	30	37	44	52	59	66	73	77	79	80	81
New Commercial 1	0	0	1	2	5	9	12	16	20	24	27	31	36	40	44	49	53	57	62	67
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	1	2	4	5	6	8	9	10	12	13	15	16	17	19	20	22	23
New MF Res 1	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	7	9	11	12	14	16	17	19	21	23	24	26	27
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	1	2	3	4	5	6	7	8	9	10	11	13	14	15	16
Subtotal	0	0	3	5	13	25	39	51	66	80	93	110	127	142	157	173	188	197	208	217
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4611	4679	4754	4821	4890	4970	5056	5007	5083	5156	5228	5303	5381	5471	5573	5685	5791	5891	5989	6095
Load/Resource Balance	0	1	3	6	13	25	38	-81	-72	-62	-49	-36	-25	-14	-2	15	26	32	38	50

Study ID :8-APR-91 12:41:01
Study Title:High Gase Price Scenario - MEDIUM LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	16861	17098	17329	17550	17768	18008	18274	18529	18773	19005	19229	19463	19710	19999	20332	20682	21031	21382	21726	22076
Observed Rate	1.41%	1.35%	1.27%	1.25%	1.35%	1.48%	1.39%	1.32%	1.23%	1.18%	1.22%	1.27%	1.47%	1.66%	1.72%	1.69%	1.67%	1.61%	1.61%	
DSI Firm Load	2184	2154	2123	2093	2063	2032	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002	2002
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	11	34	61	88	116	145	176	209	244	278	311	345	367	375	381	384
New Commercial 1	0	1	6	11	25	45	63	84	105	126	146	169	192	215	239	262	286	309	335	361
Commercial R&R 1	0	7	15	21	29	36	44	51	57	65	72	80	86	94	101	108	116	122	130	137
New SF Res 1	0	0	3	4	9	15	19	25	31	36	41	48	53	60	65	71	76	82	88	94
New MF Res 1	0	0	0	1	1	3	4	5	6	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	8	13	20	28	36	45	54	61	70	78	86	95	104	112	120	128	136
New Res Light 1	0	0	1	2	4	5	7	10	12	14	15	17	20	22	24	26	27	30	32	34
Wtr Htr Heat Pumps	0	0	1	2	6	8	12	16	21	26	31	36	40	45	50	54	61	65	70	75
BPA Contract Recall	0	0	0	0	0	0	97	195	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	304	310
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	208	214
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	16	17	19	20	21	23	24	25	26
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96
Subtotal	0	37	124	235	383	556	833	1109	1388	1572	1739	1906	2076	2247	2418	2592	2755	2896	3037	3160
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	5	15	25	35	35	50	65	80	80	95	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	52	62	71	81	86	90	90	90	90	90
Small Hydro 2	0	0	0	0	0	0	11	22	33	50	54	54	54	65	76	83	90	98	101	101
WNP 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	868	868	868
Thermal Eff Imp	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	0	80	240	240	380	380	380	380	400	420	420	420	420	420	420	420
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	6	17	29	29	29	29	29	29
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	35	105	105	175	245	280	280
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	15	26	33	37	52	59	70	81	92
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	298	298	298	298	597
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	24
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	5	15	155	350	733	913	1319	1338	1363	1424	1540	1642	1966	2050	3015	3072	3405
Total Firm Resources	19301	19326	19362	19437	19549	19817	20250	20875	21149	21553	21692	21831	21949	22095	22339	22807	23067	24192	24415	24767
Load/Resource Balance	256	74	-91	-205	-282	-223	-26	345	374	546	462	366	237	94	6	124	34	809	687	688

Study ID :5-APR-91 13:42:37
Study Title:High Gase Price Scenario - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	3080	3141	3175	3229	3298	3370	3443	3514	3582	3647	3715	3787	3858	3935	4020	4107	4191	4276	4367	4456
Observed Rate	1.98%	1.09%	1.68%	2.14%	2.18%	2.18%	2.05%	1.93%	1.83%	1.85%	1.95%	1.87%	2.00%	2.15%	2.17%	2.04%	2.03%	2.12%	2.04%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-2367	-2536	-2673	-2571	-2693	-2817	-2927	-2880	-2999	-3113	-3192	-3278	-3389	-3511	-3621	-3622	-3675	-3790	-3912	-3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	9	15	21	28	34	42	50	59	67	75	83	89	91	92	93
New Commercial 1	0	0	1	2	4	7	9	12	15	18	21	24	27	30	34	37	40	44	47	51
Commercial R&R 1	0	3	5	8	11	13	16	19	22	24	27	30	32	35	38	40	43	46	49	51
New SF Res 1	0	0	1	2	4	5	7	9	11	13	15	17	19	21	24	26	28	30	32	34
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	26	28	30	32
New Res Light 1	0	0	0	1	2	3	4	5	5	6	7	8	9	10	11	12	13	14	15	16
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	6	7	8	10	11	13	14	16	17	18	20	21
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35	39	41	41	41	41	41	41	41	41	41
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	2	3	4	5	5	6	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44	49	54	59	64	70	75	80	85	90	96
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68	78	87	97	106	116	126	135	145	155	164
MF Res Weath	0	1	2	3	5	6	8	9	10	12	13	13	13	13	13	13	13	13	13	13
SF Res Weath	0	3	9	16	24	31	39	46	54	61	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	64	144	241	337	392	453	517	627	689	751	811	863	916	967	1021	1074	1123	1168	1215	1259
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	15	30	45	45	60	60	60	60	60	75	75	75	75	75	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	5	5	5	5	5	5	5	10	10	10	10	10	10
Small Hydro 2	0	0	0	0	0	0	4	4	4	7	7	7	7	11	11	11	11	11	11	11
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	818	818	818	818	818
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	6	21	36	51	60	75	943	946	946	946	961	965	970	1788	1788	1788	1788	1788
Total Firm Resources	5141	5070	5024	5227	5220	5217	5308	5613	6380	6288	6262	6225	6111	5976	5930	6806	6807	6743	6673	6726
Load/Resource Balance	-221	-301	-388	-246	-306	-365	-347	-112	588	430	351	254	84	-129	-259	529	446	297	136	101

Study ID :5-APR-91 13:42:37
Study Title:High Gase Price Scenario - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9398	9637	9839	10036	10240	10450	10660	10858	11048	11228	11400	11587	11780	11997	12234	12478	12706	12940	13187	13427
Observed Rate	2.54%	2.09%	2.00%	2.04%	2.04%	2.01%	1.86%	1.75%	1.63%	1.53%	1.63%	1.67%	1.84%	1.98%	1.99%	1.83%	1.84%	1.91%	1.82%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	7	21	36	53	69	86	104	123	142	163	184	204	217	222	226	228
New Commercial 1	0	2	5	11	23	40	57	75	93	112	131	151	171	192	214	234	256	278	300	324
Commercial R&R 1	0	5	11	16	21	27	32	37	43	48	53	59	64	69	75	80	85	91	96	101
New SF Res 1	0	0	2	3	6	9	13	16	20	24	27	31	35	39	43	47	51	54	58	62
New MF Res 1	0	0	0	1	1	2	2	3	3	4	5	5	6	7	7	8	9	9	10	10
New Manuf Housing 1	0	1	2	5	8	13	17	22	27	33	38	43	49	54	59	65	70	75	80	85
New Res Light 1	0	0	1	1	3	4	5	7	8	9	11	12	14	15	17	18	19	21	22	23
Wtr Htr Heat Pumps	0	0	1	3	5	7	10	13	16	19	23	26	29	33	36	39	43	46	49	52
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96
Subtotal	0	23	75	146	237	347	457	569	683	799	906	1011	1122	1235	1351	1465	1573	1671	1769	1865
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	52	62	71	76	76	76	76	76	76	76
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	43	51	58	65	72	80	87	87	87	87
Thermal Eff Imp	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	280	400	400	400	420	420	420	420	420	420	420	420	420
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	140	140	175	175	175	245	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	15	26	33	37	37	52	63	74	85	96	107	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	298	298	597	895	895	1194	1492
E. Wash Coal Gas	0	0	0	0	0	0	523	523	523	523	523	523	523	523	523	523	523	523	523	523
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	60	110	357	1091	1474	1665	2056	2060	2168	2234	2562	2580	2898	3214	3233	3532	3837
Total Firm Resources	9519	9554	9601	9493	9561	9843	10524	10854	11039	11427	11488	11649	11802	12188	12278	12548	12919	13046	13462	13627
Load/Resource Balance	121	-83	-237	-542	-679	-606	-136	-4	-9	199	87	63	21	191	43	70	213	106	275	200

Study ID :5-APR-91 13:42:37
Study Title:High Gase Price Scenario - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4705	4830	4935	5038	5144	5252	5361	5464	5568	5667	5754	5849	5949	6061	6183	6309	6427	6548	6676	6801
Observed Rate	2.67%	2.18%	2.09%	2.10%	2.11%	2.07%	1.92%	1.89%	1.78%	1.54%	1.64%	1.71%	1.88%	2.02%	2.04%	1.87%	1.88%	1.96%	1.86%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2260	2398	2485	2571	2693	2817	2927	2880	2999	3113	3192	3278	3389	3511	3621	3622	3675	3790	3912	3897
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	8	14	20	26	32	39	47	54	62	69	77	82	84	85	85
New Commercial 1	0	0	1	3	7	11	16	20	25	30	35	40	45	51	56	62	67	73	79	85
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	2	3	5	7	8	10	12	14	16	18	20	22	24	25	27	29	31
New MF Res 1	0	0	0	0	0	1	1	1	1	1	1	2	2	2	2	2	3	3	3	3
New Manuf Housing 1	0	0	1	2	3	4	6	8	10	11	13	15	17	19	21	22	24	26	28	29
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	3	4	5	6	8	9	10	12	13	14	16	17	18	20
Subtotal	0	0	3	7	17	31	47	61	77	92	110	129	146	166	183	201	217	230	242	253
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4705	4831	4938	5045	5160	5283	5407	5374	5487	5596	5696	5804	5917	6041	6176	6320	6451	6578	6712	6849
Load/Resource Balance	0	1	3	7	16	31	45	-91	-81	-71	-58	-44	-32	-20	-7	11	24	30	36	49

Study ID :5-APR-91 13:42:37
Study Title:High Gase Price Scenario - MEDIUM HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17183	17608	17949	18303	18682	19072	19464	19837	20197	20542	20869	21222	21587	21993	22438	22895	23325	23764	24230	24683
Observed Rate	2.47%	1.94%	1.97%	2.07%	2.09%	2.06%	1.91%	1.82%	1.71%	1.59%	1.69%	1.72%	1.88%	2.02%	2.04%	1.88%	1.89%	1.96%	1.87%	
DSI Firm Load	2282	2230	2237	2244	2228	2212	2211	2211	2211	2210	2197	2183	2170	2170	2170	2170	2170	2170	2170	2170
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	13	38	65	94	123	152	185	220	255	292	328	364	388	397	403	406
New Commercial 1	0	2	7	16	34	58	82	107	133	160	187	215	243	273	304	333	363	395	426	460
Commercial R&R 1	0	8	16	24	32	40	48	56	65	72	80	89	96	104	113	120	128	137	145	152
New SF Res 1	0	0	4	7	13	19	27	33	41	49	56	64	72	80	89	97	104	111	119	127
New MF Res 1	0	0	0	1	1	4	4	5	5	6	8	9	10	11	11	13	15	15	16	16
New Manuf Housing 1	0	1	4	9	14	22	30	38	47	56	65	74	84	93	102	111	120	129	138	146
New Res Light 1	0	0	1	2	5	7	9	12	13	15	18	20	23	25	28	30	32	35	37	39
Wtr Htr Heat Pumps	0	0	1	3	7	11	16	21	27	32	39	45	50	58	63	69	76	81	87	93
BPA Contract Recall	64	128	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	308	326
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	212	224
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96
Subtotal	64	167	319	490	646	831	1021	1257	1449	1642	1827	2003	2184	2368	2555	2740	2913	3069	3226	3377
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	80	95	95	95	95	95	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	34	48	57	57	67	76	81	86	86	86	86	86	86
Small Hydro 2	0	0	0	0	0	0	15	26	37	50	50	58	65	76	83	91	98	98	98	98
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	6	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	160	280	280	400	400	400	420	420	420	420	420	420	420	420	420
WNP 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	818	818	818	818	818
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	140	140	175	175	175	245	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	15	26	33	37	37	52	63	74	85	96	107	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	298	298	597	895	895	1194	1492
E. Wash Coal Gas	0	0	0	0	0	0	523	523	523	523	523	523	523	523	523	523	523	523	523	523
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	6	81	146	408	1151	1549	2608	3002	3006	3114	3195	3527	3550	4686	5002	5021	5320	5625
Total Firm Resources	19365	19455	19564	19765	19942	20343	21238	21841	22906	23310	23446	23678	23830	24205	24384	25674	26177	26368	26847	27203
Load/Resource Balance	-100	-383	-622	-781	-969	-940	-437	-207	498	558	380	273	73	42	-223	610	683	434	447	350

Study ID :8-APR-91 12:40:15
Study Title:High Gase Price Scenario - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = BPA

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00
Observed Load	3151	3260	3326	3414	3523	3631	3745	3846	3943	4045
Observed Rate	3.47%	2.02%	2.66%	3.17%	3.07%	3.15%	2.69%	2.53%	2.59%	2.55%
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352
Existing Resources	7444	7462	7450	7438	7484	7530	7661	7792	7747	7703
BPA Requirements	-2489	-2749	-2944	-2905	-3101	-3295	-3471	-3441	-3607	-3781
CONSERVATION PROGRAMS:										
Water Heat 1	0	0	0	0	3	10	17	24	32	39
New Commercial 1	0	0	1	3	6	9	13	16	20	24
Commercial R&R 1	0	3	5	8	10	13	15	18	20	23
New SF Res 1	0	1	2	3	6	9	13	16	19	23
New MF Res 1	0	0	0	0	0	1	1	1	1	2
New Manuf Housing 1	0	0	1	2	3	4	6	8	9	11
New Res Light 1	0	0	1	1	2	4	5	7	8	9
Wtr Htr Heat Pumps	0	0	0	0	1	3	4	6	8	10
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292
Cons. Volt. Reg.	0	2	6	10	14	18	23	27	31	35
Industrial 1	0	2	6	15	24	33	43	52	61	70
Irrigation 1	0	0	1	2	2	3	4	5	5	6
T&D Effic Impr	0	3	8	13	18	23	28	34	39	44
Industrial 2	0	1	4	10	16	23	29	35	41	48
Exist. Commercial 1	0	1	5	11	19	29	39	48	58	68
MF Res Weath	0	1	2	3	5	6	8	9	10	12
SF Res Weath	0	3	9	16	24	31	39	46	54	61
Ex. Res. Lighting-1	0	0	0	0	0	0	0	0	0	0
High Cost Block	0	0	0	0	0	0	0	0	0	0
Subtotal	192	209	243	339	395	461	529	644	708	777
GENERATING RESOURCES:										
Hydro Eff Imp	0	0	0	15	30	45	60	75	75	75
Small Hydro 1	0	0	0	0	0	0	5	10	14	14
Small Hydro 2	0	0	0	0	0	0	4	7	11	11
WNP 3	0	0	0	0	0	0	0	0	868	868
Thermal Eff Imp	0	0	6	6	6	6	6	6	6	6
Cogen 1	0	0	0	0	0	20	60	80	80	80
WNP 1	0	0	0	0	0	0	0	0	0	818
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	0
Combined Cycle 1	0	0	0	0	0	0	0	0	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	0
Wind 1	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Small Hydro 3	0	0	0	0	0	0	0	0	0	0
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	6	21	36	71	135	178	1411	2229
Total Firm Resources	5147	4921	4754	4895	4816	4768	4851	5171	6261	6928
Load/Resource Balance	-340	-653	-907	-876	-1062	-1217	-1248	-1028	-35	530

Operating Year	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4148	4254	4357	4468	4594	4718	4835	4955	5080	5206
Observed Rate	2.54%	2.43%	2.55%	2.80%	2.71%	2.48%	2.47%	2.52%	2.48%	
DSI Firm Load	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	7698	7692	7623	7553	7560	7566	7572	7577	7583	7577
BPA Requirements	-3921	-4064	-4222	-4392	-4561	-4616	-4728	-4903	-5085	-5134
CONSERVATION PROGRAMS:										
Water Heat 1	47	57	66	76	86	96	102	104	106	108
New Commercial 1	27	31	35	38	42	46	50	54	58	63
Commercial R&R 1	25	28	30	33	36	38	41	43	46	48
New SF Res 1	26	29	33	36	40	43	46	50	53	57
New MF Res 1	2	2	2	2	3	3	3	3	4	4
New Manuf Housing 1	13	15	16	18	20	22	23	25	27	29
New Res Light 1	11	12	13	15	16	18	19	20	22	23
Wtr Htr Heat Pumps	12	14	17	19	21	23	25	27	29	31
BPA Contract Recall	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	39	41	41	41	41	41	41	41	41	41
Industrial 1	79	88	98	107	116	126	135	144	154	163
Irrigation 1	7	7	8	9	9	10	11	11	12	13
T&D Effic Impr	49	54	59	64	70	75	80	85	90	96
Industrial 2	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	78	87	97	106	116	126	135	145	155	164
MF Res Weath	13	13	13	13	13	13	13	13	13	13
SF Res Weath	64	64	64	64	64	64	64	64	64	64
Ex. Res. Lighting-1	0	1	2	4	5	6	8	9	10	11
High Cost Block	2	8	16	24	32	40	48	56	64	72
Subtotal	840	903	969	1034	1102	1168	1229	1285	1346	1404
GENERATING RESOURCES:										
Hydro Eff Imp	75	75	75	75	75	75	75	75	75	75
Small Hydro 1	14	14	14	14	14	14	14	14	14	14
Small Hydro 2	11	11	14	14	14	14	14	14	14	14
WNP 3	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	6	6	6	6	6	6	6	6	6	6
Cogen 1	80	80	80	80	80	80	80	80	80	80
WNP 1	818	818	818	818	818	818	818	818	818	818
Mun. Solid Waste	0	0	0	0	0	0	0	8	8	8
Combined Cycle 1	357	357	357	714	714	714	714	714	714	714
Combined Cycle 2	0	0	0	0	357	357	714	714	1071	1071
Wind 1	0	0	6	6	6	6	6	6	6	6
Geothermal	0	0	35	35	35	35	35	35	35	35
Small Hydro 3	0	0	0	0	0	0	0	4	4	7
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	0
E. Wash Coal Gas	0	0	0	0	0	0	0	0	0	0
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	0
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0
Cogen 2	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0
Subtotal	2229	2229	2273	2630	2987	2987	3344	3356	3713	3716
Total Firm Resources	6846	6762	6644	6827	7088	7105	7418	7318	7556	7561
Load/Resource Balance	372	208	12	84	220	112	308	88	202	81

Study ID :8-APR-91 12:40:15
Study Title:High Gase Price Scenario - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = IOUs

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	9642	10059	10381	10709	11061	11407	11751	12045	12332	12636	12932	13232	13524	13842	14203	14557	14898	15246	15608	15970
Observed Rate	4.33%	3.20%	3.16%	3.29%	3.13%	3.01%	2.50%	2.39%	2.46%	2.34%	2.32%	2.21%	2.36%	2.60%	2.50%	2.34%	2.34%	2.37%	2.32%	
Existing Resources	9411	9392	9340	9287	9214	9141	8976	8811	8691	8571	8520	8469	8445	8388	8344	8184	8132	8142	8161	7923
BPA Requirements	107	138	188	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	8	24	41	60	79	98	118	138	161	186	211	235	250	257	262	265
New Commercial 1	0	3	6	16	34	55	77	100	123	147	170	193	217	242	268	292	318	344	371	398
Commercial R&R 1	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95
New SF Res 1	0	1	3	6	10	16	22	28	34	40	47	53	59	66	72	79	85	91	97	104
New MF Res 1	0	0	0	1	1	2	2	3	4	5	5	6	7	7	8	9	10	10	11	12
New Manuf Housing 1	0	1	2	4	7	12	16	20	25	30	35	39	44	49	53	58	63	67	72	76
New Res Light 1	0	0	1	2	4	6	8	9	11	13	15	17	19	22	24	26	27	29	31	33
Wtr Htr Heat Pumps	0	1	2	4	7	11	15	19	24	29	34	38	43	48	53	58	62	67	72	76
Cons. Volt. Reg.	0	3	9	15	21	27	33	38	44	50	56	59	59	59	59	59	59	59	59	59
Industrial 1	0	2	6	15	24	33	43	52	61	70	79	88	98	107	116	126	135	144	154	163
Irrigation 1	0	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
T&D Effic Impr	0	2	7	12	17	22	27	31	36	41	46	51	56	60	65	70	75	80	84	89
Industrial 2	0	1	4	10	16	23	29	35	41	48	54	60	67	73	80	86	93	99	106	112
Exist. Commercial 1	0	2	10	22	38	57	77	96	115	134	153	172	191	210	229	249	268	287	306	325
MF Res Weath	0	2	6	11	17	22	27	32	38	43	44	44	44	44	44	44	44	44	44	44
SF Res Weath	0	2	8	15	22	29	36	43	50	57	59	59	59	59	59	59	59	59	59	59
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	15	15	15	15	15	15	15	15	15
High Cost Block	0	0	0	0	0	0	0	0	0	0	3	12	24	36	48	60	72	84	96	108
Subtotal	0	26	77	154	254	375	496	617	744	871	991	1109	1234	1360	1487	1614	1730	1837	1946	2051
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	10	20	30	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Small Hydro 1	0	0	0	0	0	0	14	29	43	52	62	71	76	76	76	76	76	76	76	76
Small Hydro 2	0	0	0	0	0	0	11	22	33	43	51	58	65	72	80	87	87	87	87	87
Thermal Eff Imp	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Cogen 1	0	0	0	0	40	160	280	400	420	420	420	420	420	420	420	420	420	420	420	420
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	23	23	30
Combined Cycle 1	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357	357	357
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	357	357	357	357	357	357
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	280	280	280	280	280	280	280	280
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	107	107	107
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	597	597	895	1194	1492	1790	1790	1790	1790	1790	1790
E. Wash Coal Gas	0	0	0	0	0	523	785	785	785	785	785	785	785	785	785	785	785	785	785	785
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	262	262	262	262	262	262	262	523	785	785	785
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	263	263	526	790
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	263
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	50	60	110	880	1388	1976	2070	3328	3361	3686	4008	4331	4637	4644	5168	5438	5701	6235
Total Firm Resources	9519	9555	9654	9501	9579	10395	10859	11405	11505	12770	12871	13267	13687	14082	14470	14442	15031	15419	15809	16211
Load/Resource Balance	-123	-505	-726	-1208	-1482	-1012	-892	-639	-827	135	-60	35	164	239	267	-115	133	172	201	242

Study ID :8-APR-91 12:40:15
Study Title:High Gase Price Scenario - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = Generating Publics

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	4827	5043	5206	5373	5553	5730	5905	6055	6208	6369	6521	6675	6825	6989	7173	7355	7535	7719	7911	8103
Observed Rate	4.49%	3.23%	3.19%	3.35%	3.19%	3.06%	2.54%	2.52%	2.59%	2.39%	2.37%	2.24%	2.39%	2.64%	2.54%	2.45%	2.45%	2.48%	2.43%	
Existing Resources	2445	2432	2450	2468	2451	2435	2434	2433	2411	2390	2394	2398	2381	2365	2372	2496	2559	2559	2559	2699
BPA Requirements	2382	2611	2756	2905	3101	3295	3471	3441	3607	3781	3921	4064	4222	4392	4561	4616	4728	4903	5085	5134
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	3	9	16	22	29	36	44	52	61	70	79	88	94	96	98	99
New Commercial 1	0	1	2	5	10	15	21	27	33	40	45	51	58	64	71	77	84	90	97	105
Commercial R&R 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New SF Res 1	0	0	1	3	5	9	12	15	18	21	24	27	30	33	37	40	43	46	49	52
New MF Res 1	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3	3	3	4
New Manuf Housing 1	0	0	1	1	3	4	6	7	9	10	12	14	15	17	18	20	22	23	25	26
New Res Light 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wtr Htr Heat Pumps	0	0	0	0	1	2	4	6	8	10	12	13	15	17	19	21	23	25	27	29
Subtotal	0	1	4	9	22	40	60	78	98	118	139	159	181	203	226	249	269	283	299	315
GENERATING RESOURCES:																				
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	4827	5045	5211	5382	5575	5770	5964	5952	6116	6288	6453	6621	6785	6962	7160	7361	7554	7745	7943	8148
Load/Resource Balance	0	1	4	10	22	40	59	-103	-92	-81	-68	-54	-41	-27	-13	6	19	26	32	45

Study ID :8-APR-91 12:40:15
Study Title:High Gase Price Scenario - HIGH LOADS

SYSTEM SUMMARY:Observed Loads and Resources (Avg MW),PARTY = REGION

Operating Year	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05	05-06	06-07	07-08	08-09	09-10
Observed Load	17619	18363	18913	19496	20136	20768	21401	21946	22483	23050	23601	24161	24706	25299	25970	26631	27269	27920	28598	29278
Observed Rate	4.22%	3.00%	3.08%	3.29%	3.14%	3.05%	2.54%	2.45%	2.52%	2.39%	2.37%	2.26%	2.40%	2.65%	2.55%	2.40%	2.39%	2.43%	2.38%	
DSI Firm Load	2336	2314	2335	2357	2356	2355	2354	2354	2353	2352	2326	2301	2275	2275	2275	2275	2275	2275	2275	2275
Existing Resources	19300	19286	19239	19193	19150	19106	19071	19036	18849	18663	18611	18559	18449	18306	18276	18247	18263	18278	18304	18199
CONSERVATION PROGRAMS:																				
Water Heat 1	0	0	0	0	14	43	74	106	140	173	209	247	288	332	376	419	446	457	466	472
New Commercial 1	0	4	9	24	50	79	111	143	176	211	242	275	310	344	381	415	452	488	526	566
Commercial R&R 1	0	8	15	23	30	38	45	53	60	68	75	83	90	98	106	113	121	128	136	143
New SF Res 1	0	2	6	12	21	34	47	59	71	84	97	109	122	135	149	162	174	187	199	213
New MF Res 1	0	0	0	1	1	4	4	5	6	8	9	10	11	11	13	15	16	16	18	20
New Manuf Housing 1	0	1	4	7	13	20	28	35	43	51	60	68	75	84	91	100	108	115	124	131
New Res Light 1	0	0	2	3	6	10	13	16	19	22	26	29	32	37	40	44	46	49	53	56
Wtr Htr Heat Pumps	0	1	2	4	9	16	23	31	40	49	58	65	75	84	93	102	110	119	128	136
BPA Contract Recall	192	192	192	242	242	242	242	292	292	292	292	292	292	292	292	292	292	292	292	292
Cons. Volt. Reg.	0	5	15	25	35	45	56	65	75	85	95	100	100	100	100	100	100	100	100	100
Industrial 1	0	4	12	30	48	66	86	104	122	140	158	176	196	214	232	252	270	288	308	326
Irrigation 1	0	0	2	4	5	7	9	11	12	14	16	17	19	21	22	24	26	27	29	31
T&D Effic Impr	0	5	15	25	35	45	55	65	75	85	95	105	115	124	135	145	155	165	174	185
Industrial 2	0	2	8	20	32	46	58	70	82	96	108	120	134	146	160	172	186	198	212	224
Exist. Commercial 1	0	3	15	33	57	86	116	144	173	202	231	259	288	316	345	375	403	432	461	489
MF Res Weath	0	3	8	14	22	28	35	41	48	55	57	57	57	57	57	57	57	57	57	57
SF Res Weath	0	5	17	31	46	60	75	89	104	118	123	123	123	123	123	123	123	123	123	123
Ex. Res. Lighting-1	0	1	2	4	5	7	8	10	12	13	14	16	17	19	20	21	23	24	25	26
High Cost Block	0	0	0	0	0	0	0	0	0	0	5	20	40	60	80	100	120	140	160	180
Subtotal	192	236	324	502	671	876	1085	1339	1550	1766	1970	2171	2384	2597	2815	3031	3228	3405	3591	3770
GENERATING RESOURCES:																				
Hydro Eff Imp	0	0	0	25	50	75	95	110	110	110	110	110	110	110	110	110	110	110	110	110
Small Hydro 1	0	0	0	0	0	0	19	39	57	66	76	85	90	90	90	90	90	90	90	90
Small Hydro 2	0	0	0	0	0	0	15	29	44	54	62	69	79	86	94	101	101	101	101	101
WNP 3	0	0	0	0	0	0	0	0	868	868	868	868	868	868	868	868	868	868	868	868
Thermal Eff Imp	0	0	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Cogen 1	0	0	0	0	40	180	340	480	500	500	500	500	500	500	500	500	500	500	500	500
WNP 1	0	0	0	0	0	0	0	0	0	818	818	818	818	818	818	818	818	818	818	818
Mun. Solid Waste	0	0	0	0	0	0	0	0	0	8	8	8	8	15	15	15	15	31	31	38
Combined Cycle 1	0	0	0	0	0	0	0	357	714	714	714	714	714	1071	1071	1071	1071	1071	1071	1071
Combined Cycle 2	0	0	0	0	0	0	0	0	0	357	357	357	357	357	714	714	1071	1071	1428	1428
Wind 1	0	0	0	0	0	12	23	23	23	23	23	23	29	29	29	29	29	29	29	29
Geothermal	0	0	0	0	0	105	175	245	280	280	280	280	315	315	315	315	315	315	315	315
Small Hydro 3	0	0	0	0	0	0	15	30	44	59	74	85	96	107	107	107	107	111	111	114
E. Mont Coal Gas	0	0	0	0	0	0	0	0	0	597	597	895	1194	1492	1790	1790	1790	1790	1790	1790
E. Wash Coal Gas	0	0	0	0	0	523	785	785	785	785	785	785	785	785	785	785	785	785	785	785
E. Oregon Coal Gas	0	0	0	0	0	0	0	0	0	262	262	262	262	262	262	262	523	785	785	785
W. Wa/Or Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	263	263	526	790
Nevada Coal Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	263
Cogen 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	56	81	146	951	1523	2154	3481	5557	5590	5915	6281	6961	7624	7631	8512	8794	9414	9951
Total Firm Resources	19493	19521	19619	19778	19970	20933	21675	22529	23882	25986	26171	26650	27116	27870	28718	28909	30003	30482	31308	31920
Load/Resource Balance	-462	-1156	-1630	-2074	-2522	-2190	-2081	-1770	-954	584	243	189	135	296	474	3	460	286	435	367

CHAPTER 11

RESOURCE ACQUISITION

Introduction

This chapter addresses a variety of issues that arise in conjunction with the acquisition of both generation and conservation resources. Most of these issues relate to acquisitions by utilities in the region, as well as to the Bonneville Power Administration.

Part 1 sets forth general principles for resource acquisition. The Council believes these principles should be applied in all resource acquisitions, regardless of whether the resource is acquired by Bonneville or another utility.

Part 2 describes a general process for acquiring resources. The Council recommends this process as one way of ensuring resource acquisition decisions that will result in a least-cost energy future for the region.

Part 3 states some generally applicable fish and wildlife considerations. While these are directed primarily at hydroelectric projects, they should be taken into consideration when acquiring any resource that has an impact on the natural environment.

Part 4 deals with a type of acquisition unique to Bonneville, the acquisition of power system reserves through the sale of additional power to existing direct service industrial customers under Section 5(d)(3) of the Northwest Power Act.

Part 1: General Principles Governing Resource Acquisition

In the Northwest Power Act, Congress intended that all of the Bonneville Power Administration's acquisition activities "shall be consistent with the plan," unless specifically exempted under the Act (Section 4(d)(2)). The Council believes the principles set forth below are equally valid for all resource acquisitions, whether made by Bonneville or another utility.

All resource acquisition efforts must be designed to be consistent with the following principles:

1. Acquisition efforts should not create lost-opportunity resources and should develop as much of a resource as is cost-effective to the region. A lost-opportunity resource is one that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken now to develop it or hold it for future use. A practice known as "cream skimming" is one way of creating a lost-opportunity resource. An example is installing only the easiest and least expensive conservation measures, so that it may not be cost-effective to return to install added measures. These additional measures would have been cost-effective if they had been installed the first time.

2. Acquisition efforts should develop resources in the most cost-effective manner possible. Expenditures for conservation resources should recognize that administrative costs and incentive payments must be balanced to achieve the lowest overall cost for the resource. Under some circumstances, for example, it may be more cost-effective to pay the entire cost of the conservation measures than to incur the administrative costs associated with partial payments. Utilities also should examine acquisition approaches that may reduce transaction costs. It is possible that competitive negotiation could reduce such costs.

3. Acquisition efforts should acknowledge that for certain resources there is a limited "window of opportunity" during which all of a resource that is cost-effective should be secured. It is important to match acquisition activities with the schedules of host facilities, especially in the case of certain conservation acquisitions. In industrial plants, for example, retrofit activities should match a plant's scheduled downtime; in the commercial sector, measures should be installed at the time of renovation; and in all sectors,

code efforts should move to the full regionally cost-effective limit whenever the legislative or administrative process addresses energy efficiency.

4. Efforts to acquire conservation should ensure that regionally cost-effective levels of efficiency are economically feasible for the consumer. An economically feasible conservation investment is one that results in the lowest life-cycle cost to the consumer. Conservation investments beyond that point, as long as they result in savings that are cost-effective for the region, should be paid for by the region's utilities.

5. The benefits of conservation acquisition efforts should be distributed equitably throughout the region.

6. Acquisition efforts should maintain or enhance environmental quality. Acquisitions that lead to environmental degradation should be avoided or minimized.

7. Acquisition efforts should enhance the region's ability to shorten resource development lead times, reduce development costs and increase the variety of available resources. Efforts to shorten the overall lead time required to develop a resource will help reduce the cost of new resources. Completing the preliminary development steps and then holding a project so that the decision to construct may more closely match a demonstrated need for power also will serve to reduce developers' financial risk. Building the capability to acquire conservation resources will ensure that the region is able to capture efficiency savings as the need arises.

8. Conservation acquisition efforts should ensure that the acquisition mechanism is as efficient as possible and that resources are reliably producing actual savings. These efforts should be evaluated with respect to process and results. These evaluations should be designed to provide reliable information that can be used to verify resource cost and output, and to improve future efforts and estimates of resource cost and availability.

9. Conservation acquisition efforts should be restricted to promoting electrical energy efficiency and should not be used to increase the market penetration of electric utilities. Marketing programs may be one effective means of promoting energy-efficient building practices, but such efforts should not result in significant fuel switching.

10. Acquisition efforts should give credit for resource characteristics that are not specifically accounted for in the Council's planning models. Certain resources, such as conservation or on-site generation, may help the region avoid the need to reinforce the power system with added line extensions or new transformers. For example, the Puget Sound area is experiencing transmission capacity constraints. If conservation reduces the need to reinforce the system there, it should be given added credit.

11. Acquisition efforts in conservation should not be reduced simply because some consumers might otherwise have invested their own money in some part of the resource. Utility acquisition of regionally cost-effective conservation may sometimes pay for measures that consumers would have purchased on their own. Concern for this "free rider" potential should not keep utilities from purchasing all regionally cost-effective conservation.

Part 2: A Process for Resource Acquisition

Resource development can be a long, costly and risky proposition. Large generating projects can cost hundreds of millions of dollars. If such plants are constructed, but prove unnecessary, utilities face the very expensive prospect that public utility commissions will be unwilling to include the utilities' investment in rates. Therefore, to the extent that the decision to construct a new plant can be moved closer to the actual time of need, the developer faces substantially less risk.

The Council decided that one way to help reduce this risk was to design an overall approach to acquisition that could accommodate resource development by Bonneville, regional utilities or private developers. A key feature of the resource acquisition process is an "option" concept. If the designing, siting and preliminary licensing on a resource could be completed, and then construction held off until later, a developer would effectively have an "option" on that resource. This approach draws a fundamental distinction between those initial activities that are less expensive, relative to the cost of constructing a large generating plant, and a second stage of resource development activities that commences with the decision to build. If a resource can be held until a subsequent decision to build becomes appropriate, a developer, and the region at-large, can be much more confident that additional load can be served. Both reduced financial risk and added security in being able to meet future load growth make the options concept a useful element of regional planning.

The options concept has been widely discussed and largely accepted by the region's utility community. This process to shorten lead times on resources in the plan should receive favorable regulatory treatment to allow the region's utilities to meet the range of future load growth at the lowest possible cost.

While the term "option" is used in this chapter to describe actions to shorten lead times, the Council recognizes that shortening lead times also may refer to reducing the overall time required between initial conception and actual operation of a plant. For more information, see Volume I, pages 36 and 37.

The Council realizes that not all resources will need a waiting period between the preliminary steps and the decision to build. There is no added value in holding an option if it is already clear that added demand calls for new resources. In this latter case, the model process outlined below can be telescoped, passing quickly through the steps that relate to acquiring and holding an option.

For resources that are not to be kept on hold, the Council recognizes that there are numerous approaches to acquisition that may fulfill the plan's goal of providing a least-cost energy future for the region. Traditional negotiation, competitive acquisition and billing credits are just some of the mechanisms Bonneville and the other utilities may use to acquire resources. Whatever the acquisition mechanism, resources selected for Bonneville acquisitions should be consistent with the regional least-cost plan, and resources acquired by investor-owned utilities should be consistent with each utility's least-cost plan. The Council expects that these individual plans will have been tested by the public utility commissions for consistency with the regional plan.

The model process requires a number of actions by several different entities (see Figure 11-1). The most important actions are described in the discussion that follows. The development of any specific resource may require modification of the steps outlined in the model process presented here.

This process takes as its starting point the Council's plan with its estimated need for new resources, as well as the portfolio of least-cost resources to meet that need. The plan also calls for incorporating options in the Action Plan. Utility selection of specific resources, followed by the state and federal siting and licensing decisions, will allow the flexibility to construct the lowest cost resources. Opportunities for significant public involvement have been included throughout this model process. The various entities involved in taking the steps required to shorten resource lead times and the respective activities of those entities are discussed below.

I. Develop Option Evaluation Procedure

Before acquiring a resource option, utilities need to develop procedures for evaluating and selecting among candidate options. A procedure allows the utility to assess competing alternatives at various stages of the option process and to identify the best alternatives.

A. Procedure for Council Review and for Addressing Environmental and Fish and Wildlife Considerations

Bonneville and the Council have developed a procedure for complying with 1) the requirements of Section 6(c) of the Northwest Power Act, which provides for Bonneville and Council review of all Bonneville resource acquisitions greater than 50 average megawatts to ensure they are consistent with the Council's power plan; and 2) the National Environmental Policy Act (NEPA). These procedures identify when major Bonneville decisions will be made and allow for appropriate input from all interested parties. The procedure for Council review will consider whether a specific resource is consistent with the goals and objectives in the Council's plan and whether the project can be developed in an environmentally acceptable and cost-effective manner. The Council also will review projects to determine their consistency with the Council's Columbia River Basin Fish and Wildlife Program, as noted below.

B. Option Evaluation Procedure

An effective options evaluation procedure should begin with an agreement among Bonneville, the Council, utilities, the host state and appropriate local governments to implement a joint hearings process to complete all NEPA and Northwest Power Act reviews, and to secure all state and local licenses for resource options. This is not the step at which a decision to construct the resource would be made, and further environmental review might be necessary when that decision is made. The procedures for evaluating and selecting projects should appear in the requests for qualifications and requests for proposals made to utilities and independent developers.

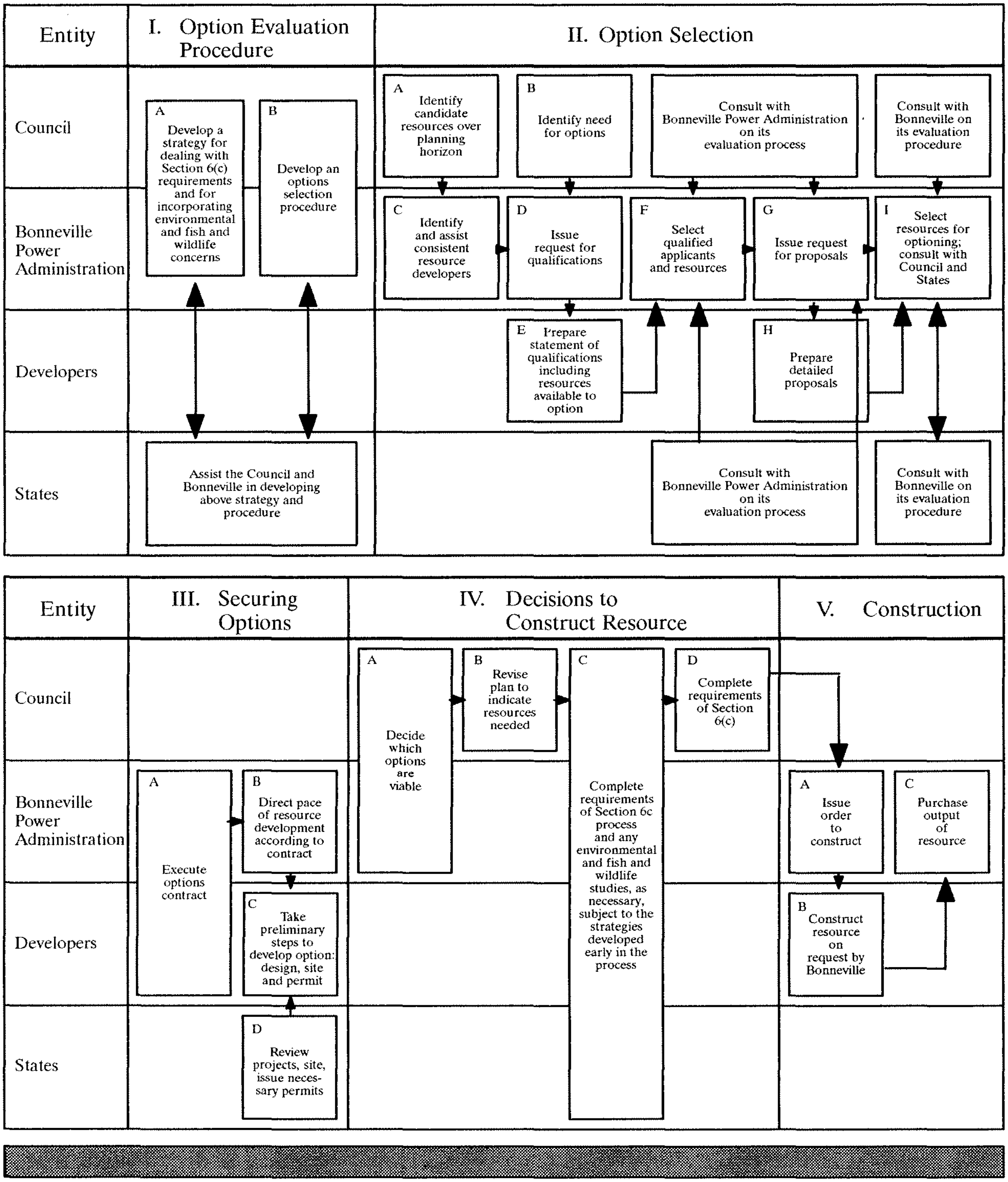
II. Option Selection

The Council envisions that the selection process will occur during a "window of opportunity" when prospective resource developers will respond to a request for proposal. The window would close when options have been secured on a sufficient number of proposed resources to build an adequate inventory of resources "on hold." It would reopen when the inventory has fallen below an established threshold level. The concept of soliciting bids from resource developers is an important part of the selection process, one that will encourage competition and help ensure that low-cost resources are acquired first.

The goal of a procedure to select options should be to minimize overall costs to the region's electrical system and to avoid unnecessarily burdening resource developers with process. However, there may be a large number of potentially acceptable projects within the region for certain resource types, such as cogeneration and hydropower. It may be desirable to use a preliminary screening process for these resources before issuing a formal request for bids.

Acquiring Resources

Figure 11-1
One Approach to Acquiring Resources



A preliminary screening may have several benefits. Some projects may be obviously unsuitable for technical, economical or environmental reasons. They can be eliminated at this stage, thus reducing the sponsors' and utilities' time and effort for proposal preparation and review, respectively. Furthermore, projects that pass the initial screening are likely to be viewed by their sponsors as having greater potential. As a result, qualifying sponsors are likely to put more effort into developing their proposals, thereby providing better evidence for the selection of prospective options. Preliminary screening may not be feasible or desirable for resource types with only a few candidates and a pre-bidding conference could suffice.

A. Identify Candidate Resources

In the plan, the Council has identified categories of conservation and generation resources and the order in which they should be acquired to meet the forecast range of future load uncertainty. These categories provide the basis for selecting options that would be consistent with the Council's plan. It is expected that future revisions to the plan will continue to identify the amounts, categories and schedules of conservation and generation resources required to meet future loads.

B. Identify Need for Options

The options concept will significantly alter the region's selection process for new generating resources. The Council will identify categories of resources and call for options to meet a range of load growth projections. The Action Plan specifies the need to acquire options for these resources.

C. Identify Resources and Assist Resource Developers

Utilities will identify specific projects they believe are consistent with the plan and provide technical assistance to developers to assess their resources. Through this effort, Bonneville can help to secure a broad base of option candidates while ensuring against the loss of resource opportunities that are consistent with the Council's plan. Specific resources will be identified for acquisition through a process that begins with a request for qualifications and proceeds through a request for proposals from qualified developers.

D. Issue Request for Qualifications

Utilities may issue a request for qualifications. As a preliminary step, such a request gives notice of the request for option candidates and asks interested sponsors to submit statements of qualification. The request should provide information on the kinds of options being sought, including the type and size of resource, development time frames and other key conditions and steps in the option and resource acquisition processes. The request for qualifications may be issued for a specified time period ("window of opportunity") during which any potential developers can respond with a statement of their qualifications. The Council expects that this open request will assist in identifying all of the potential developers with cost-effective resources in the region. This process could produce new information about the cost and availability of resources, which could lead to Council consideration of amendments to the power plan.

This step and the next two steps may be reduced to a pre-bidding conference. At this conference, utilities would brief potential resource developers on the characteristics of projects that are to be solicited in the request for proposal. The purpose of the conference would be to indicate the types of projects that are sought and the characteristics of each project that is likely to be optioned.

E. Prepare Statement of Qualification

Interested resource sponsors may prepare brief statements of qualification for their projects. These statements should contain information regarding the qualifications of the project and sponsor regarding the proposed acquisition of options.

F. Select Qualifying Developers and Projects

Utilities will review the statements of qualification and, in consultation with regulators, the Council, and state and local governments, select those that appear to qualify as prospective options.

G. Issue Request for Proposal

Based on the results of the request for qualifications, utilities may issue a request for proposal and invite selected resource developers to enter into options contracts. The request for proposal process will be open for a specified period or until a specified number of resources are selected. It will set forth in detail the technical, economic, environmental, fish and wildlife and institutional characteristics of the resources sought for optioning, as well as describe the options evaluation process, the process of purchasing options and the overall resource acquisition process. Prior to issuing a request for proposal, utilities need to consult with the various state agencies and the public on the specific types of resource options being requested. This step will ensure consistency with the directions of the plan.

H. Prepare Detailed Proposal

Prospective resource developers interested in entering into an option agreement would prepare a detailed proposal to offer their resource for optioning. This proposal should contain information on the technical, economic, environmental, fish and wildlife, and institutional characteristics of their project in enough detail to permit determination of its suitability as an option.

I. Select Prospective Options

Upon receiving option proposals from resource developers, utilities will use the evaluation procedure and methods described in the request for proposal. This evaluation will include consultation with the states to address site-specific concerns, and with the Council to ensure that selected options are consistent with the Council's plan. After these consultations, utilities will enter into formal negotiations with resource developers to purchase an option on the resource.

III. Securing Options

Option contracts signed at this step will provide for completing all requirements of the pre-construction phase of development. This typically will require completion of preliminary engineering design and environmental assessment and securing the state and federal permits and licenses required for construction. Either sites will be purchased or options to purchase them will be acquired. For this first phase of the acquisition process to work, resource developers' costs must be appropriately compensated by the utilities, and utilities should be granted appropriate rate treatment by the public utility commissions.

A. Execute Option Contract

Based on the expected cost-effectiveness of the project and the negotiations between the utilities and the resource developer, a contract will be offered to purchase an option on the project. This contract will identify the legal rights of the utility and the developer. At a minimum, these rights will include the utility's ability to direct the construction start date and the pace of development.

The Council recognizes that the specific terms and conditions of these option contracts will govern both the cost and viability of this acquisition approach. For this reason, the Council will work with Bonneville, resource developers and utilities to develop viable option contracts.

B. Direction of Resource Development

Utilities will direct the start and pace of project development. This will allow utilities to match the timing of the build decision to the evolving need for resources in the region.

C. Develop Options

Resource developers will secure an option as directed by utilities in the contract and pursuant to state, federal and local licenses and permits. At this point, developers will complete the key steps of siting, licensing and designing the project. The utilities then could decide to complete construction or to hold the option until needs dictated its construction.

Not all projects will be carried through the option phase of development. The economic attractiveness of some projects may wane as engineering design advances. Other projects may fail to qualify for necessary permits and licenses. Nor is it expected that all projects for which permits and licenses are obtained will necessarily be constructed. For example, following completion of the preliminary steps, utilities may wish to relinquish projects that subsequent analysis indicates are not reliable, are less cost-effective than other potential resources or are environmentally unacceptable. Of course, if the procedures to select options are effective, the failure rate should be low. But it is important to recognize that not all options ultimately will be built.

D. State Review of Projects and Issuance of Necessary Licenses and Permits

In response to material submitted by utilities, the Council and the developer, each state should review the project and decide whether to issue the licenses and permits necessary to complete the project when it is needed. This review will encompass all siting and licensing issues with the exception of the critical determination of the actual need for power. Final need will be established as part of the "decision to construct" process.

A joint hearings process could be designed, preferably taking the form of a generic "memorandum of understanding" among each state, Bonneville and the Council. Sub-agreements for each proposed option should reflect any unique considerations and incorporate participation of the appropriate local governments and federal agencies. The memorandum of understanding could have the following features:

1. All federal, state and local decision-makers should be recognized explicitly as independent bodies whose authorities will not be abridged, but who have agreed to conduct a single administrative proceeding. In the proceedings, each decision-maker can choose the level of its participation, as long as decisions are made promptly.

2. A single administrative process could be established to meet the needs of all decision-makers. A single notice of hearings, which explains to the public how the process will work, could be used by all decision-makers. Opportunities for legislative and contested case formats could be included to meet all administrative requirements. The scope of issues would be identified by the decision-makers at the outset. The information and evidence requirements of each decision-maker could be identified at the outset, so that the applicant may minimize duplicative studies and reports. The

process should have a definite schedule. A single hearings examiner, possibly from the state, would administer the hearings. Each decision-maker would be free to ask questions or to request additional information.

3. There should be a process for holding hearings on specific issues at the decision-to-construct stage. These hearings should address questions of need for power and any significant new information.

It is expected that utilities, Bonneville and the Council will consult with the states in the process of developing these review procedures. It also is expected that the states will have a significant role in the application of the evaluation procedures.

IV. Decisions to Construct Resources

At this stage, developers would make the decision to acquire and construct resources to meet regional load. The decision to begin construction is separate from the decision to begin siting and licensing, and one that may be delayed, in the absence of an immediate need for power. By making a second decision—a decision to start construction based on current loads and resources—the probability and cost of overbuilding resources will be reduced. Prior to commencing construction, utilities in consultation with the Council would again examine the inventory of options to see that the lowest-cost resources were being constructed. It also would be prudent before construction begins to assess whether other lower-cost resources exist outside of the inventory of options.

A. Monitor Viability of Secured Options

As noted above, it is possible that some resources that have been optioned will never be constructed. Holding an optioned resource beyond a reasonable lifetime could result in technical or economic problems or regulatory obsolescence. Utilities could extend options for which licenses or permits are about to expire or for which there have been significant technological advances. They would do so by repeating the previously described steps to decide if the project remains an attractive resource. In certain cases, it may be desirable to update the design of the resource to be consistent with current regulatory and environmental standards. In any event, utilities must determine which options remain viable.

B. Identify Need for Resources

During its normal planning cycle, the Council will revise the plan to update both the inventory of options and to recommend that construction begin on particular optioned projects. The normal Council process of public review and comment, including hearings throughout the region, will provide the basis for a regional consensus both on the viability of options that have been previously secured and on the prudence of beginning construction on cost-effective and environmentally sound projects.

C. Consistency with the Power Plan and the Northwest Power Act

In addition to meeting the requirements found in the acquisition principles in Part 1, certain acquisitions by Bonneville must undergo a review procedure set forth in Section 6(c) of the Northwest Power Act. The purpose of the procedure is to test consistency with the plan. The Act requires Bonneville to perform a public review process on any Bonneville proposal to acquire a major resource or to implement a conservation measure that will conserve an amount of electrical power equivalent to a major resource and to determine whether the proposed resource acquisition is consistent with the Council's power plan. A major resource is any resource larger than 50 average megawatts that is acquired by Bonneville for a period of more than five years.

The Act also provides that "the Council may determine by majority vote of all members of the Council, and notify the administrator that the proposal is either consistent or inconsistent with the plan" (Section 6(c)(2)). If either Bonneville or the Council finds the proposal inconsistent with the plan, Bonneville must get congressional approval before it can proceed with the acquisition.

In November 1986, after a review process in which both Bonneville and the Council accepted broad-based public comment, each agency adopted a statement of policy regarding its obligations under Section 6(c). The Council decided that when it elects to review a Bonneville proposal it will do so by a majority vote of all the members, within 60 days of receiving the Bonneville administrator's determination made pursuant to Section 6(c)(1). The Council also outlined the approaches it expects to pursue to inform itself regarding the proposal. The Council adopted the following standard for finding consistency.

> A Bonneville proposal pursuant to Section 6(c)(1) of the Northwest Power Act shall be found consistent with the Northwest Conservation and Electric Power Plan, if it is judged to be so structured that it will achieve substantially the goals and objectives of the plan in effect at the time the proposal is made.

The Council's policy was issued on November 12, 1986, and the complete text is available from the public affairs division of the Council's central office (request "Statement of Policy—Implementing Section 6(c)").

In practice, the Council expects that this review process should be particularly expeditious in the case of resources that have gone through the preliminary steps, but then were placed on hold. Much of the review required to determine consistency with the plan already will have been completed in the preliminary steps outlined in this acquisition process. All interested parties, including state and local governments, will have had the opportunity to address the question of consistency. Unless new information is revealed in either Bonneville's or the Council's Section 6(c) review, it is expected that the resource will be found to be consistent with the plan.

Following a finding of consistency by the Council, Bonneville will direct the developer of the resource to commence construction.

V. Construct Resource

At this step in the process, the resource developer, with appropriate financial backing, will construct the resource. Rapid cost escalations and/or major design problems during construction could cause a re-evaluation of resources on which construction has begun. Even though uncertainty can be reduced through successful implementation of the options concept, it is still possible that some projects may not be completed as planned. The Council factors into its planning the probabilities that resources could be lost at some stage of the acquisition process and that replacement resources may be needed.

Part 3: Conditions for Hydropower Development

In response to the Northwest Power Act, the Council includes the following conditions in its plan, which requires due consideration for protection, mitigation and enhancement of fish and wildlife, related spawning grounds and habitat.

I. Protection, Mitigation and Enhancement of Fish

Bonneville should not agree to acquire power from, grant billing credits for, or take any other actions under Section 6 of the Act, concerning any hydropower development in the region without providing for:

1. consultation with interested fish and wildlife agencies and tribes, state water management agencies, and the Council throughout study, design, construction, and operation of the project;

2. specific plans for flows and fish passage facilities prior to construction;

3. the best available means for aiding downstream and upstream migration of salmon and steelhead;

4. flows and reservoir levels of sufficient quantity and quality to protect spawning, incubation, rearing and migration;

5. full compensation for unavoidable fish or fish habitat losses through habitat restoration or replacement, appropriate propagation, or similar measures that give preference to natural propagation over artificial production of fish;

6. assurance that the project will not inundate the usual and accustomed fishing and hunting places of any tribe;

7. assurance that the project will not degrade fish habitat or reduce numbers of fish in such a way that the exercise of treaty rights will be diminished; and

8. assurance that all fish protection and mitigation measures will be fully operational at the time the project commences.

II. Protection, Mitigation and Enhancement of Wildlife

Bonneville should not agree to acquire power from, grant billing credits for, or take other actions under Section 6 of the Act concerning any hydropower development in the region without providing for:

1. consultation with interested wildlife agencies and tribes, state water management agencies and the Council throughout study, design, construction and operation of the project;

2. avoiding inundation of wildlife habitat, such as winter range or migration routes essential to sustain local or migratory populations of significant wildlife species, insofar as practical;

3. timing construction activities, insofar as is practical, to reduce adverse effects on nesting and wintering grounds;

4. locating temporary access roads in areas to be inundated;

5. constructing subimpoundments and using all suitable excavated material to create islands, if appropriate, before the reservoir is filled;

6. avoiding all unnecessary or premature clearing of all land before filling the reservoir;

7. providing artificial nest structures, when appropriate;

8. avoiding construction, insofar as is practical, within 250 meters of active raptor nests;

9. avoiding critical riparian habitat (as defined in consultation with the wildlife agencies and tribes) when clearing, riprapping, dredging, disposing of spoils and wastes, constructing diversions, and relocating structures and facilities;

10. replacing riparian vegetation if natural revegetation is inadequate;

11. creating subimpoundments by diking backwater slough areas and creating islands, level ditchings, and nesting structures and areas;

12. regulating water levels to reduce adverse effects on wildlife during critical wildlife periods (as defined in consultation with the fish and wildlife agencies and tribes);

13. improving the wildlife carrying capacity of undisturbed portions of new project areas (through such activities as managing vegetation, reducing disturbance, and supplying food, cover and water) as compensation for otherwise unmitigated harm to wildlife and habitat in other parts of the project area;

14. acquiring land or management rights where necessary to compensate for lost wildlife habitat at the same time other project land is acquired, and including the associated costs in project cost estimates;

15. funding operation and management of the acquired wildlife land for the life of the project;

16. granting management easement rights on the acquired wildlife lands to appropriate management entities; and

17. collecting data needed to monitor and evaluate the results of the wildlife protection efforts.

III. Protected Areas

Conflicts over the development of hydropower projects in critical fish and wildlife areas generate cost and uncertainty for the region's power system. Mitigating the effects of hydropower development on fish and wildlife is risky, expensive and time consuming. Lengthy disputes have occurred over the possible effects of development and over the likelihood that mitigation may be successful. Not only are these disputes disruptive, but they add to developer costs and utility rates, and leave the region less certain about its ability to develop new resources when they are needed.

The Council directed extensive studies of fish and wildlife, their spawning grounds and habitat in the region, and analyzed alternative means of protecting them from further degradation. The Council concluded: 1) the studies have identified fish and wildlife resources that are of critical importance to the region; 2) mitigation techniques cannot ensure that all adverse impacts of hydroelectric development on these fish and wildlife can be mitigated; 3) even small hydroelectric projects may have unacceptable individual and cumulative impacts on these resources; 4) because of the likely cost and difficulty of developing hydroelectric projects in protected areas, the Council considers these projects unlikely to be reliable and available within the time needed for purposes of cost-effectiveness determinations under the Northwest Power Act; and 5) protecting these resources and habitats from hydroelectric development is consistent with an adequate, efficient, economical and reliable power supply. Accordingly, the Council, relying on these studies, has designated certain river reaches in the region as "protected areas." Protected areas are where the Council believes hydroelectric development would have unacceptable risk of loss to fish and wildlife species of concern, their productive capacity and their habitat.

Standards for Bonneville and the Federal Energy Regulatory Commission for hydroelectric projects located in the Columbia River Basin are set forth in Section 1103 of the Council's Columbia River Basin Fish and Wildlife Program. Standards for Bonneville and the Federal Energy Regulatory Commission for hydroelectric projects located outside of the Columbia River Basin are as follows:

1. River reaches to be protected are those reaches or portions of river reaches listed on the "protected areas list" adopted by the Council on August 10, 1988, or as later amended by the Council. The fish or wildlife to be protected are those indicated on the list for each river reach on the protected areas list. The Council will supply a copy of the protected areas list free of charge on request.

2. Bonneville should not acquire power from hydroelectric facilities located in protected areas. The Council believes that the Long-Term Intertie Access Policy's reliance on protected areas is consistent with the Council's power plan and fish and wildlife program as they apply to fish and wildlife in the Columbia River Basin. The Council continues to recommend that Bonneville adopt a similar policy with respect to protected areas outside the Columbia River Basin.

3. The Federal Energy Regulatory Commission should consider the Council's protected area designations in licensing and exemption proceedings.

4. Protected area designations are not intended to apply to:

   a. any hydroelectric facility or its existing impoundment that had, as of August 10, 1988, been licensed or exempted from licensing by the Federal Energy Regulatory Commission;

   b. the relicensing of such a hydroelectric facility or its existing impoundment;

   c. any modification of an existing hydroelectric facility or its existing impoundment;

d. any addition of hydroelectric generation facilities to a non-hydroelectric dam or diversion structure.

5. For purposes of cost-effectiveness determinations under the Northwest Power Act, energy from projects located in protected areas is unlikely to be reliable and available within the time it is needed.

6. Amendments:

   a. Upon receiving a state or tribal comprehensive plan or state or tribal river, river basin or watershed plan, the Council will promptly and carefully consider amending the protected areas list to reflect relevant portions of a state or tribal plan. With regard to resident fish and wildlife, the Council recognizes that individual state and tribal interests are particularly strong.

   b. For other amendments to protected areas, the Council will follow the processes described in Section 1303 of the Columbia River Basin Fish and Wildlife Program.

Part 4: Acquisition of Reserves by Bonneville

Under Section 5(d)(3) of the Act, the Bonneville administrator has discretion to sell additional power to existing direct service industrial customers as a means of providing additional power system reserves for the region's firm loads. The Council is required by the Act to determine whether such a proposed sale and acquisition of reserves is consistent with the power plan.

In determining whether a particular proposed sale of power to an existing direct service industrial customer is consistent with the power plan, the Council will be guided by the following principles.

1. ***Case-by-case determination.*** Each sale of additional power to a direct service industry will be reviewed on its own merits. The Council has not determined whether there may be circumstances other than those described in paragraphs 2, 3 and 4 below, in which a sale of additional power to an existing direct service industrial customer may be consistent with the power plan. However, the Council believes that a sale that has the attributes described below has a higher probability of Council approval than one that does not have these attributes.

2. ***Nonfirm sales.*** Sales of additional interruptible (nonfirm) power that do not increase net firm resource costs for other customers of Bonneville are likely to be consistent with the power plan. Net firm resource costs mean the firm resource costs after taking into consideration the revenues from the sale of the interruptible power.

3. ***Firm sales should be the least costly.*** Sales of additional firm power to an existing direct service industrial customer are likely to be consistent with the power plan only when they result in serving the additional load in a manner that is the least costly to the regional power system, after taking into consideration alternative sources for the power, alternative locations for the load, availability and reliability of transmission, provision of reserves and related factors.

4. ***Effect of the proposed sale on power planning.*** Proposals for the sale of additional firm power to an existing direct service industry beyond its current entitlement should include a showing of how the sale will affect Bonneville's need for additional resources, and what resources are potentially available to serve the load.

Conclusion

The Council is keenly aware that the next decade will test the region's ability to acquire those resources that will ensure a least-cost energy future for the Northwest. The acquisition principles set forth by the Council should apply to any resource proposal. The Council believes that the model acquisition process outlined above is one important way to reduce the region's risk of over- or underbuilding its resource base. Shortening lead times by using the options process should serve as an important device for reducing risk and resource development cost. Of course, this process may require modification when applied to any particular resource acquisition.

The strategy of purchasing options should minimize the likelihood that loads and resources will be out of balance, because it will reduce the time between the decision to construct a resource and the actual need for the resource. The option process has the added advantage of allowing for the evaluation of the environmental consequences of particular resources both when an option is taken, as well as when the decision to construct is reached. State public utility commissions may offer important support of this approach to shortening lead times by affording favorable rate treatment to the acquisition of options.

In outlining the principles and proposed resource acquisition process, the Council also has noted the variety of other evaluations that must be made. Section 6(c) applies to certain Bonneville proposals to acquire resources. Section 5(d)(3) applies to others. In all cases, the fish and wildlife provisions of the Northwest Power Act must be met. Setting these requirements out in advance should give all interested parties greater certainty as the region takes up the challenge of acquiring sufficient resources to meet its energy future at the lowest overall cost.

CHAPTER 12

MODEL CONSERVATION STANDARDS AND SURCHARGE METHODOLOGY[1]

The Model Conservation Standards

Introduction

As directed by the Northwest Power Act, the Council has designed model conservation standards to produce all electricity savings that are cost-effective for the region. The standards are also designed to be economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to capturing all cost-effective power savings while maintaining consumer economic feasibility, the Council believes that the measures used to achieve the model conservation standards should provide reliable savings to the power system. The Council also believes that actions taken to achieve the standards should maintain, and possibly improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles, and so forth) found in typical buildings constructed before the first standards were adopted in 1983.

The Council has adopted six model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions, and the standard for conservation programs not covered explicitly by the other model conservation standards.

The Model Conservation Standards for New Electrically Heated Residential and Commercial Buildings

Bonneville and the region's utilities should acquire all electric energy conservation measure savings from new residential and new commercial buildings that are expected to cost less than 11 cents per kilowatt-hour in nominal 1990 dollars.[2] The Council believes that through a combination of Bonneville programs, other utility programs and codes, at least 85 percent of these savings should be achieved.

The Council is committed to capturing all achievable electricity savings from the standards as soon as possible. The Council believes that the task of capturing all regionally cost-effective electricity savings in new residential and commercial buildings can be accomplished best through a combination of more stringent state and local building codes and effective Bonneville and utility programs. State and local governments have the responsibility of securing, through local building codes, at least those energy savings that minimize a building's life-cycle cost of construction and operation. Bonneville and the region's utilities should secure all energy efficiency improvements above and beyond those captured by local code that are projected to produce regionally cost-effective electricity savings. Where codes or standards require consumers to invest in conservation measures that go beyond their minimum life-cycle cost, Bonneville and the region's utilities should provide financial assistance to consumers to ensure that such investments are economically feasible.

1. This chapter supersedes the Council's previous model conservation standards and surcharge methodology. These amended standards include the model conservation standards for the following: new electrically heated residential buildings, utility conservation programs for new residential buildings, all new commercial buildings, utility conservation programs for new commercial buildings, electric space-conditioning system conversions, and conservation activities not covered explicitly by the other model conservation standards. This amendment also includes the Council's recommended surcharge methodology.

2. See Volume II, Chapter 13, for a discussion of how the Council calculates nominal 1990 dollars.

The Council has established four model conservation standards affecting new buildings.[3] These four standards are set forth below.

1.0 The Model Conservation Standard for New Electrically Heated Residential Buildings

The Council's model conservation standard for new single-family and multifamily electrically heated residential buildings[4] is as follows: New electrically heated residential buildings are to be built to energy-efficiency levels at least equal to those that would be achieved by using the illustrative component performance paths displayed in Table 12-1 for each of the Northwest climate zones.[5] It is important to remember that these illustrative paths are provided as benchmarks against which other combinations of strategies and measures can be evaluated.

Tradeoffs may be made among the components, as long as the overall efficiency and indoor air quality of the building are at least equivalent to a building containing the measures listed in Table 12-1. Bonneville, in consultation with the Council, should develop other illustrative approaches for building to this standard and publish these approaches as a codified version of the standard.

2.0 The Model Conservation Standard for Utility Conservation Programs for New Residential Buildings[6]

The model conservation standard for utility conservation programs for new residential buildings is as follows: Utilities are required to do, in accordance with the requirements detailed below, one of the following: implement the Bonneville/utility new residential model conservation standards program; implement an equivalent alternative program; rely on building codes/utility service standards that capture all regionally cost-effective space heating, water heating and appliance energy savings; or establish service charges/fees for buildings and appliances that are not built to regionally cost-effective efficiency levels. The Bonneville/utility residential model conservation standards program consists of an aggressive marketing and financial assistance program made available to home builders by Bonneville and the local utility.[7] Under this program, a new residence is to be certified by the utility when it is equivalent in efficiency to a home that contains all regionally cost-effective conservation measures built into or installed in the home at time of construction.

Financial Assistance

Financial assistance offered through the Bonneville/utility new residential model conservation standards program should be no less than the difference in net present value between a house that minimizes *the consumer's* life-cycle cost of electric space heating, water heating, lighting and of using major electrical appliances and a house with these same end uses built to the maximum cost-effective levels of efficiency for *the region*. The maximum financial assistance should be the regional cost-effectiveness limit for lost-opportunity resources. Bonneville and the region's utilities should provide financial assistance at levels sufficient to achieve 85 percent of the savings that would be achieved if all residential buildings contained all regionally cost-effective conservation measures built into or installed in the home at time of construction. Efforts to achieve the model conservation standard's penetration goal should continue as long as the program remains regionally cost-effective. In evaluating the program's cost-effectiveness, all costs, including utility administrative costs and financial assistance payments, should be taken into account.

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3. For the sake of brevity, the terms "construction," "new construction," "new buildings," "new residential buildings," and "new commercial buildings" are used throughout this rule to include major remodels and renovations of existing buildings, where such renovations and remodels involve lost-opportunity resources.

4. Single-family residences are defined to include duplexes. Multifamily residences include triplexes and larger structures up to and including four-story, low-rise residential structures. This standard applies to site-built residences and not to residences that are regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983).

5. The Council has established climate zones for the region based on the number of heating degree days as follows: Zone 1—4,000-6,000 heating degree days; Zone 2—6,000-8,000 heating degree days; and Zone 3—over 8,000 heating degree days.

6. This standard applies to site-built residences *and* to residences which are regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983).

7. Super Good Cents is the current name given to the Bonneville marketing program to encourage residential construction at the model conservation standards level of efficiency. Bonneville should review its current Super Good Cents program to ensure that this program secures all regionally cost-effective savings in as efficient and innovative a manner as possible.

Table 12-1
Illustrative Paths for the Model Conservation Standard for New Electrically Heated Residential Buildings

Component	Climate Zone Zone 1	Zone 2	Zone 3
Ceilings			
▪ Attic	R-38 (U-0.031)[a]	R-38 (U-0.031)[a]	R-49 (U-0.020)[b]
▪ Vaults	R-38 (U-0.027)	R-38 (U-0.027)	R-38 (U-0.027)
Walls			
▪ Above Grade[c]	R-19 (U-0.058)	R-24 (U-0.044)	R-26 (U-0.040)
▪ Below Grade[d]	R-19	R-19	R-19
Floors			
▪ Crawlspaces and Unheated Basements	R-30 (U-0.029)	R-30 (U-0.029)	R-30 (U-0.029)
▪ Slab-on-grade Perimeters[e]	R-10	R-10	R-10
Glazing[f]	R-2.5 (U-0.40)	R-2.5 (U-0.40)	R-2.5 (U-0.40)
Maximum Glazed Area (% floor area)	15	15	15
Exterior Doors	R-5 (U-0.19)	R-5 (U-0.19)	R-5 (U-0.19)
Assumed Thermal Infiltration Rate[g]	0.35 ach	0.35 ach	0.35 ach
Mechanical Ventilation[h]	See footnote h, below.	See footnote h, below.	
Service Water Heater	Energy Factor = 0.95	Energy Factor = 0.95	

[a] R-values listed in this table are for the insulation only. U-factors listed in this table are for the full assembly of the respective component and are based on the methodology defined in the *Super Good Cents Heat Loss Reference—Volume I: Heat Loss Assumptions and Calculations and Super Good Cents Heat Loss Reference—Volume II—Heat Loss Coefficient Tables*, Bonneville Power Administration (October 1988).

[b] Attics in single-family structures in Zone 3 shall be framed using techniques to ensure full insulation depth to the exterior of the wall. Attics in multifamily buildings in Zone 3 shall be insulated to nominal R-38 (U-0.031).

[c] All walls are assumed to be built using advanced framing techniques (e.g., studs on 24-inch centers, insulated headers above doors and windows, and so forth) that minimize unnecessary framing materials and reduce thermal short circuits. Multifamily exterior walls above grade in Zone 3 shall be insulated to a nominal R-24 (U-0.044).

[d] Only the R-value is listed for below-grade wall insulation. The corresponding heat-loss coefficient varies due to differences in local soil conditions and building configuration. Heat-loss coefficients for below-grade insulation should be taken from the Super Good Cents references listed in footnote "a" for the appropriate soil condition and building geometry.

[e] Only the R-value is listed for slab-edge insulation. The corresponding heat-loss coefficient varies due to differences in local soil conditions and building configuration. Heat-loss coefficients for slab-edge insulation should be taken from the Super Good Cents references listed in footnote "a" for the appropriate soil condition and building geometry and assuming a thermally broken slab.

Table 12-1 (cont.)
Illustrative Paths for the Model Conservation Standard for New Electrically Heated Residential Buildings

[f] U-factors for glazing shall be the tested values for thermal transmittance due to conduction obtained by use of either the American Architectural Manufacturers Association (AAMA) 1503.1-1988 test procedure or the American Society for Testing and Materials (ASTM) C236 or C976 test procedures. Testing shall be conducted under established winter horizontal heat-flow test conditions using a 15-mile-per-hour wind speed and product sample sizes specified under AAMA 1503.1-1988. Testing shall be conducted by a certified testing laboratory. When insulating glass is used, it shall be tested and certified under a Society of Insulated Glass Manufacturers of America (SIGMA) approved certification program as class "A," in accordance with ASTM E-744-81. **EXCEPTION**: Site-built fixed glazing shall be exempt from the thermal testing requirements, provided that it is installed either in an aluminum frame having a minimum 0.25-inch low-conductance thermal break or in vinyl or wood framing in accordance with SIGMA glazing specifications; and provided further that site-built, double-glazed units with fixed panes shall have a dead air space between panes of not less than 1/2 inch and site-built, triple-glazed units with fixed panes shall have a dead air space between panes of not less than 1/4 inch.

[g] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage.

[h] Indoor air quality should be comparable to levels found in non-model conservation standards dwellings built in 1983. To ensure that indoor air quality comparable to 1983 practice is achieved, Bonneville's programs must include pollutant source control (including, but not limited to, combustion by-products, radon and formaldehyde), pollutant monitoring, and mechanical ventilation, that may, but need not, include heat recovery. An example of source control is a requirement that wood stoves and fireplaces be provided with an outside source of combustion air. At a minimum, mechanical ventilation shall have the capability of providing the outdoor air quantities specified in the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62-89, *Ventilation for Acceptable Indoor Air Quality*. Natural ventilation through operable exterior openings and infiltration shall not be considered acceptable substitutes for achieving the requirements specified in ASHRAE Standard 62-89.

Submission of Utility Plans for Compliance with the Model Conservation Standard for New Residential Programs

Utilities should submit a plan to Bonneville declaring how they intend to meet the model conservation standard for utility conservation programs for new residential buildings. The goal for such programs is to obtain, in combination with codes, service standards and/or fees and other regional programs at least 85 percent of the savings that would have been obtained if all new residential buildings had been constructed with all regionally cost-effective electric space heating, water heating and appliance efficiency measures built into or installed in the home at time of construction.[8] The dates Bonneville sets for utility plan submission and implementation should reflect the need for a smooth transition from the current Bonneville/utility model conservation standard program for new electrically heated residences (i.e., Super Good Cents or its equivalent) to the revised program. It also should reflect the urgent need to capture all regionally cost-effective lost-opportunity resources in new residential buildings. A utility may change its declaration, subject to the same Bonneville approvals required for the initial plan submissions.

There are several ways utilities can comply with the model conservation standard for utility conservation programs for new residential buildings. These are:

1. Submit to and have approved by Bonneville a declaration that a code for residential buildings that captures all regionally cost-effective space heating, water heating and appliance energy savings, has been or will be adopted and enforced by a state and/or local government no later than a date to be specified by Bonneville,[9] and annually thereafter.
2. Submit to Bonneville a declaration agreeing to adopt and implement the Bonneville/utility model conservation standard program for new electrically heated residential buildings not later than a date specified by Bonneville.
3. Submit to and have approved by Bonneville an alternative program that will be implemented and/or enforced not later than a date specified by Bonneville. This alternative program should be capable of providing savings equivalent to the Bonneville/utility new residential model conservation standards program and not duplicate the acquisition of other resources that are already in the Council's plan. Alternative programs may include, but are not limited to, state or local government or utility marketing programs, financial assistance, codes/utility service standards or fees that achieve all regionally cost-effective savings, or

8. Eighty-five percent is the level of compliance that the Council believes is achievable.

9. State and/or local adoption of codified versions of the model conservation standard for new electrically heated residential buildings (i.e., the Northwest Energy Code, December 1990), or an equivalent code does not satisfy the model conservation standard for utility conservation programs for new residential buildings because such codes do not capture all regionally cost-effective electricity savings.

combinations of these and/or other measures to encourage energy-efficient construction of new residential buildings and the installation of energy efficient water heaters and appliances, or other lost-opportunity conservation resources.

3.0 The Model Conservation Standard for New Commercial Buildings

The Council's model conservation standard for new commercial buildings is as follows: by January 1992, new commercial buildings and existing commercial buildings that undergo major remodels or renovations are to be constructed to achieve savings equivalent to those achievable through constructing buildings to the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) and the Illuminating Engineering Society of North America (IES) Standard 90.1—1989 *Energy Efficient Design of New Buildings Except Low-Rise Residential Buildings* with the following modifications:

1. The lighting requirements for new commercial buildings are those specified in Section 435.103 Lighting of the U.S. Department of Energy's *Energy Conservation Voluntary Performance Standard for New Commercial and Multifamily High Rise Residential Buildings* (10 CFR Part 435, January 30, 1989), except that determination of the Interior Lighting Power Allowance shall be based on the building's gross square footage and include only permanently installed lighting.

2. The minimum efficiencies for electric heating, ventilating, air conditioning, service water heating equipment and electric motors are those specified as applicable on January 1, 1992, in ASHRAE/IES Standard 90.1—1989 for all products not covered by the National Appliance Efficiency Act of 1987. The minimum efficiencies for equipment covered by the National Appliance Efficiency Act of 1987 are those set forth in that statute or developed through rulemaking pursuant to the statute.

3. The application of the "Building Energy Cost Budget Method" (Section 13 of ASHRAE/IES Standard 90.1—1989) shall be limited to the comparison of annual design energy use as an alternative compliance path.

4. The application of this standard to existing buildings shall be consistent with the intent of Section 101.3.2 (Application to Existing Buildings) of the *Northwest Energy Code, Model Conservation Standards Equivalent Code* (December 1990).

The Council finds that measures required to meet the ASHRAE/IES Standard 90.1—1989, as modified by this rule, are commercially available, reliable and economically feasible for consumers without financial assistance from Bonneville. The Council also finds that the measures required to meet the ASHRAE/IES 90.1—1989, as modified by this rule, do not capture all regionally cost-effective savings. In order to capture these savings, the Council has established a model conservation standard for utility conservation programs for new commercial buildings.

Illustrative ways for a commercial building to meet this standard are described in those portions of Bonneville's Model Conservation Standards Equivalent Code Amendments to the *Model Energy Code*, December 1990, or Model Conservation Standards Equivalent Code to Chapter 53 of the *Uniform Building Code*, December 1990, which apply to all buildings except low-rise residential buildings. As with the residential model conservation standard, flexibility is encouraged in designing paths to achieve the commercial model conservation standards.

4.0 The Model Conservation Standard for Utility Conservation Programs for New Commercial Buildings

The model conservation standard for utility conservation programs for new commercial buildings is as follows: Utilities are required to implement, in accordance with the requirements detailed below, the Bonneville/utility new commercial model conservation standard program, implement an equivalent alternative program, or rely on building codes that capture all regionally cost-effective electricity savings. The Bonneville/utility new commercial model conservation standards program consists of an aggressively marketed technical and financial assistance program[10] made available by Bonneville and local utilities to commercial building developers and owners.

Financial Assistance

Financial assistance offered through the Bonneville/utility new commercial model conservation standards program should be no less than the difference in net present value between a building built to levels of efficiency that minimize the consumer's life-cycle cost and a building built with all regionally cost-effective conservation measures. The maximum financial assistance should be the regional cost-effective limit for lost-opportunity resources. Bonneville and the region's utilities should set the financial assistance at levels sufficient to achieve 85 percent of the savings that would be achieved if all new commercial buildings and all existing commercial buildings undergoing major remodels or renovations were constructed with all regionally cost-effective electricity conservation measures. Efforts to achieve the penetration

10. Energy Smart Design is the name given to the Bonneville marketing program to encourage commercial construction that captures all regionally cost-effective electricity savings.

goal of the model conservation standards for new commercial buildings should continue as long as the program remains regionally cost-effective. In evaluating the program's cost-effectiveness all costs, including utility administrative costs and financial assistance payments, should be taken into account.

Submission of Utility Plans for Compliance with the Model Conservation Standard for Commercial Programs

Utilities should submit to and have approved by Bonneville a plan declaring how they intend to meet the model conservation standard for utility conservation programs for new commercial buildings. The ultimate goal for such programs is to obtain, in combination with codes and other regional programs, at least 85 percent of the savings that would have been obtained if all new commercial buildings and all existing commercial buildings undergoing major remodels or renovations had been constructed with all regionally cost-effective electricity conservation measures.[11] The dates Bonneville sets for utility plan submission and plan implementation should reflect the urgent need to capture all regionally cost-effective, lost-opportunity savings in new and existing commercial buildings. In subsequent years, a utility may change its declaration, subject to the same Bonneville approvals required for the initial plan submission.

There are several ways utilities can comply with the model conservation standard for utility conservation programs for new commercial buildings. These are:

1. Submit to and have approved by Bonneville a declaration that a code for new commercial buildings that captures all regionally cost-effective electricity savings has been or will be adopted and enforced by a state and/or local government not later than the date specified by Bonneville,[12] and annually thereafter.

2. Submit to Bonneville a declaration agreeing to adopt and implement the Bonneville/utility new commercial model conservation standard program not later than a date specified by Bonneville.

3. Submit to and have approved by Bonneville an alternative program that will be implemented and enforced not later than a date specified by Bonneville. This alternative program should be capable of providing savings equivalent to the Bonneville/utility new commercial model conservation standard program and not duplicate acquisition of other resources that are already in the Council's plan. Alternative programs may include, but are not limited to, state or local government or utility marketing programs, financial assistance, codes that capture all the regionally cost-effective savings available from the model conservation standards for new commercial buildings, utility service standards or fees or combinations of these and/or other measures to encourage energy-efficient construction of new commercial buildings or other lost-opportunity conservation resources.

Surcharge Recommendation

The Council, pursuant to Section 4(f)(2) of the Act, recommends that a 10-percent surcharge be imposed on utilities that have not complied with the deadlines established above to submit to Bonneville: 1) a plan for implementation of the Bonneville/utility new residential and new commercial model conservation standards programs; 2) a plan for implementation of an alternative program, which is approved by Bonneville as being equivalent, as set forth above; 3) or a declaration, approved by Bonneville, that the model conservation standards for new residential and new commercial buildings will be met by building codes that capture all regionally cost-effective electricity savings. This surcharge should continue in effect until a utility has filed a plan or declaration and has obtained the necessary Bonneville approvals. Bonneville should judge whether alternative plans will be as effective as the Bonneville/utility conservation programs for new residential and new commercial buildings in contributing to the regional goal of achieving 85 percent of all regionally cost-effective electricity savings.

Exemptions

The Council finds there is no need for exemptions at this time. If Bonneville finds that hardship exists, Bonneville should assist in the implementation of the Bonneville/utility new residential and/or new commercial model conservation programs in those jurisdictions.

Minimum Performance Standard

The Council does not propose a minimum performance standard for utilities to achieve in the operation of conservation programs for new residential and commercial buildings in this plan. However, the Council remains strongly convinced that, given the value of the model

11. Eighty-five percent is the level of compliance that the Council believes is achievable.

12. State and/or local adoption of codified versions of ASHRAE/IES Standard 90.1—1989, the U.S. Department of Energy's *Energy Conservation Voluntary Performance Standard for Commercial and Multi-family High Rise Residential Buildings*, the codified versions of the model conservation standard for new commercial buildings (i.e., the Northwest Energy Code, December 1990) or an equivalent code does not satisfy the model conservation standard for utility conservation programs for new commercial buildings. These codes/standards, without additional modifications that go beyond those specified in the model conservation standard for new commercial buildings, do not capture all regionally cost-effective electricity savings.

conservation standards to the region, utilities should be responsible for working vigorously to attain the model conservation standards in their service territories. Bonneville should measure and report to the Council the performance of utilities in attaining the goals of the model conservation standards for new residential and commercial buildings.

5.0 The Model Conservation Standard for Buildings Converting to Electric Space Conditioning or Water Heating Systems

The Council's model conservation standard for residential and commercial buildings converting to electric space conditioning or water heating systems is as follows: State or local governments or utilities should take actions through codes, service standards, user fees or alternative programs or a combination thereof to achieve electric power savings from such buildings. These savings should be comparable to those that would be achieved if each building converting to electric space conditioning or electric water heating were upgraded to include all regionally cost–effective electric space heating and electric water heating conservation measures.

Financial Assistance

The Council recommends that no financial assistance be offered to consumers to offset the cost of conservation investments that are required prior to conversion to an electric space conditioning or water heating system from another energy form.

Surcharge Recommendation

The Council believes that utilities should adopt conversion standards. However, at this time the Council does not recommend that a surcharge be imposed for failure to act accordingly.

6.0 The Model Conservation Standard for Conservation Programs not Covered by Other Model Conservation Standards

This model conservation standard applies to all conservation actions except those covered by the model conservation standard for new electrically heated residential buildings, the standard for utility conservation programs for new residential buildings, the standard for all new commercial buildings, the standard for utility conservation programs for new commercial buildings and the standard for electric space conditioning and electric water heating system conversions. This model conservation standard is as follows: All conservation programs should be operated in a manner consistent with the long–term goals of the region's electrical power system. In order to achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to capture all regionally cost–effective conservation savings in a manner that does not create lost–opportunity resources. A lost–opportunity resource in a conservation measure or program is one that, due to physical or institutional characteristics, will lose its cost–effectiveness unless actions are taken now to develop it or hold it for future use. Installing only the easiest and least–expensive conservation measures (referred to as "cream skimming"), for example, often can mean that it is no longer cost–effective to return to install added measures.

2. Conservation acquisition programs should be designed to secure all measures in the most cost–effective manner possible. Expenditures for acquiring conservation resources should recognize that administrative costs and incentive payments must be balanced to achieve the lowest overall cost for the resource. Under some circumstances, for example, it may be more cost–effective to pay for all of the conservation measures than to incur the administrative costs associated with partial payments.

3. Conservation acquisition programs should acknowledge that for certain measures there is a limited "window of opportunity" during which all of the conservation potential should be secured. In some cases, this will mean matching the conservation acquisitions to the schedule of the host facilities. In industrial plants, for example, retrofit activities should match the plant's scheduled downtime; in the commercial sector, measures should be installed at the time of renovation or remodel; and in all sectors, energy code revisions should incorporate all regionally cost–effective measures.

4. Conservation acquisition programs should be designed to ensure that regionally cost–effective levels of efficiency are economically feasible for the consumer. Economic feasibility is defined as that level of conservation investment that results in lowest life–cycle cost to the consumer. Conservation investments beyond that point, which result in electricity savings that are cost–effective for the region, should be paid for by the region's utilities.

5. Conservation acquisition programs should be designed so that their benefits are distributed equitably throughout the region. If the program is operated on less than a regional level, its benefits should be distributed equitably throughout its target market area.

6. Conservation acquisition programs should be designed to maintain or enhance environmental quality. Acqui-

sition of conservation measures that result in environmental degradation should be avoided or minimized.

7. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve. Acquisition programs should undergo both process and impact evaluations. These evaluations should provide reliable information that can be used to verify program costs and savings and to improve future programs and estimates of conservation's cost and availability.

8. Conservation acquisition programs should be designed to encourage increased electrical energy efficiency and should not be used to increase the market penetration of electricity. Marketing programs, while potentially an effective means of securing conservation savings, should not attempt to influence a consumer's choice of fuel.

9. Conservation acquisitions should be given credit for characteristics that are not specifically accounted for in the Council's computation of regional cost-effectiveness. For example, because conservation actions may avoid the need for increased transmission capacity, such actions should be assigned an appropriate credit for this impact on transmission system needs.

10. Conservation acquisition efforts should not be reduced, on the ground that some consumers might otherwise have invested their own money in increased efficiency. Utility acquisition of regionally cost-effective conservation may sometimes pay for measures that some consumers would have purchased on their own. Concern for this "free-rider" potential should not keep utilities from purchasing all regionally cost-effective conservation.

Surcharge Recommendation

The Council is not at this time recommending that this model conservation standard be subject to a surcharge.

Surcharge Methodology

Section 4(f)(2) of the Northwest Power Act provides for Council recommendation of a 10 percent to 50 percent surcharge on Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards. The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives.

Bonneville's administrator is responsible for implementing the surcharge in accordance with the Council methodology for the surcharge calculation. The Council recommends that the Bonneville administrator impose surcharges as specified above. The method is set out below.

Identification of Customers Subject to Surcharge

In accordance with the schedule set forth above, the administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards for utility residential and commercial conservation programs, including meeting all filing deadlines.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is then calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

3. If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; *plus* b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

This calculation of the surcharge is designed to eliminate the possibility of surcharging a utility twice on the same load. In the calculation, the portion of a utility's exchange resource purchased from Bonneville and already surcharged under the power sales contract is subtracted from the exchange resources before establishing a surcharge on the exchange load.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

CHAPTER 13

FINANCIAL ASSUMPTIONS

Introduction

The Council's planning process involves a number of analytical steps, including estimation of quantities and costs of resources, projection of future demand for electricity under a variety of assumptions, and simulation of the operation of the regional power system to meet demands with alternative sets of resources. All of these analytical steps require that values for a number of financial variables be assumed. Consideration of these assumptions is important for two reasons. First, the values used directly influence the outcome of the analysis, and, second, the values used in the various components of analysis must be consistent.

A number of financial variables influence the Council's planning process. Like many components of the Council's analysis, the values of these variables cannot be known with absolute certainty. This chapter describes the major issues and the reasoning behind the values adopted by the Council. It also provides an explanation of terms used throughout this chapter: nominal dollars, real dollars, present value, levelized cost and discount rate. Following this explanation, two categories of variables are examined: 1) cost of capital, including the general level of prices, home mortgage rates and the cost of capital for regional resource acquisition; and 2) the social discount rate—the rate used for converting streams of regional costs to present values.

The values used in the 1991 Power Plan are summarized and compared to those of the 1986 Power Plan in Table 13-1.

Table 13-1
Financial and Economic Assumptions for 1986 and 1991 Power Plans

Variable	1986 Real	1991 Real	1991 Nominal[a]
Inflation	[b]		5%
Home Mortgages	6.2%	5%	10.3%
Resource Acquisition			
▪ Debt (investor-owned utilities)	7%	6%	11.3%
▪ Equity (investor-owned utilities)	8.5%	7.5%	12.9%
▪ Debt (public utilities)	4%	3%	8.2%
▪ Debt (Bonneville)	5%	4%	9.2%
Social Discount Rate	3%	3%	8.15%

[a] Nominal values calculated using 5-percent inflation.

[b] 1986 plan assumed 5-percent inflation.

Explanation of Terms

Nominal Dollars and Real Dollars

Inflation distorts the apparent costs of any energy resource, making it appear to cost more if it is purchased at a later time. To control for this distortion, three concepts are used. *Nominal dollars* are the actual expenditure of dollars over time and include the effects of inflation. Therefore, nominal dollars are dollars that, at the time they are spent, have no adjustments made for the amount of inflation that has affected their value over time. *Real dollars* adjust nominal expenditures to account for the effects of inflation. By correcting for the impact of inflation on a dollar's purchasing power, a real dollar represents constant purchasing power or "real" value. That is, a real dollar has the same value relative to the ability to purchase goods and services in 1995 that it had in 1990. To convert nominal dollar costs to real dollar costs, a *base year* is chosen, and all costs are converted to that year's dollars; i.e., the inflation that occurs between years is removed. Real dollars can be compared across the board, regardless of the year, because they represent equal purchasing power. The Council used a 1990 base year and a forecast inflation rate of 5 percent per year.

Present Value and Levelized Cost

Even after costs are converted to real 1990 dollars, it is difficult to compare the costs of different resources, because costs occur in different years. For instance, a hydropower project involves a large outlay at the beginning for construction, but the fuel (water) is essentially free after completion. An oil- or gas-fired combustion turbine has a low construction cost, but the fuel cost is high and may even escalate in real terms (i.e., it may get more expensive to run even after removing the effect of inflation).

Because of the various resources available in the region and the different capital and operating cost structures associated with each, two methods may be used to place resources on even footing for cost comparison. *Present value* and *levelized cost* are the methods used. Present value implies that money has a time value. That is, *when* money is spent is as important as the *amount* of money spent. A dollar is worth more today than it is a year from now because it could be invested during the year to earn a financial return. A year from now, a dollar is converted back to its present value by calculating, over the year, the interest or return foregone. Present value then allows the equal comparison of costs of energy resources by using a standard discount rate to convert all costs, no matter when they occur, back to a lump sum at the start of the plan. The uniform series of costs that has the same present value as a resource's particular non-uniform series of costs is called the resource's *levelized cost*. For instance, the lump sum amount borrowed from a bank is the present-value cost of buying a house; the mortgage payment is the levelized cost.

Values can be levelized in either real or nominal terms. A resource's lifetime is important in the calculation of a nominal levelized cost. Even assuming that the resource is replaced by the same kind of resource at the end of its lifetime, which is typically done in this kind of calculation, a nominal levelized value will vary depending on lifetime compared to a real levelized value for the same resource. These concepts are illustrated in Figures 13-1 through 13-4 and are discussed further below.

Discount Rate

The value of money over time to the Northwest ratepayer is used in calculating present values and levelized costs and is called the *discount rate*. The discount rate used for the Council's analyses was an inflation-free, real rate of 3 percent. Nominal interest rates consist of a real rate and an inflation premium. Nominal costs are converted to present values by applying a nominal discount rate of 8.15 percent. This rate combines the real discount rate of 3 percent and a 5 percent rate of inflation.

Example

The application of all these concepts to a generic generating plant is illustrated in Figures 13-1 through 13-4. This is only a numerical example, and the costs for this hypothetical generating plant do not necessarily agree with any specific plants used in the resource portfolio. The concepts are the same for all resources; only the actual costs would differ. The example plant produces 250 average megawatts and comes online in 1996. Figure 13-1 shows the *nominal* (actual) expenditures for the plant through construction and during its operation. The line labeled "Construction Cost" represents the cumulative construction costs from the start of the project in 1991 to the time it comes online in 1996. The total capital cost is $909.6 million, which includes labor and materials of $745.7 million and interest of $163.9 million. For the purpose of this example, it is assumed that these construction costs and other associated capital costs, such as income taxes and property taxes, are repaid to lenders at a uniform rate of $150.3 million a year beginning in 1996. Those annual payments are represented by the "Actual Capital Costs" line. The line labeled "Actual Operating Expenses" rises faster than the rate of inflation due to real increases in the cost of fuel. Operating expenses start at $80.8 million per year and rise to $380.5 million per year by the end of the plant's 30-year life. Again, all costs in this chart include the effects of inflation over time.

Nominal Dollar Expenditures

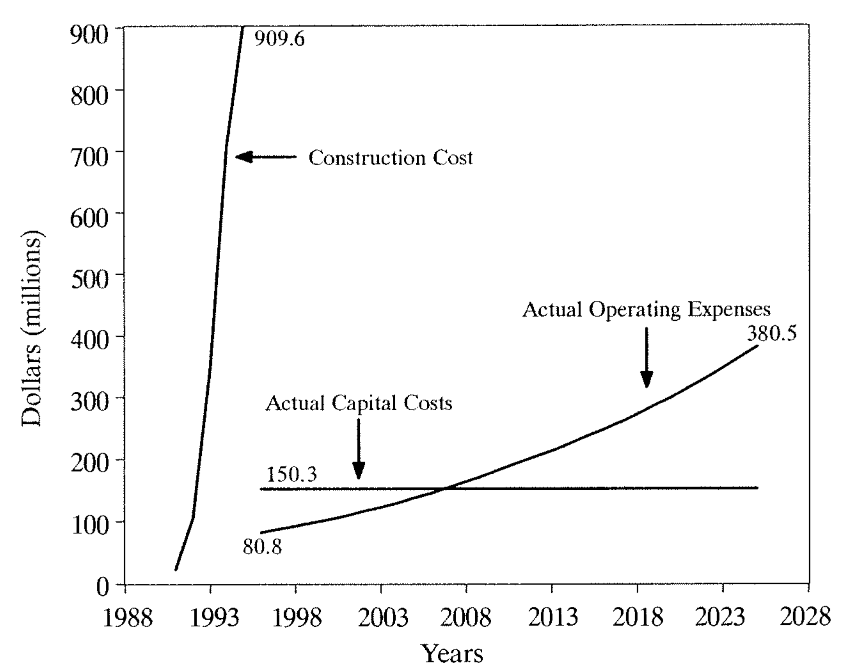


Figure 13–1
Actual Nominal Dollar Expenditures

Capital Costs

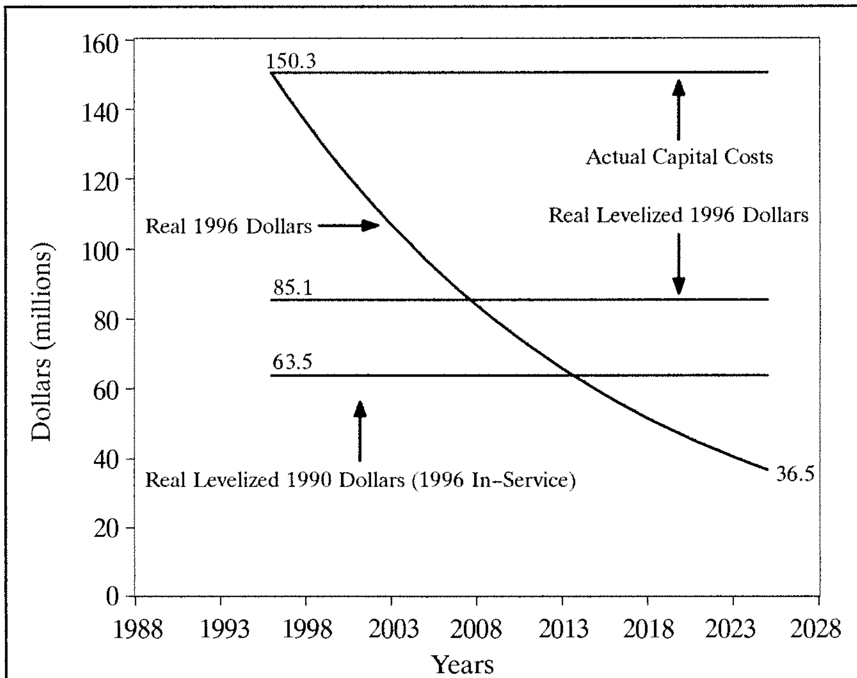


Figure 13–2
Capital Costs

Figure 13-2 takes the "Actual Capital Costs" line from Figure 13-1 and demonstrates the conversion of nominal dollars to real dollars by applying the present-value and levelized-cost concepts. The line labeled "Actual Capital Costs" represents the repayment of the construction and other capital costs from 1996 forward. Those costs remain constant despite inflation over time. By converting to real costs, hence adjusting for inflation (line labeled "Real 1996 Dollars"), the effect of inflation upon the nominal repayment costs is illustrated. Starting in 1996, capital recovery commences at a fixed payment of $150.3 million per year. Over the years, repayment is subject to general inflation, but cannot rise to reflect it. Therefore, by the end of the repayment period, the nominal repayment amount of $150.3 million is worth $36.5 million in 1996 dollars. Inflation has decreased the impact of a fixed payment, because other wages and costs have risen with inflation. The declining real costs then are annualized to levelized real costs (line labeled "Real Levelized 1996 Dollars"). This line represents the constant capital recovery payments restated to control for inflation. Finally, using the line labeled "Real Levelized 1990 Dollars," the capital recovery payments are restated to $63.5 million in base year 1990 dollars by removing inflation from 1990 to 1996. This process allows the comparison of capital costs of different resource projects by taking into account different real escalation rates during construction, while controlling for inflation and interest rates.

Figure 13-3 goes through the same process, but uses the operating expenses line from Figure 13-1 to analyze operating costs. Operating costs start at $80.8 million a year in 1996 and rise in nominal terms (line labeled "Actual Operating Expenses") to $380.5 million by the end of the plant's life. These costs rise faster than general inflation due to real escalation in the costs of fuel. If this actual stream of operating costs were converted to a constant stream that would not change from year to year, the result would be the "Nominal Levelized" line in Figure 13-3. Converting the stream of actual costs to a stream that would be constant in terms of purchasing power would yield the line labeled "Real Levelized 1996 Dollars." This line begins slightly higher, at $89.8 million, than the actual stream of costs because the costs include small real increases beyond those due just to inflation. If there were no real increases built into the actual costs, the "Real Levelized 1996 Dollars" line would begin at the same point, $80.8 million. "Real Levelized 1990 Dollars," then, takes the levelized 1996 costs back to 1990 levelized costs by controlling for inflation between those years, which gets to $67.0 million annually.

The various numbers that can describe the same plant are summarized in Table 13-2. The capital cost in nominal dollars is $909.6 million. The first-year cost, as it would actually affect rates in 1996, the first year of operation, is $231.1 million ($150.3 million plus $80.8 million) or 10.6 cents per kilowatt-hour. Converted to the base year used

Operating Costs

Figure 13-3
Operating Costs

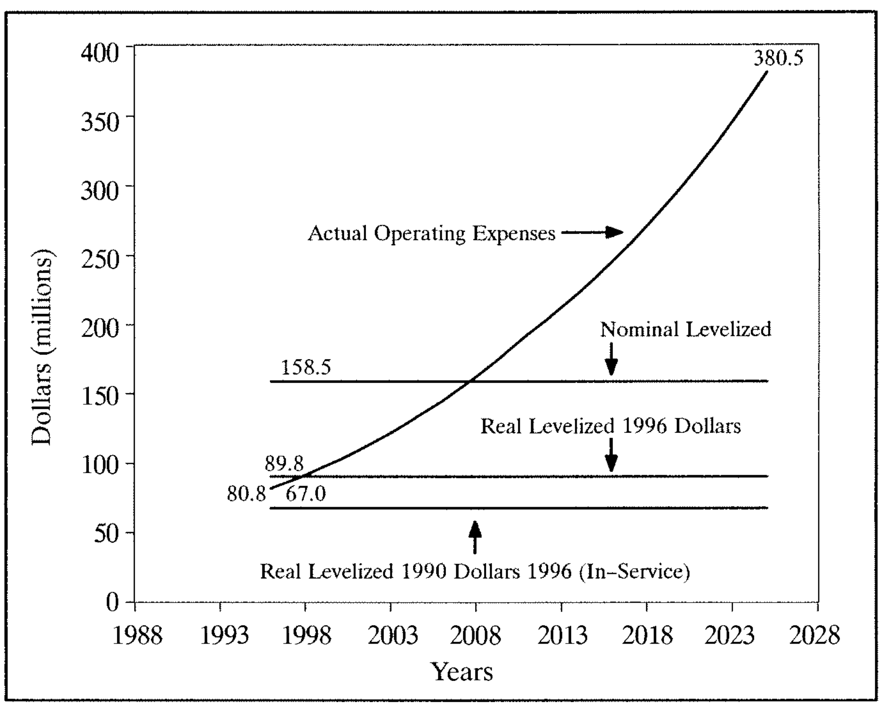


Table 13-2
Cost Analysis Summary

Total Capital Cost	$909.6 million
Direct Construction	$745.7 million
First-Year Cost (1996)	10.6 cents per kilowatt-hour
Real Levelized 1990 Dollars	6.0 cents per kilowatt-hour
Nominal Levelized	10.5 cents per kilowatt-hour

in the Council's analysis, the levelized cost is $130.5 million ($63.5 million plus $67.0 million) or 6.0 cents per kilowatt-hour. Levelized in nominal terms, it is $230.4 million or 10.5 cents per kilowatt-hour. The components of the last calculation are not shown on the graphs, but the conversion from real levelized 1990 dollars simply involves taking the present value at 3 percent and releveling at 8.15 percent. The last value, nominal levelized cost in base year (1990) dollars, is the index that is used in this plan, rather than the index used in previous Council plans, real levelized base-year dollars. It is a product of this particular example that the nominal levelized cost (10.5 cents) is almost identical to the first-year cost (10.6 cents). Generally this would not be the case. Depending on the in-service date and the mix of capital and fuel costs, the first-year cost could be substantially higher or lower than the nominal levelized cost.

Finally, Figure 13-4 illustrates the effect of lifetime on the calculation of real and nominal levelized values. A resource that has an overall real levelized cost of $130.5 million per year (6.0 cents per kilowatt-hour), such as our example resource, also could be described as having a nominal levelized cost of $230.4 million per year (10.5 cents per kilowatt-hour), if the present value were converted to annual costs using a nominal discount rate of 8.15 percent rather than the corresponding 3 percent real discount rate. These are just two different ways of expressing the cost of the same resource. A third way of expressing the cost is the rising curve in Figure 13-4, which starts at $130.5 million per year and increases at 5 percent per year (the Council's assumed rate of future inflation).

Suppose, however, that we are considering a resource with a 15-year life, which also has a real levelized cost of $130.5 million per year (6.0 cents per kilowatt-hour). How would we compare its cost to the 30-year resource that costs the same in real terms? For the sake of simplicity, we assume that the resource is replaced by the same kind of resource, which costs the same except for the 15 years of inflation between the installation of the first resource and the second. Now the two cases are comparable: a 30-year resource and two 15-year resources. The real levelized cost of each of these three resources is the same, that is, $130.5 million (6.0 cents) in 1990 base year dollars.

However, the nominal levelized costs of the three are all different. The nominal levelized cost of the 30-year resource is $230.4 million (10.5 cents per kilowatt-hour); that of the first 15-year resource is $183.7 million (8.5 cents per kilowatt-hour); and that of the second, replacement 15-year resource is $381.9 million (17.4 cents per kilowatt-hour). This means that, even assuming replacement by an identical resource, as we did in this example, we cannot directly compare the costs of resources with different lifetimes in nominal levelized terms unless we directly include the replacement resource's costs. When nominal levelized terms are used in Volume I or in Volume II, Chapter 10, Table 10-1, they have all been appropriately adjusted to comparable 40-year lifetimes, and they are calculated as if construction or program ramp-up began in September 1990 (rounded to January 1991 in this example). That is, they are comparable to the value $230.4 million per year (10.5 cents per kilowatt-hour) in Figure 13-4.[1]

It is important to remember that the process described above is used to put resource cost estimates on a consistent basis. It is not a prediction of the impact of any given resource on consumer rates in a given year. In fact, the two example resources mentioned earlier (the hydropower plant and the combustion turbine) could have quite different effects on rates in any given year. The hydropower plant is the most expensive in the first year. Because the capital cost is fixed, its real cost declines through time as other costs and wages rise with inflation. Grand Coulee Dam, for example, was a very expensive project when it was finished in the early 1940s. It is only the succeeding 50 years of inflation that have made the cost of about 0.2 cent per kilowatt-hour relatively cheap compared to the cost of new power plants.

A combustion turbine, on the other hand, has a large percentage of its total cost in its fuel cost. If operated at reasonable levels of annual output, its total cost (capital plus fuel) could be lower in the first years of its operation than the hydropower plant. However, its fuel cost will continue to rise with inflation, if not faster, and its relative

1. Nominal levelized costs in the tables in Volume II, Chapter 8, are calculated on a slightly different basis, however. These numbers assume a common in-service date, January 1990, with an assumed construction start earlier, rather than the common start date of September 1990, for all resources and in-service dates that vary as a function of lead times.

rate impact will be much higher 20 years from now than would that of a hydropower plant built now. A resource, such as the hydropower plant, could have the lowest present-value and levelized cost although it has the highest first-year cost. The Council's resource choices were not based on the rate impacts in any given year but on the present-value cost, taking into account the costs and their timing over the life of the resources.

Simple levelized cost numbers, based only on capital and operating costs, are appropriate for rough comparison of resources. For the final analysis, the resources' operating characteristics were simulated in the Council's decision analysis model, the Integrated System for the Analysis of Acquisitions (ISAAC), and the costs from that simulation were converted to present values. This is a very important distinction, because simple levelized costs usually do not take into account the changes in system operations that will result when resources with different operating characteristics are added. The system models that the Council uses for evaluating the present-value system cost of each resource added to the Northwest's existing system provide the best test of the cost-effectiveness of each resource. Adjustment factors that can be applied to simple levelized costs to approximate the results from the Council's system model are discussed in Volume II, Chapter 14, "Resource Cost-Effectiveness."

Cost of Capital

Inflation

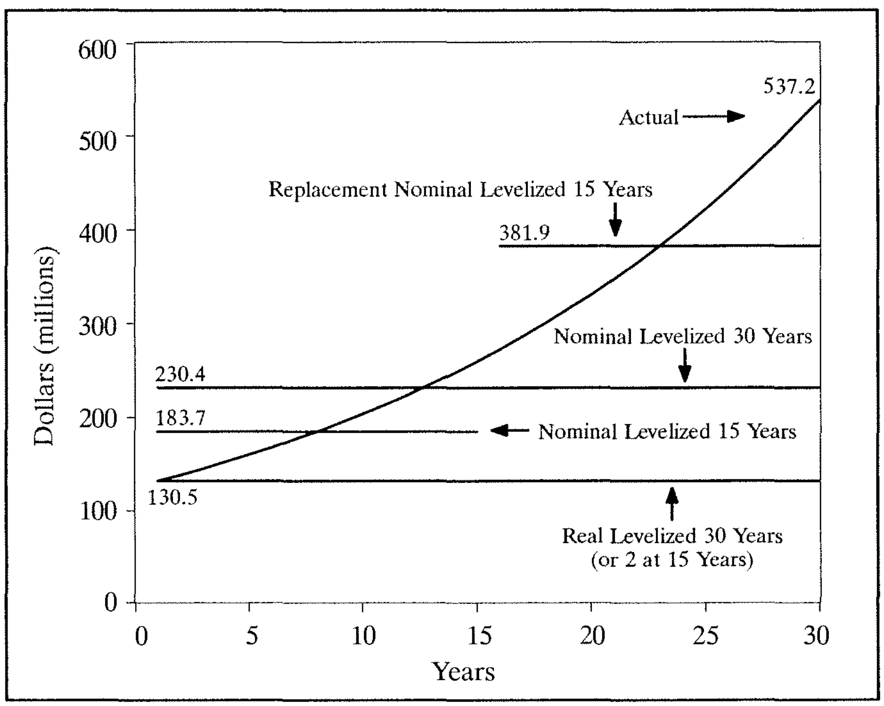
The rate of inflation affects all components of the Council's analytical process. It is impossible to project the effect of changes in costs without considering the changes from both the real and nominal perspective. For example, prices of electricity are determined in part by historical (nominal) construction costs, but projection of demand usually is based on the inflation-corrected (real) path of electricity prices. The necessary translation between real and nominal values requires a set of assumptions regarding the rate of inflation. The 1991 Power Plan uses an average inflation rate of 5 percent.

Home Mortgages

One of the most intensively analyzed resources for future electricity conservation is improved thermal efficiency in new homes. The cost of this improved efficiency, both to the individual homeowner and to the region, is influenced by the extra construction cost due to energy-efficiency measures. These increased costs are mortgaged, and therefore the present value cost is a function of the interest rate charged on the mortgage. Mortgage rates, as

Lifetime Effect

Figure 13–4
Levelizing—Effect of Lifetime



projected by the WEFA Group,[2] change over time as the overall state of the national economy changes. Because these rates influence the costs of thermal efficiency, the use of varying mortgage rates would result in varying levels of optimal thermal efficiency. From a practical perspective, this would complicate the planning process prohibitively, so the choice of a single mortgage rate assumption that is a reasonable long-run average seems more appropriate. The Council used a 5-percent real rate or 10.3 percent nominal for the mortgage rate assumption. This rate compares with the 6.2 percent real assumption used in the 1986 plan.

Resource Acquisitions by Bonneville

The cost of capital for resources acquired by Bonneville for the region should reflect the actual regional cost of capital for the companies or organizations expected to develop the resources. The region's cost of capital is reduced by any federal tax benefits accruing to the owner of the resource, but includes any risk premium that the financial markets can be expected to attach to the investment. The assumptions for the real cost of capital in the 1986 plan, based on suggestions by the region's utilities, were 7 percent for debt financed by investor-owned utilities, 8.5 percent for equity of investor-owned utilities, 4 percent for debt financed by publicly owned utilities and 5 percent for Bonneville borrowing. Based on the analysis below and comments by the utilities and others, these assumptions now appear high. Therefore, the Council adopted lower values of 6 percent, 7.5 percent, 3 percent and 4 percent, respectively, for these real costs of capital.

Ownership and Capital Structure

The net financial cost of resources is a function of who owns them and what capital structure is used. In the 1986 plan, the Council assumed that, with Bonneville acquisition available under the Act, generating projects would be financed by investor-owned utilities, using a capital structure of 80-percent debt and 20-percent equity. In this plan, the Council recognized that independent resource development has become a more likely scenario, and used more-typical capital structures of 50-percent debt and 50-percent equity for the investor-owned utilities. Bonneville and generating public utility acquisitions are financed at 100-percent debt.

Conservation also was evaluated using utility financing. Forty percent of the conservation was assumed to occur in public utility service territories and assumed to be financed by Bonneville. The remaining 60 percent in the investor-owned utility service territories was assumed to be financed by the investor-owned utilities at their normal ratio of 50-percent debt and 50-percent equity.

Representative financial characteristics for non-utility project developers also were assessed for this plan. For the portfolio analysis using ISAAC, all projects were assumed to be developed by utilities so as not to bias results by an arbitrary choice of sponsor financing. The characteristics for these three major types of sponsors are summarized in Table 13-3.

Detailed Interest Rate Analysis

Interest rates, including mortgage rates, as projected by the WEFA Group, change over time as the overall state of the national economy changes. Because mortgage rates influence the costs of thermal efficiency, the use of time-varying rates would result in varying levels of optimal thermal efficiency (and model conservation standards). From a practical perspective, this would be

2. The WEFA Group develops the national economic forecasts the Council uses in its planning process.

Table 13-3
Representative Financial Characteristics for Project Developers

	Consumer-Owned Utility	Investor-Owned Utility	Independent (Non-Utility Developer)
Cost of Equity (% nominal)	N/A	12.9%	20%
Cost of Debt (% nominal)	9.2%	11.3%	11.3%
Debt/Equity Ratio	100/0	50/50	80/20
Insurance (%/yr.)	0.25%	0.25%	0.25%
Federal Income Tax Rate (%)	0%	34%	34%
State Income Tax Rate (%)	0%	3.7%	3.7%
Gross Revenue Tax Rate (%)	2.2%	2.1%	2.1%
Property Tax Rate (%)	0%	1.4%	1.4%

prohibitively complicated, so the choice of a single mortgage rate assumption which is a reasonable long-run average seems more appropriate. Similar considerations apply to utility-financed resources.

The Council's analysis proceeded by looking at real interest rate spreads—the differences in rate due to the differences in risk or taxation borne by the lender. One of these is the premium that can be expected to be paid by Bonneville and the federal treasury, compared to the rate paid by a publicly owned utility (municipal borrowing). This is due to federal taxation of treasury interest payments, while interest from most municipal borrowing is exempt from federal taxation. Investor-owned utility bonds and home mortgages typically include a premium over treasury bonds due to the increased default risk they represent. Finally, investor-owned utility equity or common stock represents a further risk compared to the same utility's bonds because of the former's lower priority for available net revenue.

Each of the spreads is then added to an estimate of a long-term real municipal bond rate. The two most recent WEFA Group forecasts at the date of the Council's decision (mid-1989) suggest long-term real rates of about 2 and 3 percent, respectively. The Council chose to use 3 percent real for this variable.

Because the objective was to arrive at a consistent set of interest rates, the Council looked at recent historical relationships. The WEFA Group's data on 10-year treasury bonds, BAA utility bonds, 20-year municipal bonds and conventional new-home mortgage rates, over the period 1983 through 1987 (the most recent five-year period then available), are shown in Table 13-4. This period exhibits stable observed inflation rates, unlike the preceding five-year period. This table, like the following ones, will round the spreads to the nearest whole percent. It is not clear that the additional precision that could be gained in some cases would make the estimates better. In other cases, the estimates from the various data sources preclude a more precise estimate.

The BAA-rated utility bonds are one grade below those of most of the region's investor-owned utilities, which carry an A rating. The Treasury rates will be slightly low for Bonneville, which borrows at about 0.4 percent above the Treasury's 15-year bond rate, which in turn will have a slight term premium over the 10-year rate in the data. Additionally, the municipal bond data represents 20-year general obligation bonds. The longer-term revenue bonds used to finance utility investments typically would require a premium, probably on the order of 0.2 to 0.3 percent. These considerations imply that the mortgage-treasury and utility-treasury spreads might be slightly too big, but the treasury-municipal spread may still be about right. The rounded values take these considerations into account.

Table 13–4
1983 through 1987 Spread Between Real Interest Rates

	Data (%)	Rounded Value (%)
BAA Utility—Mortgage	1.17%	1%
Mortgage—Treasury	1.15%	2%
BAA Utility—Treasury	2.32%	2%
Treasury—Municipal	1.27%	1%

Table 13–5
1988 through 2007 Spread Between Real Interest Rates

	Data (%)	Rounded Value (%)
BAA Utility—Mortgage	0.67%	1%
Mortgage—Treasury	1.81%	2%
BAA Utility—Treasury	2.48%	—
BAA—A Utility	0.35%	—
A Utility—Treasury	2.13%	2%
Treasury—Municipal	1.29%	1%

The long-term WEFA Group forecast (August 1987), shown in Table 13-5, projected the following 20-year average yield spreads (1988 through 2007) for the same rates as described for Table 13-4, plus the spread between BAA and A rated utilities. The rounded estimate for the mortgage-treasury spread in this case conflicts with that based on 1983 through 1987 data; the Council relied on the historical data rather than the forecast.

The cost of equity has been taken from the Federal Energy Regulatory Commission's benchmark return on equity determinations. The mid-1989 nominal value is 12.38 percent. Assuming 5-percent inflation, this equals a real rate of 7 percent, approximately 1.5 percent above the then-current BAA bond rate, estimated at 10.8 percent nominal. Representatives from investor-owned utilities suggested that this value was somewhat low, so the Council chose a value of 7.5 percent in real terms.

Social Discount Rate

A central feature of the Council's consideration of alternative strategies for providing adequate electricity to the region is the comparison of the strategies' costs. This step is not possible unless each strategy's stream of costs is translated into a present value that can be compared to those of the other strategies. In order to accomplish this translation, it is necessary to use a discount rate that represents society's willingness to exchange consumption now for consumption in the future. For example, if the region is indifferent to choosing between $1.00 of consumption now and $1.05 a year from now, the region's rate of time preference, or its "social discount rate," is 5 percent.

In general, the lower the social discount rate, the more weight is given to the future in planning decisions. Using a higher social discount rate results in lower present values of future costs and benefits; whereas using a lower social discount rate results in higher present values. Low social discount rates tend to favor resources with high fractions of capital costs, while high social discount rates tend to favor resources with high fractions of fuel and operation and maintenance costs.

While the concept of the social discount rate is fairly straightforward, its application is more complicated. The principal difficulty is in moving from the general concept of the social discount rate to a specific number to be used in quantitative analysis. It is possible to imagine a hypothetical economy, with no income taxes, perfect knowledge (no risk), no inflation and perfect capital markets. In such an economy, individuals save and invest until the rate of return on the last investment is equal to the last investor's rate of time preference. Capital markets would enable people to adjust their consumption and investment behavior so that, while some of them would be net borrowers and some net investors, they would all attach the same relative values to consumption now and consumption a year from now (i.e., they would have the same rate of time preference).

This rate of time preference, shared by all individuals in the society, would be the social discount rate. In this hypothetical economy, the social discount rate would equal the market rate of interest, which also would equal the rate of return to the marginal investment. Thus, while the social discount rate could not be observed directly, its level could be determined by its equality with the easily observable market rate of interest.

The real world, of course, departs from the hypothetical economy described above in every respect. For example:

Taxes

In the real world, corporations and individuals pay income taxes. This means that when a consumer postpones current consumption to invest, part of the return to the investment will go to pay income taxes. Therefore, the future consumption that the investment makes possible is less than that implied by the (pre-tax) return. As a result, individuals investing in a project with a 10-percent rate of return are not demonstrating a rate of time preference of 10 percent, but rather a somewhat lower rate.

A corporation's investment behavior will be even further removed from individuals' rates of time preference. The (pre-tax) rate of return to corporate investments will have to be sufficient to cover the corporation's tax obligation, *plus* the tax obligations of the individuals who provide the corporations' capital, *plus* those individuals' rates of time preference.

Risk

In the real world, knowledge is imperfect, and investments are risky. This riskiness varies from one investment to another and is reflected in varying costs of capital from one investment to another. Generally, the riskier the investment, the higher the cost of capital to finance it. Ordinarily, the rate of time preference is understood to be the willingness to trade (certain) consumption now for (certain) consumption in the future. The Council is faced, then, with the task of estimating how much of observed rates of return are risk premiums and how much risk premium should be included in the regional social discount rate for use in the Council's evaluation process.

Access to Capital

In the real world, individuals (and organizations) are different. Individuals will demonstrate different investing and borrowing behavior. This will be due in part to differences in their income levels and their access to investment opportunities. Corporations, too, will show varied behavior, for many of the same reasons. Choosing an appropriate social discount rate for the region is equivalent to choosing an individual (or company) whose behavior is representative of the region.

Inflation

In the real world, inflation complicates the interpretation of observed costs of capital in terms of the social discount rate. Investors can be expected to insist on a rate of return that, in addition to covering their rate of time preference, tax obligation and risk premium, also will cover the expected rate of inflation. Thus, observable (nominal) costs of capital, even after income taxes and risk premiums are taken into account, will be greater than investors' rates of time preference by the amount of inflation they expect. Attempts to estimate the magnitude of inflation's effect on the cost of capital are complicated by the fact that although the inflation rate that the economy actually experiences can be measured, the inflation rate that investors *expect* cannot.

For reasons such as these, the estimation of an appropriate social discount rate from first principles is fairly complicated. A typical approach might begin with some estimate of typical return on investment in a given industry, translated to an after-tax return to the company based on some assumed corporate income tax rate for a representative company. The after-tax return to the stockholders of the representative company will be further reduced by their individual income tax rates. This rate of return would be translated to real terms by some estimate of expected inflation. Finally, the risk premium appropriate for the Council's planning process would be evaluated and compared to the risk premium included in the analyzed industry's cost of capital, and the appropriate adjustment made to arrive at the final estimate of the social discount rate.

Each step in this process requires judgments (e.g., how risky are the investments examined, should any year's data be excluded, what is a representative company, how is expected inflation related to historical inflation, etc.) that affect the results of the process. As a result, even if two analysts agreed completely on the process to be followed in extracting a social discount rate from a given body of data, they could reasonably arrive at significantly different final results.

Corporate versus Individual Perspective

An example will show how the various factors described above can cause a dramatic difference between the return to a private firm and the ultimate rate of time preference revealed by the acceptable return to the firm's stockholders.

The example starts with an assumed 20-percent hurdle rate of return on equity for investment by the private firm. The hurdle rate is a standard that is used by a firm to evaluate potential investments. If the firm has sufficient capital to invest in all the opportunities available to it, the hurdle rate ought to be the cost of capital (debt and equity) to the firm, so that it makes all the investments that pay back at least its cost of borrowing money from lenders and investors. If the firm is capital constrained, it may set a higher hurdle rate so that only the most profitable investments are chosen. The assumed 20-percent return on equity is reasonable for the private sector.

Assume the firm actually earns its 20-percent, although in practice it may earn more or less. First, it must pay federal income taxes. At a corporate rate of 34 percent, the firm pays 6.8 percent of its return to the federal government, leaving 13.2 percent for its stockholders. The stockholders also must pay individual income taxes. Assuming there is no state or local income tax, and a federal marginal rate of 28 percent, the stockholder sends 3.7 percent of the return to Washington, D.C., leaving 9.5 percent. Assuming an inflation rate of 5 percent, the stockholder's real return is 4.3 percent of the original 20 percent.

So far, the example has dealt with the equity return from a single firm. This return embodies a certain amount of business and financial risk, which raises it above a less risky return. The risk of investing in a single firm can be diversified away by investing in a number of different firms. This example will simply assume that risk is negligible, although in practice it is not. There remain the separate financial risk premiums for 1) investing in stock compared to corporate bonds that have a prior claim on the firm's net revenue, and 2) investing in corporate bonds compared to federal government bonds, which have virtually no default risk. Long-term historical data[3] suggests that the after-tax (at 28 percent) real risk premium for investing in diversified stocks compared to long-term federal government bonds is about 4 percent. This suggests that a risk-adjusted, after-tax real return for our example would be about 0.3 percent. The appropriate risk adjustment is difficult to determine and will be discussed below.

This is an artificial example, constructed to illustrate the relationships among the various measures of rates of return, but it is reasonably representative of long-term experience. The same long-term historical data referred to above suggests that the long-term return on diversified common stocks was 8.9 percent to stockholders over a period when the long-term inflation was only 2.5 percent. This return, together with a current tax rate of 28 percent, implies a long-term real after-tax return of 3.8 percent, close to the 4.3 percent of our example.

All of these factors for the example are summarized in Figure 13-5. The amount of the risk adjustment is left uncertain. Figure 13-5 also shows a similar breakdown of the rate of return for long-term Treasury bonds, assumed to be equal to Bonneville's cost of capital. Treatment of utilities' costs of capital appears later in this chapter.

3. Ibbotson, Roger and Sinquefield, Rex. *Stocks, Bonds, Bills and Inflation: Historical Returns (1926-1978).* Charlottesville: Financial Analysts Research Foundation, 1979.

Social Discount Rate

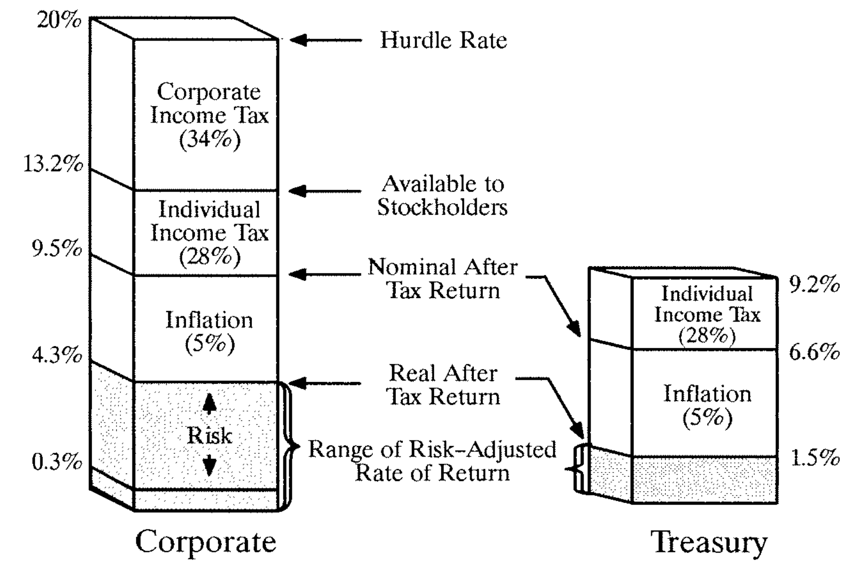


Figure 13-5
Perspectives on Social Discount Rate

Figure 13-5 demonstrates that a given investment can imply widely varying rates of return, depending on the perspective adopted. Many disagreements about the appropriate choice of social discount rate actually are disagreements about the appropriate perspective to adopt. Several perspectives have been advocated:

Office of Management and Budget

In our example, with inflation of 5 percent, the real return is 14.3 percent. The Office of Management and Budget (OMB) ruled in 1972 that the federal government should use a discount rate of 10 percent in real terms, because that was approximately the observed real rate of return in the private sector. Because it is not clear from the OMB document whether it was looking at return on equity or return on total capital, which would include some percentage of debt at lower cost, it would probably be conservative to assume the latter. This would imply that the 14.3 percent pre-tax real return on equity of the example is equivalent to the 10 percent pre-tax real return on capital of OMB.

The OMB argument is that using any lower rate for the government would simply divert capital and other resources from more productive to less productive uses. This argument does not take the perspective of the individual's rate of time preference. Rather, it looks at the effects of investment by the government and the private sector and attempts to keep them balanced in their level of productivity.

Moreover, the OMB criterion could generally be expected to be applied to investment decisions where benefits are calculated, but repayment of government costs was not expected. In addition, it could be expected to be applied to government decisions that were discretionary. Both of these conditions are different from those facing the Council, because repayment of costs of capital at market rates by customers is assumed, and spending is not discretionary if load is to be met.

Utility Perspective

Some have argued that the appropriate discount rate is the utility cost of capital, perhaps adjusted for the tax deductibility of bond interest payments. Assuming the values in this chapter for nominal costs of capital for investor-owned utilities, Bonneville and public agencies, the Council can do a calculation similar to that above as an example. With a capital structure of half debt and half equity, the weighted cost of capital for an investor-owned utility is 12.1 percent. In real terms, this is 6.8 percent. The after-tax return to an investor (in both bonds and stocks) is calculated somewhat differently than in the example, because the allowed return is after corporate income taxes rather than before. Adjusting only for the individual federal income tax and inflation, the investor's real after-tax return is 3.5 percent.

For Bonneville, as well, only the individual federal income tax and inflation are applicable, and the 9.2 percent cost of capital yields 1.5 percent to the investor (see Figure 13-5). The real cost of capital to Bonneville using these values is 4 percent. For a public agency, only inflation is relevant, and the after-tax real return equals the real interest rate at 3 percent.

The argument for using the utility cost of capital for the corporate discount rate appears to be that shareholder wealth is maximized by pursuing all investments that return more than the cost of capital. Therefore, the net present value of prospective investments is evaluated using the corporate cost of capital. The application to a governmental entity is by the analogy that the most efficient use of the capital supplied is to make investment decisions using the cost of capital as the entity's discount rate. This would ensure (assuming positive net benefits) that investments earn a return at least as great as the cost of the capital making the investment.

This cost of capital has the advantage of being relatively easy to estimate. The historical values are observable, and national projections of future values are available (see the previous section of this chapter dealing with cost of capital).

Problem of Two Utilities' Resources

If the utility-cost-of-capital approach is taken, there could be conceptual difficulties. For instance, what social discount rate would the Council use to evaluate two different types of resources supplied (and financed) by two different kinds of utilities, such as a Bonneville conservation program and a combustion turbine offered for acquisition by an investor-owned utility? The costs of capital for the two resources would be substantially different, but the consumers who would use and ultimately pay for the resource might be the same people.

Individual Rate of Time Preference

There are two ways to get at the individual rate of time preference. One is that described above—to look at the actual, achievable after-tax real returns to individual investors, preferably over some long term. Historical data suggests that the return to the stock market is in the 4 to 5 percent range, and the risk adjustments can reduce that value to the 0 to 4 percent range, depending on the appropriate adjustment. In the past, the Council and Bonneville have taken this approach and estimated an appropriately risk-adjusted value at 3 percent in real terms. In this 1991 Power Plan, the Council has continued to take this approach and has adopted the same 3 percent real value.

Another approach to the question of individual rates of time preference is to attempt to look at the typical individual. The range of individual investment and borrowing behavior is quite broad. One plausible end of the range might be the person whose marginal action is attempting to pay off a credit card bill that costs 18 percent, which implies approximately a 12-percent after-tax, real rate of return when tax deductibility is completely phased out. The other plausible end of the range could be the person whose marginal action is investing in a savings account at 5 percent, yielding a -0.7 percent real after-tax return (at a 15-percent marginal tax rate).

Calculating a typical individual's rate of return would be extremely difficult, especially because individuals often appear to demonstrate multiple discount rates with this approach. For example, an individual might deposit into the savings account one month and make an extra attempt to pay off the credit card bill the next. A serious attempt to implement this approach would need to take into account other dimensions of these investment alternatives, such as liquidity, perceived risk and minimum scale of investment.

For example, Table 8-75 in the 1989 *Economic Report of the President*[4] shows total consumer credit in 1988 varying from $690 billion to $723 billion. This total, however, includes several components, such as loans for automobiles and mobile homes, whose rates of interest are significantly less than those of credit cards. The category most representative of credit cards, revolving credit, makes up about one-fourth ($162 billion to $181 billion) of the total. Moreover, it is not clear whether this amount represents the total of credit card billings (much of which is paid off each month) or the amount on which interest actually is paid, although the former seems more likely.

But individuals demonstrate their rates of time preference not only by borrowing, but also by lending and investing. Table B-68 of the *Economic Report of the President* shows that holdings in savings accounts and money market deposit accounts amounted to more than $900 billion ($400+ billion and $500+ billion, respectively) in 1988. These accounts bear interest at rates substantially below stated interest rates on credit cards, (typically, 0 percent or less, after-tax real) and therefore imply rates of time preference, which are lower as well. Furthermore, the volume of funds in these accounts is roughly five times that of revolving credit accounts.

In addition to charging things on credit cards and depositing in savings accounts, people make other decisions that suggest rates of time preference between the high levels indicated by credit cards and the low levels indicated by savings accounts. These other decisions include mortgage financing, auto financing and purchases of stocks and bonds.

This range of behavior means that it is impossible to impute a single rate of time preference to all the region's ratepayers, based on a single mode of behavior. Some individuals, no doubt, have fairly high rates of time preference, consistent with the real after-tax cost of credit card borrowing (although, as we have pointed out, those rates

4. Council of Economic Advisors. *Economic Report of the President*. Washington, D.C.: United States Government Printing Office, 1989.

of time preference are likely to be significantly lower than the stated rate of interest). Many other individuals, however, demonstrate savings and investment behavior that is evidence of much lower rates of time preference. The Council's concern was to choose a social discount rate that is appropriate for the average ratepayer. This rate would have fallen between those of the credit card borrower and the savings account saver, if the Council had adopted this approach.

Consumer Credit as Indicator of Rate of Time Preference

Finally, even credit card debt alone does not imply that the appropriate rate for the average individual is 14 to 18 percent real, for several reasons.

First, many credit cards extend what amounts to 30-60 days' free credit before charging interest. This reduces the actual interest rate, calculated on the actual time the cardholder has the use of the money, below the stated interest rate. For example, a $100 purchase may be made 1 to 30 days before it appears on the credit card billing, 31 to 60 days before interest is charged on it, and 61 to 90 days before interest is paid. A stated 18-percent interest rate applied to a loan counted as one month could actually be as low as 6 percent when applied to the actual time between purchase and payment. Because these interest rates are being interpreted as evidence of the individual's rate of time preference, the imputed rate of time preference also is reduced by taking credit cards' grace periods into account.

Second, credit card loans are unsecured and somewhat risky to the lender. The expected average rate of interest, taking account of bad debts, will be somewhat lower than the stated rate. From the perspective of the average borrower, there is some probability that he or she will not pay the debt, so the expected average rate of interest is reduced from his or her perspective also.

Accounting for Risk in the Social Discount Rate

It is worth noting that the most important use of the social discount rate in the Council's power system analysis is in the Council's decision model—the Integrated System for Analysis of Acquisitions—where planning strategies are simulated over a large number of uncertain futures. In this Council model, resources are financed at market costs of capital, which include risk premiums and taxes paid by lenders on their interest income. The social discount rate is used only to convert streams of revenue requirements to present values. Much of the uncertainty facing the region is modeled explicitly; the model simulates mistakes in timing of acquisition decisions, resources that don't perform up to expectations, and the like.

As a result, much of the cost of uncertainty is included in the expected value of revenue requirements over a large number of scenarios. The variation in revenue requirements simulated by the planning model is another means for planners to examine the impact of strategies on regional uncertainty. In this environment, the risk premium to be represented in the social discount rate is reduced below the level appropriate for an analysis of a single investment with a single projected outcome.

Discount Rates in Use

Table 13-6 includes a sample of discount rates suggested or used by various organizations. While it demonstrates a lack of perfect agreement among the sources represented, Table 13-6 also indicates a rough range of uncertainty for the social discount rate. Two of the sources, the Natural Resources Defense Council and the book *Discounting for Time and Risk in Energy Policy*,[5] describe an estimation process much like that adopted by the Council. They both analyze data on long-run (1920s to 1970s) average returns to investments of various levels of risk and estimate real after-tax returns for the lowest-risk class of investment. They both conclude that these yields have varied from -2 percent to +2 percent, depending on the historical period. Furthermore, they both conclude that 1 percent real is a reasonable estimate for a long-run average return to low- or no-risk investments. With these estimates in mind, the discount rate of 3 percent, which has been used by the Council and Bonneville for power system analysis in the past, implies that the riskiness of power system investments justifies a 2-percent risk premium in their evaluation.

Sensitivity of Resource Portfolio to Social Discount Rate

Figure 13-6 shows some of the effects on the Council's resource portfolio of using a higher or a lower discount rate. Figure 13-6 compares the relative present value of two resources. The first resource labeled "capital" in the figure has a moderately high but constant stream of costs, corresponding, for instance, to the bond repayment on a conservation program or a hydro plant, which have virtually no operating costs. The second resource, labeled "fuel," has a stream of costs that start out lower than that of the first resource, but are substantially higher at the end of its life because of inflation and real escalation. This would correspond to, for instance, a combustion turbine. The example was constructed so the present values of the costs of these two resources were equal at the 3 percent real discount rate adopted by the Council.

5. Lind, Robert C., and others. *Discounting for Time and Risk in Energy Policy.* Washington, D.C.: Resources for the Future, 1982.

Table 13–6
Discount Rates Used for Present Value by Source

Organization	Discount Rate	Type of Project
Office of Management and Budget	10% real	Federal government projects (water projects use lower discount rate)
Northwest Power Planning Council (1986 Power Plan)	3% real	Power system analysis
Bonneville Power Administration	3% real	Power system analysis
Bonneville Power Administration	4.5 to 5% real	Financial and rates analysis
Eugene Water and Electric Board (EWEB)	3% real	Power system analysis
Seattle City Light	3% real	Power system analysis
Investor–owned Utilities in Pacific Northwest	5 to 7% real	Power system analysis
Northwest Conservation Act Coalition (NCAC)	0% real	Power system analysis
Natural Resources Defense Council (NRDC)	1% real	Zero–risk social discount rate
	2 to 3% real	Costing of conservation, generating resources
Robert C. Lind, et. al., *Discounting for Time and Risk in Energy Policy*	1% real	Evaluation of investments of risk comparable to U.S. Treasury bills
	2% real	Evaluation of investments of risk comparable to long–term U.S. government bonds
	4.6% real	Evaluation of investments of risk comparable to “market portfolio” (using 20–percent tax rate)

Figure 13–6 shows that a higher discount rate reduces the present–value cost of the fuel–intensive resource relative to the capital–intensive resource. While a higher rate reduces the present value of both, it reduces one more than the other. Figure 13–6 displays only the relative change in present values. This happens because a higher discount rate puts less weight on the future, which is the period in which costs of the fuel–intensive resource are higher than the costs of the other resource. A discount rate lower than 3 percent has the opposite effect on relative costs, because it puts greater weight on the future.

Discount Rate Sensitivity

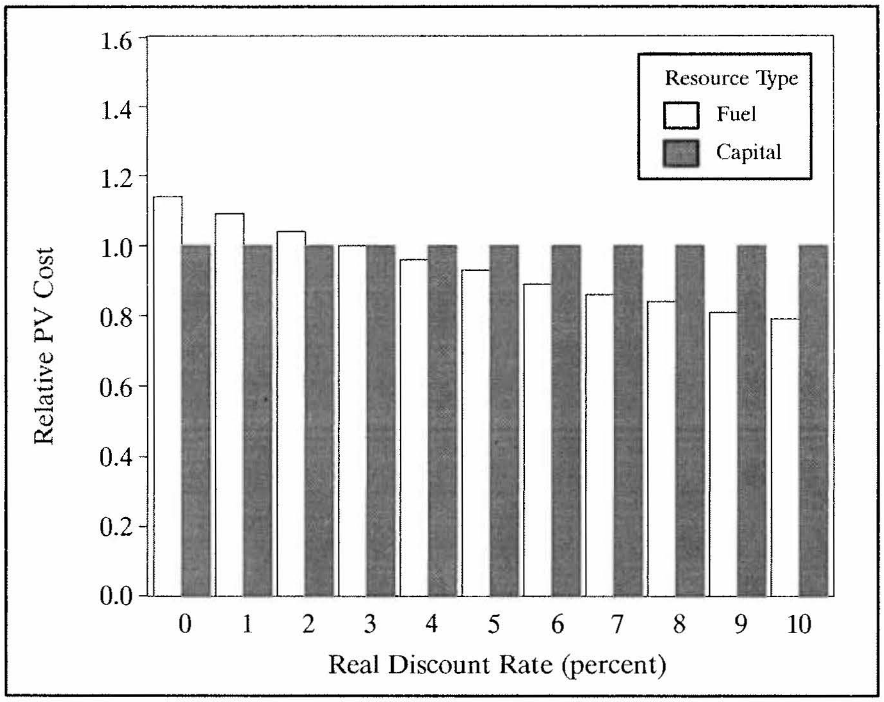


Figure 13-6
Sensitivity to Discount Rate

CHAPTER 14

RESOURCE COST-EFFECTIVENESS

Introduction

All resources included in the Council's resource portfolio are selected based on their relative cost-effectiveness. Cost-effectiveness is a measure of the relative cost of the contribution of a resource to the region's electrical power system. The Council has chosen, as the appropriate measure of cost-effectiveness, the net present value cost, including both capital and operating costs for each resource evaluated from the perspective of its operation in the entire regional power system. The Integrated System for the Analysis of Acquisitions (ISAAC) computer model was used in the evaluation. The perspective is described further in the section on resource evaluation methodology below, and the computer model is described in Volume II, Chapter 15. The Council uses an estimate of the levelized life-cycle cost of each resource as a preliminary screening tool to select resources for detailed study in the resource portfolio analysis. The calculation of resource levelized costs is described in Volume II, Chapter 13, and the costs are shown in Volume II, Chapter 10, Table 10-1.

The cost-effectiveness analysis has two primary roles in the development of the Council's resource portfolio and Action Plan. The first role is to generally size the amount of each resource that may be available in the supply curves of conservation and generating resources over the planning horizon and to rank them in order of desirability.

The second role is to select from among these resource candidates those that are cost-effective for the region to secure now. Specific near-term acquisitions are difficult to predict in advance; however, a cost-effectiveness criterion will allow the region to select only those resources that contribute the most value to the region's power system. In the following sections, each of these roles of cost-effectiveness analysis will be discussed.

Cost-Effectiveness and Supply Curves

In past plans, the Council has used coal technologies as the marginal resource, assuming that an unlimited supply of coal plants was available and that nothing, except for some conservation, due to the specific benefits under the Act, would be more expensive. This meant that all resource supply curves had been cut off at the cost of coal plants. For this plan, however, the Council has judged that coal-based technologies may be limited in total supply, just as other generating resources are limited. In the case of coal, the limiting factor is environmental concern. This limitation has meant that resources that are more expensive than coal-based plants would be acquired in the highest load growth scenarios. These resources are generally higher-cost renewables. Because of this change, the Council has chosen a higher cut-off point for the resource supply curves, including those for conservation, than in previous plans. For this plan, the Council included resources and measures up to 15 cents per kilowatt-hour in its generating resource and conservation supply curves.

Cost-Effectiveness of Acquisitions

For the evaluation of acquisitions, however, the Council has chosen other criteria for cost-effectiveness. The evaluation of the cost-effectiveness of acquisitions begins with an analysis, using ISAAC, of the value of resources to be acquired over the next several years. Figure 14-1 illustrates the different values of resources with lifetimes from zero to 50 years. The value is based on the average cost of resources displaced when a zero-cost resource is acquired in 1995. This analysis was done using the first resource portfolio described in Volume I of the plan, which is based on the Council's best estimates of future resource costs and availability. In the low-load cases, no or only low-cost resources are displaced, and a low value is calculated; in high-load cases, costly resources are displaced, and a high value is calculated. The values plotted in Figure 14-1 are the average values over 100 different load cases that were analyzed.

Figure 14-1 shows two curves, one plotting avoided costs in nominal levelized terms and one in real levelized terms. As described in Chapter 13, "Financial Assumptions," nominal levelized costs are more sensitive to a resource's lifetime. This occurs because nominal levelization incorporates future inflation in the levelized value, while real levelization does not. For resources which are otherwise identical, the longer the lifetime of the resource, the more future inflation is incorporated in the nominal values and the higher the levelized cost, compared to the corresponding real levelized cost.

The curve labeled "Nominal" in Figure 14-1 shows, for example, that a resource acquired in 1995, with an expected lifetime of 40 years, has an expected value to the region's power system of approximately 7.7 cents per kilowatt-hour. In real levelized terms, shown on the other curve, this value is approximately 3.9 cents per kilowatt-hour. The Council used these avoided cost estimates to determine the general value of resources to be acquired during the next five years.

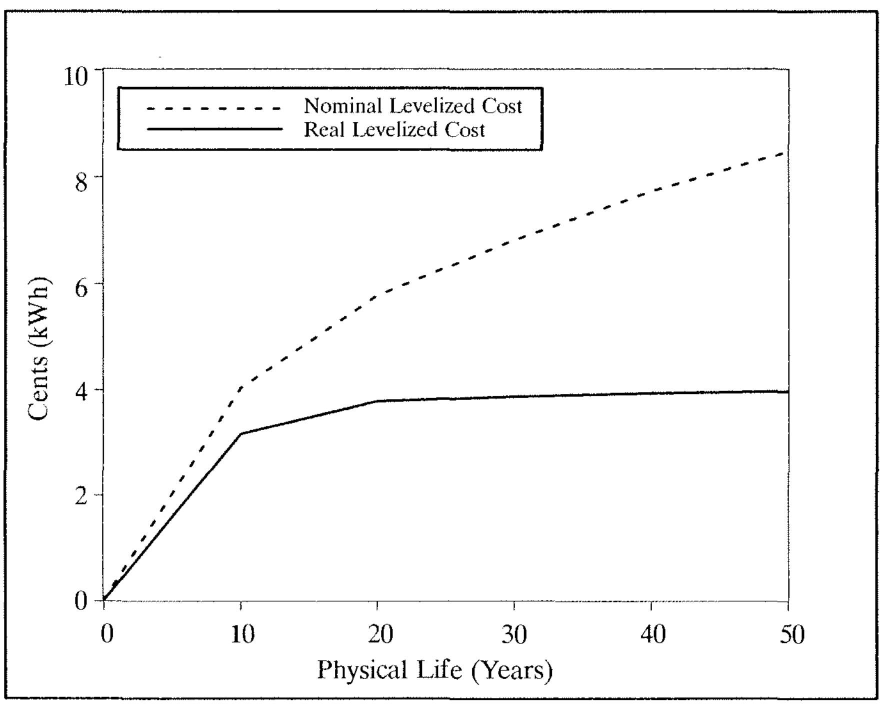
In the other nominal levelized cost estimates quoted in the plan, resource lifetimes have been normalized to 40 years by incorporating replacements, using the same technology, for those resources with lifetimes of less than 40 years. Normalization is appropriate for these uses. For example, in the case of conservation, this method estimates the cost or value of ongoing improvements in the efficiency levels of consumers' energy use. In the case of a generating technology with a life of less than 40 years, it shows a similar thing, the cost or value of an ongoing use of that technology. Normalization is not appropriate, however, in calculating the levels of payments to be made to resource developers for short-lived resources for which the developers provide no replacement resource.

Application to Conservation

For conservation resources, the avoided cost must be adjusted upwards. The conservation resources included in the portfolio, and thus in the calculation of the avoided cost, had their costs adjusted upwards by 20 percent of the direct cost to cover program administrative costs. Costs were adjusted downwards by 2.5 percent of the direct cost to account for the Council's estimate of the savings in transmission and distribution investment that occurs because conservation occurs at the end use. A further downwards adjustment of 10 percent of the direct cost was made to take account of the Act's conservation credit. Finally, the energy available from the conservation measures was adjusted upwards by 7.5 percent to account for the fact that the analysis is done at the generator bus bar. Conservation resources do not have to generate the

Avoided Costs

Figure 14-1
Regional Avoided Costs—1995 Energy



approximately 7.5 percent transmission and distribution losses in addition to the energy that reaches the end user.

In calling for acquisition of conservation measures costing up to 11 cents per kilowatt-hour (or 5.6 cents levelized in real terms), the Council recognized that marginal measures in a program should not be burdened by the 20-percent administrative cost, which is a function of the program as a whole, not of incremental measures. It further recognized that some conservation programs have seasonal patterns and the ability to track load growth closely that give them added advantages. Since weatherization programs save a percentage of the energy and capacity that would otherwise have been used, rather than fixed amounts, the savings increase as the weather becomes more severe. This factor is particularly important for capacity savings. Additionally, the Council judged that conservation had important non-quantifiable environmental benefits compared to most conventional generating resources. Finally, it recognized that the marginal measures in a conservation program may have lost-opportunity value, if they are not acquired and generating resources with higher environmental costs have to be acquired in the future instead.

The Council expects the average cost of conservation programs to be substantially lower than 11 cents per kilowatt-hour because of the inclusion of lower-cost measures as well as the higher-cost measures. The Council further recommends that utilities pay no more than is necessary to achieve the Council's recommended conservation penetration levels, while including all regionally cost-effective measures, those up to 11 cents per kilowatt-hour in their programs.

Application to Generation

For generating resources the costs in Figure 14-1 can be used directly, subject to several adjustments. To apply the regional avoided cost estimate to specific generating resources proposed by specific utilities or developers, adjustments would need to be made to take account of the individual utility's situation. The resource used to calculate the regional avoided cost had a flat seasonal shape. All specific resources proposed for acquisition will need to be adjusted for seasonal shape and load following ability. Special local situations, such as the transmission constraint the Puget Sound region faces, would call for additional credits for resources that could help mitigate the constraints. Several of these factors are described further in the following section.

Resource Evaluation Methodology

Introduction

The computer models used by the Council for this type of analysis tend to be large and complex, and the algorithms used are not widely understood. They also require significant computer resources to operate.

Outside parties, such as resource developers and regulatory agencies, have an interest in resource cost-effectiveness issues. However, the methods used by these groups for resource evaluation tend to be significantly different than those used by the Council. Such discrepancies can easily lead to different results and conclusions about resource cost-effectiveness.

The purpose of this section is to describe a method that allows outside parties to estimate resource cost-effectiveness in a manner that is consistent with the Council's methodology, but without needing access to the Council's computer models. The goal is to develop a process that can be easily applied to an individual resource. Such a process should take the important characteristics of the resource into account, and yield cost estimates similar to those of the full Council methodology. If successful, the methodology should provide a means for more consistent perspectives between the Council and other parties in evaluation of resource cost-effectiveness. It should be noted that the results presented in this section are limited in scope. Not all resource traits or possible combinations of important characteristics are addressed here.

The studies summarized in this section were not revised between the draft and final plans, and so they are still expressed in January 1988 dollars, unlike all other numbers in the final plan. The Council intends to work further with Bonneville, the utilities and other interested parties to refine these initial estimates and to reconcile them with the values used by Bonneville in its billing credits and resource bidding solicitations.

Background

Most resource developers and regulatory agencies use a "stand-alone" approach for evaluation of resources. That is, the costs of a generation project are evaluated as if that resource were operating in isolation. Assumptions are made about project operating levels, and estimated costs for capital and operating expenses are projected through time. Engineering economy techniques are used to translate these cost streams into levelized costs. The project's levelized costs then are compared to those of other projects or to avoided cost estimates for a determination of cost-effectiveness. Only the costs associated with a particular resource are considered in the analysis.

The Council's methods for determination of cost-effectiveness differ significantly from this stand-alone approach because they rely on a system perspective. The objective is to capture the cost impacts that would occur over the entire regional power system due to the addition of a new resource. When a resource is added to the system, it is likely to produce effects that extend beyond that individual project. For example, it may affect the operating levels and costs of other resources, such as combustion turbines or coal plants. It also might affect the amount of energy sold on the secondary market, impacting secondary revenues. Depending on the load/resource balance conditions, it could have an effect on the level of load served. In addition, the nature of the energy produced by an individual project can have cost or value consequences. For instance, variations in seasonal output can affect the value of the resource. The Northwest load shape and nature of the hydro system constraints combine to convey more value to projects which produce more of their energy in the fall and winter.

The Council captures these effects by modeling the entire Northwest power system as well as secondary energy markets in the Pacific Southwest and Canada. This makes it possible to simulate the way a new resource would operate in the system, and its impact on the operation of other resources, and thus estimate all changes in system costs due to that resource. By testing different resources or sets of resources, conclusions can be made about relative cost-effectiveness. Bonneville, the Pacific Northwest Utilities Conference Committee (PNUCC), and several utilities in the region use similar methods. In fact, several of the models used for regional planning were developed jointly by staff from the Council, Bonneville, the InterCompany Pool, PNUCC and the utilities. However, because of the size and complexity of the models, the user group generally is limited to the above organizations.

This gap in methodology can easily lead to differences in conclusions about resource value. It is possible for two projects which have similar stand-alone costs to have very different cost effects, when viewed from a system perspective.

In the Council's 1986 Northwest Power Plan and again in the 1989 supplement to that plan, the Council attempted to bridge this gap by publishing estimates of regional avoided costs. Avoided costs represent an amount the region could afford to pay for new resources and still have system costs equal to those obtained through the plan's resource portfolio. The intent was to provide a benchmark against which project sponsors could test levelized costs. If a project's estimated levelized costs were less than avoided costs, the resource would save the region money over the resource portfolio, and therefore would be cost-effective. However, to be directly comparable to the avoided cost estimates, the project being evaluated would need to have traits identical to those of the resources used in development of the avoided cost numbers. This would rarely be true, and therefore the avoided costs in the 1986 plan and the 1989 supplement were of limited use.

Methodology

The resource evaluation methodology consists of three steps. The first step is the calculation of project stand-alone levelized cost. The levelized cost calculation should incorporate all direct and indirect capital costs, associated finance rates, taxes, fixed and variable fuel costs, fixed and variable operating and maintenance costs, escalation rates, financial life and physical life. For comparability, the levelized costs should be expressed in real terms using a real discount rate of 3 percent (and assuming 5 percent future inflation). Costs should be expressed in January 1988 dollars. If year-to-year variation in energy output is expected, the average generation should be used in the levelizing calculation. Note that this section of Chapter 14 refers only to real levelized cost rather than nominal levelized cost. This was done to eliminate the adjustments that would be necessary due to different lives for resources that developers might propose. As was described above and in Volume II, Chapter 13, nominal levelization requires adjustment for comparable lifetimes for levelized costs to be comparable.

The second step is to apply a series of adjustments to the stand-alone levelized cost. The magnitude of adjustment is based on a set of selected resource attributes. These are characteristics of resources which would be moot in a stand-alone cost analysis, but which would have an effect in a system-oriented analysis. Depending on the nature of the attribute, the adjustment could have a positive or negative effect. The net effect of these adjustments would be to translate the stand-alone levelized costs into an estimated levelized cost from a system perspective.

The final step is to compare the adjusted levelized cost to avoided cost estimates. The adjusted costs should now be on a basis that is comparable to system avoided costs, and direct comparison would be appropriate. A conclusion of cost-effectiveness is warranted if the adjusted costs are lower than avoided costs. It implies that a full system analysis would find that the resource produces net benefits to the region. Obviously, if adjusted costs are higher than avoided costs, the resource is not cost-effective.

Important System Perspective Resource Attributes

A set of resource qualities was investigated and found to have significant effects in a system-oriented analysis. Again, these traits are limited to those that would have no effect in a stand-alone analysis. Obviously, other variables, such as capital or fuel costs, have a major effect on resource cost-effectiveness, but these are already included in both the stand-alone and system analysis and would not lead to differences in conclusions between the methods. The resource attributes addressed and found to have significant effects included:

1. seasonality,
2. ratio of firm to average resource capability,
3. discretionary versus non-discretionary scheduling, and
4. construction lead time.

The results presented here were determined through use of the Council's decision analysis modeling system, except for the results on seasonality, which were determined using the System Analysis Model. A base case was first developed for each variable. Structured changes were made to the variables, and new model runs were made to determine the change in the present value of system costs. System costs include fuel and operating costs for all generating resources, revenue from secondary sales, emergency purchase costs, and capital costs for all new generating resources and conservation programs. The present value changes in system costs were translated into levelized costs adjustments using a discount rate of 8.15 percent and a time period equal to the physical life of the resource, usually 40 years. All levelized costs and adjustments referenced in this section are in nominal terms and expressed in January 1988 dollars. A discussion of the results for each variable follows.

Seasonality

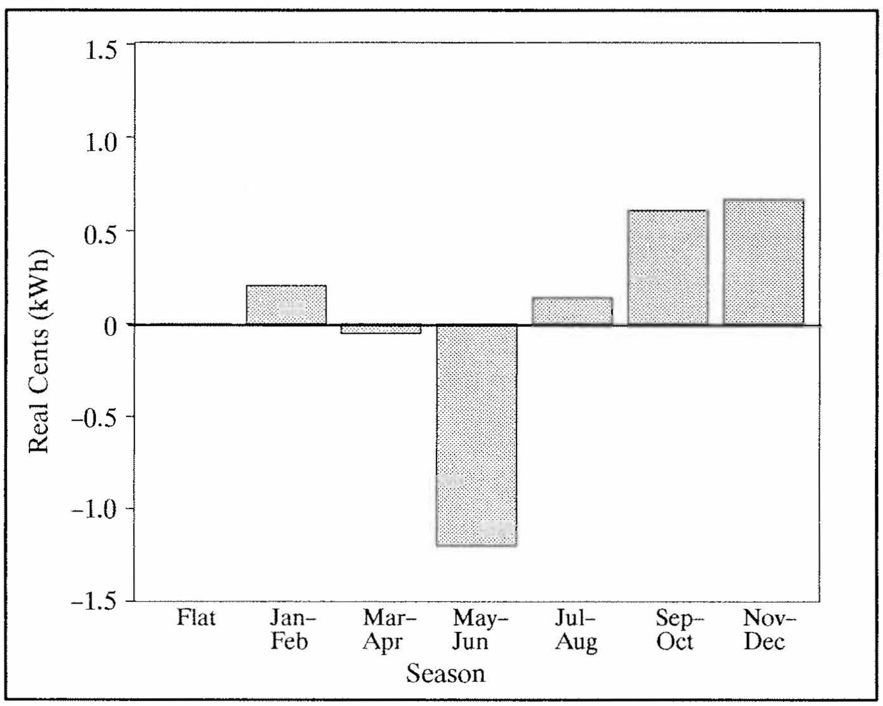
The effect of changing seasonality was studied by dividing the year up into six separate two-month periods. The periods chosen were January-February, March-April, and so forth. Seven resources were studied, six of which produced all of their energy in one of these two-month periods. The seventh resource had a flat seasonal distribution; that is, the energy output was constant across the year. The resources were identical in all characteristics except for seasonality variations.

The effects of changes in seasonality are depicted in Figure 14-2. The height of the bars reflects the increase in system cost (or reduction in value) over a project which would have a uniform or flat seasonal distribution. For instance, energy produced only in the January-February time period would be worth about 0.2 cents per kilowatt-hour more than a project which produced the same total annual energy output, but in a uniform fashion across the year. That is, the cost adjustment to the resource would be negative to account for the benefit. Energy in the May-June period only would receive a 1.2 cents per kilowatt-hour penalty. Late spring and summer is the high runoff period, and additional energy in this season is frequently of very limited value. On the other hand, energy produced in the September to December time frame results in a decrease in system cost (or increase in value) over a flat seasonal distribution. Fall and early winter is the season when combustion turbines have a higher probability of operation, because the probability of available nonfirm hydro energy is relatively low. Energy production in the fall, which displaces high variable cost combustion turbine energy, results in higher project value.

Obviously, no resource will produce 100 percent of its output in any one of these three periods. However, the relative worth of seasonal energy contributions should be similar to that shown in Figure 14-2. Calculating a weighted average using the period cost adjustment

Seasonal Shape

Figure 14-2
Effect of Seasonal Shape



weighted by the percentage of energy produced in the period should produce a reasonable estimate of the total seasonal cost adjustment. A sample calculation is included in the example.

Firm versus Average Energy Capability

Some resources will have differences between average or expected energy capability and their firm capability. For instance, a typical hydro project will not be able to generate as much energy in a poor runoff year as it could in a good water year. The region uses critical water capability as the basis for new resource development. A resource that has a reduction in capability that may be coincident with poor water conditions is of lower value than an identical resource with no reduction. Other resources would need to be developed to maintain system reliability. This additional capital expenditure is offset to a degree by reductions in system production costs or increases in secondary revenue under better water conditions, but the net effect is to increase expected system costs.

The effect of a reduction in firm capability is shown in Figure 14-3. The results are expressed as a function of the ratio of firm to average energy capability. The data points shown on the graph are model generated results. Values for the penalties range from zero cents per kilowatt-hour at a ratio of 1.0, to about 0.6 cents per kilowatt-hour at a ratio of zero.

Linear regression provides a good fit to the data and yields the following equation:

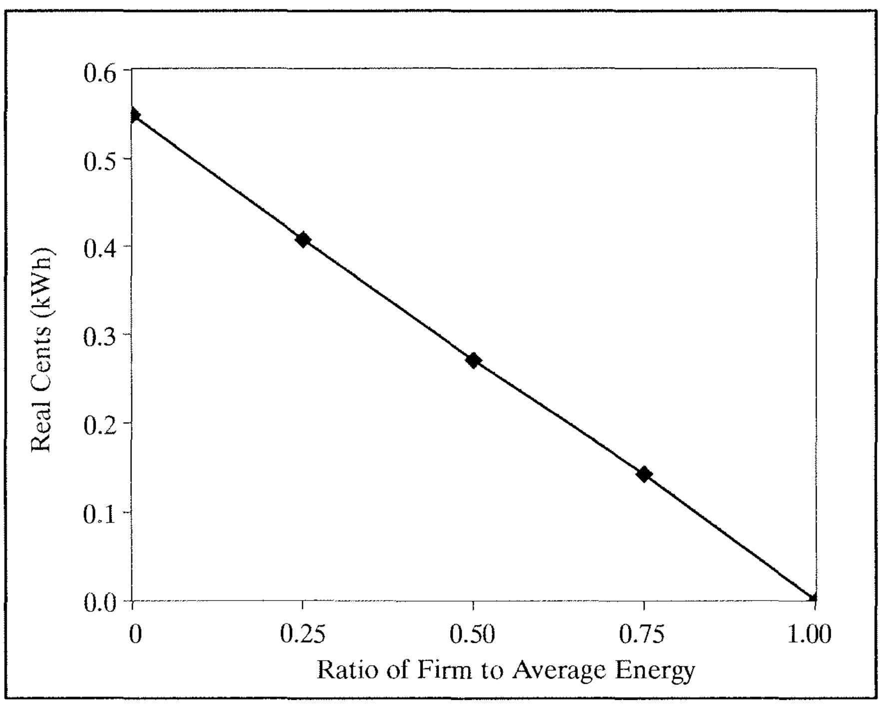
$$\text{Cost Adjustment} = 0.55 - 0.55 \times (\text{Firm Energy} \div \text{Average Energy})$$

Discretionary versus Non-Discretionary Scheduling

A discretionary resource has flexibility in scheduling. A non-discretionary resource has no flexibility in scheduling. A non-discretionary resource forces a construction decision to be made in a particular time period. It would imply a very short window during which the resource could be developed. An example might be a hydro project with a construction license about to expire, and no expectations for relicensing. If the resource is to be acquired, the decision must be made immediately. Even if the resource is cost-effective, the acquisition pattern is likely to be sub-optimal. Depending on the cost of the resource, benefits might be maximized if the resource could be developed at a later date. Forcing immediate acquisition could postpone the development of cheaper resources. The cost penalties associated with non-discretionary resources depend on the cost of the resource. Obviously, forcing a cheap resource into the system ahead of need has less penalty than forcing an expensive one.

Reduced Firm Capability

Figure 14-3
Effect of Reduced Firm Capability



The Council's methodology for calculating avoided costs uses a non-discretionary resource as its base. The objective in Council avoided cost analyses to date has been to estimate the value of lost-opportunity resources. Therefore, no additional cost adjustments are needed in cost-effectiveness determinations for a non-discretionary resource. However, rather than penalties for forced acquisition, the adjustments can be interpreted as benefits or decreases in perceived costs due to scheduling flexibility.

The effect of moving from a non-discretionary to a discretionary basis for a resource is shown in Figure 14-4. The adjustment associated with allowing the construction decision for a resource to float is expressed as a function of stand-alone levelized cost. A resource with a stand-alone levelized cost of 2.0 cents would see an adjustment due to discretionary acquisition of about -0.2 cents. Freeing up a 5-cent resource reduces its perceived system cost by about 1.2 cents. At a levelized cost of about 1.4 cents, the adjustment goes positive, indicating that to minimize system costs, the resource should be acquired immediately, regardless of need.

A linear relationship fits the data points well. The following equation can be used to calculate the adjustment for allowing discretionary decisions on a resource:

$$\text{Cost Adjustment} = 0.45 - 0.33 \times \text{Stand-Alone Levelized Cost}$$

It should be noted that the scheduling window used for this analysis was the full 20-year planning period. For shorter scheduling windows (i.e., less flexibility), the benefits will be reduced. Conceptually, there is a family of curves, related both to the cost and the scheduling window for a resource. The levels of adjustments appropriate for shorter windows have not been studied to date.

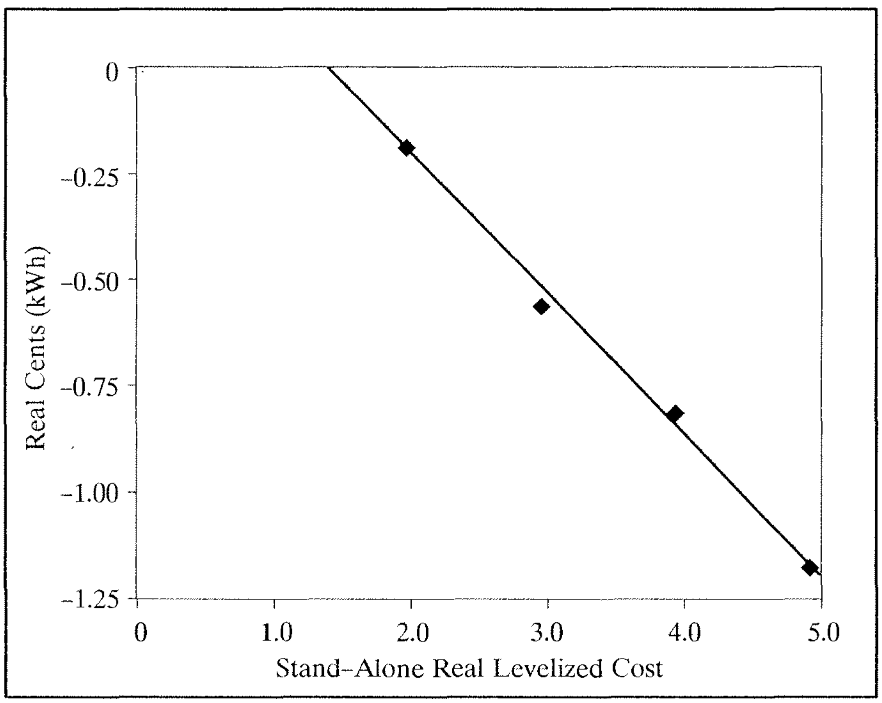
In addition, once discretionary decisions are allowed on a resource, the probability of acquisition becomes less than 1. Obviously, the more expensive the resource, the lower the likelihood of acquisition. This is the primary reason for the significant levels of adjustments seen for expensive resources. Giving the system an option on high-cost resources, without forcing acquisition, allows significant reductions in expected system cost over a forced acquisition scenario. This implies that the use of options in the resource acquisition process could provide significant system benefits.

Construction Lead Time

The effects due to construction lead are only relevant if discretionary decisions are allowed on a resource. They do not apply to forced acquisition decisions. The consequences of lead time are derived largely through load uncertainty and flexibility. Because the degree of error in forecasting loads increases with the forecast period, there is a high degree of scheduling inaccuracy for long lead time resources. This leads to systems that have a high probability of being out of load/resource balance. Missing on either side of the mark can be expensive. If there is a

Force versus Float

Figure 14-4
Effect of Force versus Float



surplus, capital will have been expended or energy produced when it is not needed. If there is a deficit, high cost emergency purchases may be needed to meet load. On the other hand, shorter lead time resources can be scheduled closer to need and can allow more efficient management of resources and capital.

The impact of lead time on resource cost is shown in Figure 14-5. These are penalties with respect to zero lead time or overnight construction. Cost penalties for lead times of one to three years are under 0.05 cents. However, after five years, penalties begin to increase rapidly, up to about 0.47 cents for a resource with a 10-year lead time.

The relationship can be estimated with the following quadratic equation:

$$\text{Adjustment} = 0.008 \times (\text{Lead Time}) + 0.0039 \times (\text{Lead Time})^2$$

Example

Table 14-1 is a simple illustration of the application of this methodology for a hypothetical small-scale hydro project.

The cost adjustment for seasonality would be calculated using the values shown in the example, as follows. Figure 14-2 shows seasonal benefits, which are weighted by the generation seasonal shapes shown above:

$$0.21(0.10) - 0.05(0.15) - 1.22(0.40) + 0.14(0.15) + 0.62(0.10) + 0.68(0.10) = -0.323 \text{ cents per kilowatt-hour}$$

The negative benefit calculated above is a cost, so it will be added to the stand-alone cost.

The cost adjustment for the ratio of firm to average output would be calculated using the equation for Figure 14-3 as:

$$0.55 - 0.55(.75) = 0.138 \text{ cents per kilowatt-hour}$$

The adjusted levelized cost would equal:

$$3.7 + 0.32 + 0.14 = 4.16 \text{ cents per kilowatt-hour}$$

Figure 14-1 showed the Council's regional avoided cost estimates. For a resource with a physical life of 40 years, the avoided cost is approximately 3.9 cents per kilowatt-hour. The project has an adjusted levelized cost that is more than avoided cost, and thus the resource would not be cost-effective.

Other Considerations

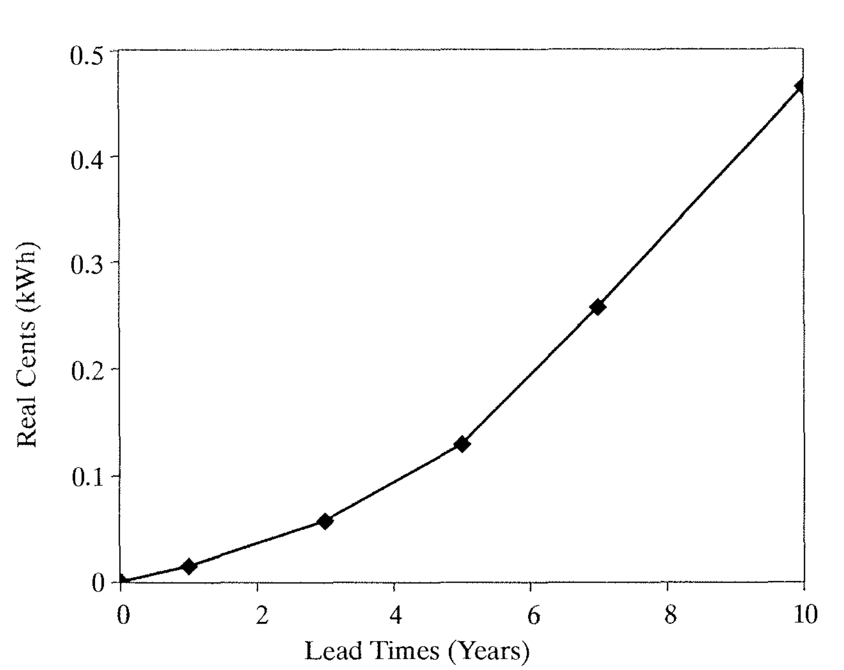
As previously mentioned, this analysis has been limited in scope. The objective was to begin to define the important variables left out of a stand-alone cost analysis and estimate their impact when viewed from a system perspective. The results are based on an assumption of independence between the variables addressed in this study. For example, the study assumed differing seasonal distributions would have no effect on the adjustments for the ratio of firm to average capability. In reality, there probably is some effect. Additionally, it was assumed that all of the impacts of physical life could be captured in the stand-alone levelized cost analysis. In reality, the magnitude of the variables addressed here will depend to some degree on physical life. Forty-year physical lives were assumed in this study.

Table 14-1
Example Data

Expected Seasonal Generation	
▪ January-February	10 percent
▪ March-April	15 percent
▪ May-June	40 percent
▪ July-August	15 percent
▪ September-October	10 percent
▪ November-December	10 percent
Ratio of Firm to Average Output	.75
Stand-Alone Levelized Costs	3.7 cents per kilowatt-hour
Physical Life	40 years

Construction Lead Time

Figure 14-5
Effect of Construction Lead Time



The target resources represented in this study are those believed most likely to be sponsored by independent power producers, with acquisition through purchase contracts. The analysis was targeted toward resources small in unit size (under 50 average megawatts) and would include primarily new hydro, cogeneration, wind and geothermal. An important assumption in this study is non-dispatchability. The resources of interest here were modeled as if both costs and energy were non-displaceable. Hence, these results would not apply to economically dispatched resources, such as combustion turbines or displaceable contracts. Additional analysis would need to be done investigating the impact of fixed/variable cost ratios at several different total cost levels to address dispatchable resources.

Intended Use

This methodology is intended to provide a means for utilities, regulators and resource developers to compare a proposed resource with other possible resources and to determine the value of the resource in serving the regional load. The methodology is based on the Council's resource portfolio and is intended to provide a regional perspective on the resource's cost-effectiveness.

The methodology is not intended to determine whether a particular resource is needed or cost-effective for an individual utility or whether the resource might be cost-effective to serve load outside the region. The perspective of each utility differs somewhat from the regional perspective. For example, avoided cost estimates are highly specific to individual utilities.

The methodology, however, also should be a useful starting point for determining the value of a resource from the perspective of a particular utility. Some adjustments described in this paper, such as seasonality adjustments, should be representative for any Northwest utility with significant hydro resources and firm combustion turbine capability. Other adjustments, such as avoided costs, can be adapted readily to reflect the unique circumstances of particular utilities.

Moreover, this methodology is not intended to give a final answer about the desirability of or need for a particular resource. The cost-effectiveness of a particular resource is an important consideration, but other factors, which are not included in this methodology, must be considered as well.

In particular, there are significant non-quantified attributes that the Council uses in making a judgment about the resources that are included in the power plan. For example, the Council considers environmental concerns, such as the effect of the resource on fish and wildlife, indoor air quality, acid rain, mining impacts, transportation, employment, etc. The Council is required by the Northwest Power Act to give a 10-percent cost advantage to conservation measures, reflecting the environmental desirability of such resources.

The Council also considers the effect of a resource on reducing future load growth uncertainty. The Council gives credit to resources that are flexible and will assist the region in adapting to the wide range of uncertainty it is facing. The Council also must decide whether sufficient valid cost and performance information is available on which to make an informed judgment.

The location of a resource also is important. Remote resources may require substantial expenditures for transmission. Resources located near large load centers may have positive effects on system stability and reliability.

Because of these additional considerations, the methodology in this section will not, by itself, give a final answer on the value to the region of a particular resource. Nor will this methodology exactly replicate the method by which the Council would evaluate a resource. It offers, however, a useful preliminary estimate of how a proposed resource compares with other resources in the resource portfolio.

Resource developers sometimes are required to determine whether a proposed resource is consistent with the Council's power plan. In the past, the only way in which to determine consistency with the Council's plan has been to request the Council to run computer simulations using its planning models. (Use of the Council's computer models for this purpose is made available at a nominal cost.) The Council's computer models will continue to be available for those seeking a more sophisticated and detailed analysis of regional cost-effectiveness.

CHAPTER 15

RISK ASSESSMENT AND DECISION ANALYSIS

Introduction

The recognition and treatment of uncertainty is one of the cornerstones of the Council's planning efforts. While all planning disciplines are subject to the effects of uncertainty, power planning is especially so. Committing to acquisition levels for conservation programs or to construction of generating resources can be multi-billion dollar decisions. Typically, these decisions have to be made with large question marks attached to some of the critical variables in power planning. With the lead times associated with conservation and generating resource development, decisions may be needed up to 10 years in advance of need. That far into the future, forecasts simply cannot be very precise for important variables, such as the level of demand, supply of resource alternatives, status of technological development, environmental factors affecting resource development, capital costs, etc.

In addition to long lead times, energy resources typically have physical or operating lifetimes of 30 to 50 years or more. Over the resource's operating life, variables such as fuel costs and output of the region's hydropower system will further affect the cost-effectiveness of resource decisions.

Nevertheless, even though the stakes are high, and information about the future is sketchy, decisions have to be made. The worst course of action would be to become paralyzed by future uncertainty and do nothing. The challenge of planning is to use the best information available, assess the benefits and risks associated with various alternatives, and take the course of action that is believed to best balance the costs and risks of energy decisions.

Incorporating uncertainty into the planning process has both quantitative and qualitative components. The analytical process tends to focus on the quantifiable issues. However, there clearly are limitations on the variables for which quantitative values and probability distributions can be defined. These typically are limited to economic and physical variables, such as fuel price forecasts or hydro condition probabilities. Qualitative variables, such as the political feasibility of particular resources or the environmental benefits and costs associated with a resource strategy, generally must be incorporated into the process through decision-maker judgment.

The objective of this chapter is to describe the computer model the Council uses for the quantitative treatment of uncertainty. This model is called ISAAC, which is an acronym for the Integrated System for Analysis of Acquisitions. ISAAC was developed jointly by staff from the Bonneville Power Administration, the Intercompany Pool and the Council, with support from the Pacific Northwest Utilities Conference Committee. It is maintained jointly by the Council and Bonneville, and is used by both organizations for resource planning studies. The rest of this chapter will provide an overview of ISAAC, discuss some of the major features within the model and briefly describe the major algorithms used in the modeling process.

Background

One of the hallmarks of the Council's plans has been the recognition and treatment of long-term load uncertainty. Ever since the first plan in 1983, the Council has characterized future demand through a range of load forecasts, and has emphasized that future load could be anywhere within that range. The forecast range acknowledges the highly uncertain nature of the assumptions underlying the forecast, and abandons the idea of point forecasting and planning resources to a specific load level with little consideration of other possible load outcomes. It recognizes the possibility of alternative futures and the large impact those futures will have on the types and amounts of resources that will be developed.

The Council's plans also have placed an emphasis on flexible, short lead time resources. Shorter lead time resources reduce the period over which the need for new resources must be forecast, and allow resource sponsors to move closer to the point of actual need before committing large amounts of capital for construction. The less lead time needed for resource development, the better that development can be matched with load. The result is that the chance for the system to be either surplus or deficit is lessened.

However, quantitative estimates of the economic value of flexibility are difficult to obtain with the analytical methods traditionally used in utility planning. Traditional planning models typically are designed to schedule or evaluate a set of future resources under one specific load condition or forecast. Loads are treated deterministically, and resource plans are formulated as if a utility has perfect knowledge of future loads, leading to systems where supply and demand are in close balance over the planning horizon. This type of study structure reflects none of the benefits inherent in short lead time resources. A study that assumes perfect information on load will show no economic difference between two resources that have the same total cost, regardless of any differences in lead time.

It is difficult to evaluate the effects of load uncertainty and their impact on cost-effectiveness with single load path models. The important effects to capture are the consequences of forecasting errors. It would be possible to manually set up studies that reflect errors in the resource planning process, resulting in systems that are out of load/resource balance. However, it would be very time consuming to set up and run enough studies to be sure of a representative set of wrong outcomes. Most of the planning studies performed before the advent of the Council were done under an assumption of perfect knowledge of future load. With single load path models, it is possible to model the single way of being right. It is virtually impossible to model all the different ways of being wrong. However, there is little doubt that the prediction of future conditions used to justify today's planning decisions will turn out to have some degree of error.

Perhaps the feature that most sets ISAAC apart from other utility planning models is its treatment of long-term load uncertainty. The model uses the entire forecast range as an input. A single study may examine hundreds of different load paths spread throughout the forecast range. The cost impacts and risks inherent in following a particular resource strategy can easily be tested across the entire load range. Because of imperfect forecasts, errors in resource planning are made, and the consequences are evaluated in terms of their magnitude and likelihood. If there are benefits associated with increasing the flexibility of a resource portfolio, they are captured and explicitly evaluated. This approach provides planners with the ability to assess the risks associated with different resource strategies and to explore alternatives to balance cost with the risk imposed by load uncertainty. This approach can provide decision-makers with information in an area where previously they had to rely largely on intuition and judgment.

ISAAC uses a modeling approach that combines features of "Monte Carlo simulation" and decision analysis. Monte Carlo simulation is a technique for exploring uncertainty by using a mathematical model of a system with uncertain elements to make repeated experiments on that system. It can be used to build quite complex models of real world systems. Decision analysis is a branch of operations research involving the evaluation of decisions in light of uncertain future events. It can provide insights into the range of consequences for a decision, and can be particularly helpful in arriving at decisions that balance the sometimes-conflicting objectives of reducing both cost and risk. This is the focus of the quantitative problem addressed with ISAAC. Given the complexities and future uncertainties surrounding the Northwest power system, what set of policies and resource actions can provide the best trade-off between cost and risk?

It should be pointed out that ISAAC is not an optimizer. It does not attempt independently to find the best resource decision or decision strategy. The decisions or strategies for resource development are user-defined inputs into the model, and the model is simply a tool to allow the evaluation of alternative actions. By comparing the results produced by one set of decisions versus another, it is possible to discern the advantages of one course of action over another.

Model Overview

An overview of ISAAC and the general modeling process is shown schematically in Figure 15-1. As discussed previously, an important set of inputs are the load forecast scenarios that define the load range and the probability distribution for that range. Other important inputs include the resource alternatives available (both conservation and generating resources), their supply distributions and constraints on rates of development, physical and economic characteristics of both new and existing resources, data characterizing the variability of the Northwest hydro system, and the nature of out-of-region energy markets. Also, instead of specifying a fixed resource schedule, the user specifies a "resource strategy" that, in general terms, defines the types of resources preferred.

The model randomly generates future load paths that in aggregate will have a probability distribution consistent with that specified in the input. It then moves through the future along one of these random load paths, forecasting and making resource decisions as consistently as possible with the resource strategy. It has very limited knowledge of the future and internally develops its own forecasts based on the characteristics of the original input load forecast range. Resource decisions are made concerning the management of individual conservation programs, preconstruction or option decisions for generating resources, and construction decisions for generating resources.

As the future within the model unfolds, random selections are made for uncertain variables. These can include such things as direct service industrial loads and loads that are not direct service, resource supply, hydro conditions, fuel prices, status of out-of-region markets and successful completion of resource options. As in the "real world," the observed values for these variables frequently turn out to be different than the predictions used when decisions were made.

Costing routines are used to keep track of the capital and production costs associated with the observed load and resource schedule, as well as secondary sales and need for purchases. Retail rates are calculated, and the load path is adjusted for price effects.

The model repeats the entire process for each year of the planning horizon. After one pass is completed, it will have simulated the effect of the resource strategy under one set of future conditions. Because of the large number of possible alternative futures, it is usually necessary to make many passes through the future to ensure statistical reliability for the results. The outcomes of all the passes are compiled into a variety of reports describing the economic and physical results for selected variables. Reports are generated that describe not only the expected value or mean outcomes, but also describe the distribution of outcomes for important variables.

The following sections describe some of the major features of ISAAC.

Multiple Planning and Dispatch Parties

To accommodate the institutional relationships and interests of the various organizations involved in electrical energy planning in the Northwest, ISAAC uses the institutional structure illustrated in Figure 15-2. There are three major categories used within ISAAC for utility organizations. The first of these is referred to as a "planning party." A planning party is defined as any utility or group of utilities for which planning activities are modeled separately. Within a study, each separate planning party can pursue its own resource strategy, independently of what others in the region do. The loads, resources and investment decisions for each planning party are tracked separately. A planning party does its own load forecasting, can have a reserved set of conservation and generating resources, and has its own priority order for resource development. One of the options available for planning parties is to place a user-defined portion of its load growth on Bonneville, through the power sales contract provisions of the Northwest Power Act. There is no limit on the number of planning parties allowed in a study. It would be possible to treat each utility in the Northwest as a separate planning party; however, the data development for such a configuration would not be trivial.

The second major organizational category is that of "dispatch party." A dispatch party is defined as a utility or group of utilities for which system operations and production costing are modeled separately. Because of the complexity of Northwest hydro-thermal operations and the system interactions of utilities, the number of dispatch parties in a study is limited to either three or four. A three-party study will have Bonneville, the aggregated generating publics and the aggregated investor-owned utilities as the three dispatch parties. A four-party study

Model Overview

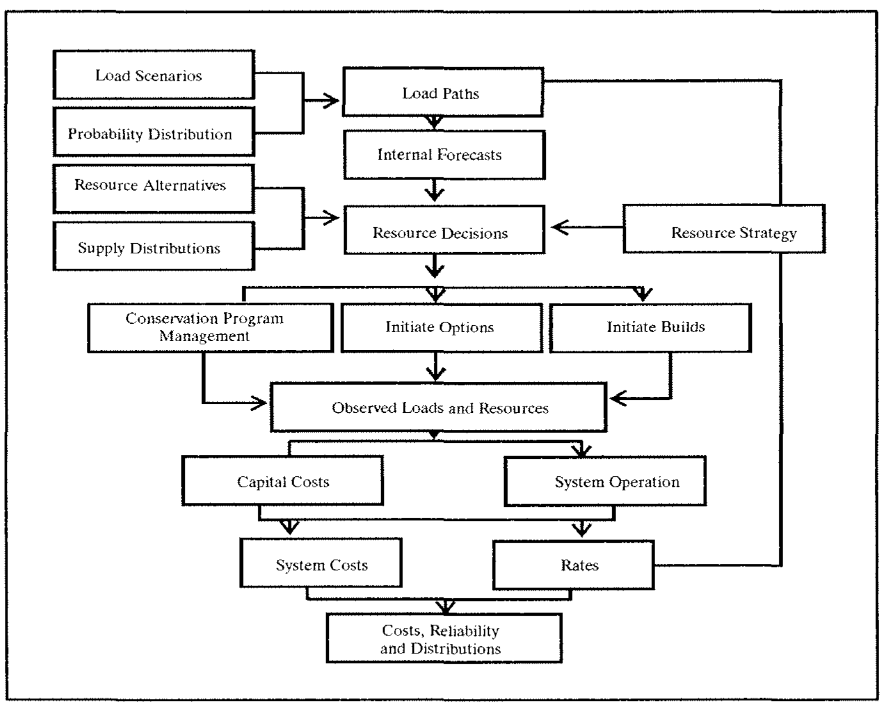


Figure 15-1
Flow of Information in ISAAC

Institutional Structure

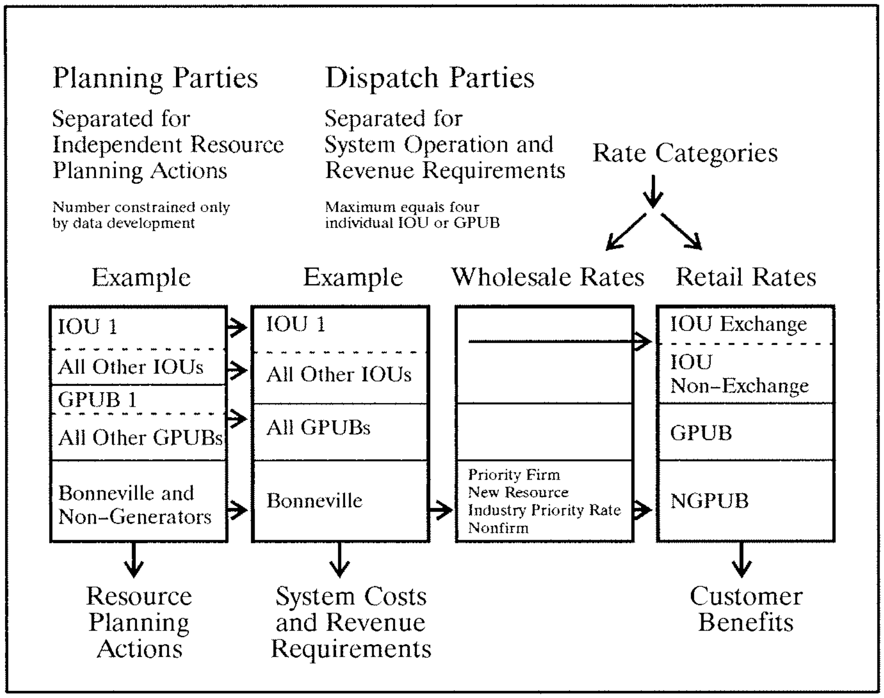


Figure 15-2
Treatment of Various Types of Northwest Utilities

allows either the generating public group or the investor-owned utility group to be broken down into two groups. In studies where more than three planning parties are defined for a study, the user can specify a planning party to keep separate in the system operation routines as the fourth dispatch party. This new group will typically represent an individual utility and will have been defined as an individual planning party. All other planning parties will have their loads and resources aggregated into either the Bonneville, generating public or investor-owned utility groups for the system operation simulation. The ability to isolate a planning party as the fourth party in the dispatch party allows the model to track all of the costs associated with the expansion plans of an individual utility.

The final major category for organizations is that of electrical rates. Rates are calculated at both the wholesale and retail level. At the wholesale level, Bonneville's priority firm, new resource, nonfirm and industrial power rates are calculated. At the retail level, rates are differentiated according to average investor-owned utility domestic and rural rates, investor-owned utility commercial and industrial rates, average generating public rates, and average non-generating public rates.

Treatment of Load Uncertainty

ISAAC currently has two alternative methods for treatment of non-aluminum industry loads. The method described here is the method used by the Council for characterization of load uncertainty. An alternative method is used primarily by Bonneville. The differences in the alternatives are largely methodological and are not believed to produce substantively different results. Efforts are underway to merge the two methods into a single approach.

One of the first steps taken by the model in a pass through the future is the creation of a load path for non-aluminum industry loads. This process is shown on Figure 15-3. The four detailed load forecasts are used to define a trapezoidal probability distribution for long-term load growth. A random selection is made from this distribution and is used to calculate the observed load at the end of the planning horizon. Because the input load forecasts do not have constant load growth rates over the entire planning horizon, a trend growth pattern is determined to reflect the general time series structure of the forecast. Once this load growth trend has been developed, the trend growth rates are modified with a series of random shocks to introduce volatility into the load path. The parameters influencing the amount of volatility in the load paths are controllable by the user.

Random Loads

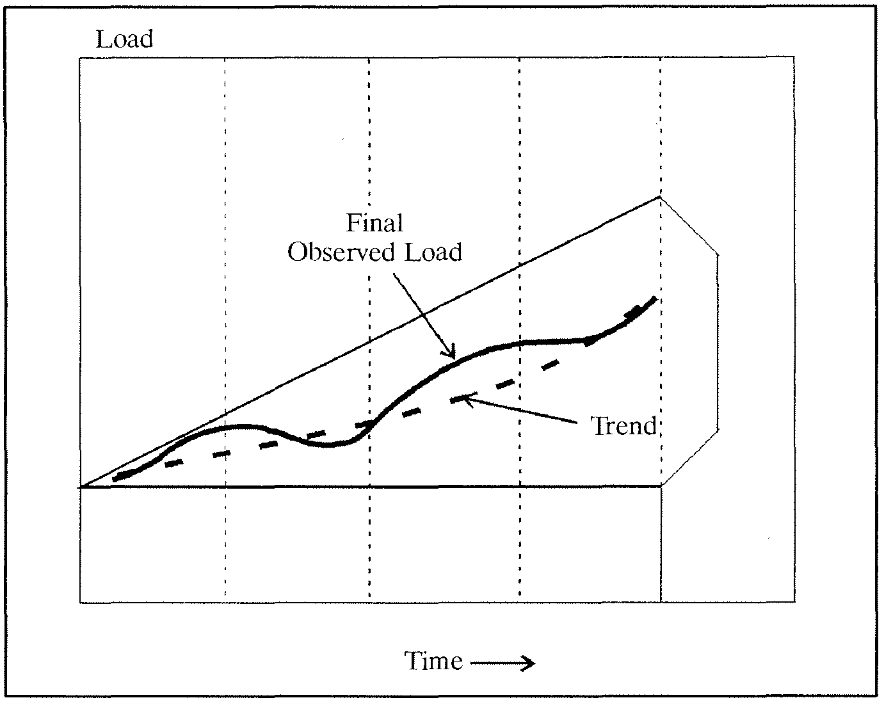


Figure 15-3
Load Path Development Process for Non-Direct Service Industry Loads

Figure 15-4 is an illustration of the observed load paths generated by the model. It is a scatter diagram of regional non-aluminum industry load against time for a study in which only 50 load paths were generated. The Council uses at least 100 paths in an actual study. Each dash represents a load level that the model will observe as it moves through the future. The solid lines represent a set of continuous load paths that would be followed by the model. Alternative load paths all start at a particular load level in a particular year, but may end up at any point between the low and high forecasts. The user has control over the size of the load range, the shape of the distribution of ending load values, and the amount of volatility present in the individual load paths. However, the model has only internal forecasts of where a load path eventually will lead. It has limited forecasting ability and continually updates forecasts as it moves through time, but it is blind to the future load within the limits of the forecast range. Forecast and observed loads are broken down into the loads required for utility planning activities, system dispatch and rate calculations, through a set of ownership and allocation matrices.

Aluminum Industry Model

The other component of load uncertainty is that associated with the direct service industry aluminum smelter loads. ISAAC contains an aluminum industry submodel that generates forecast and observed values for direct service industry loads. This submodel uses an aggregate picture of the aluminum industry in the Northwest, rather than focusing on individual smelters. The market price for aluminum is treated as a random variable. It is assumed to be normally distributed, with a user-specified, long-term mean and standard deviation. The level of aluminum load is driven principally by forecast and observed prices for aluminum.

Loads are determined through two major components. The first is a long-run smelter capacity decision. It is made through a method that describes smelter capacity as a function of estimated present value of aluminum production profits. The upper and lower bounds for capacity and the parameters defining capacity as a function of net present value are user defined. The actual amount of aluminum load is driven by a function that describes how much of the smelter capacity will be used based on costs of production and the price of aluminum. Aluminum load forecasts are done annually and are based on forecasts of aluminum price. These forecasts are used in the system expansion routines for acquisition of resources. Observed load levels are determined quarterly, and are based on observed prices for aluminum. The observed load levels are used in the system operation routines. The direct service industry variable rate is modeled and is assumed to be in effect through 1996. Improved aluminum plant efficiency through the conservation modernization (Con-Mod) program is modeled and is controlled externally through user inputs.

Load Outcomes

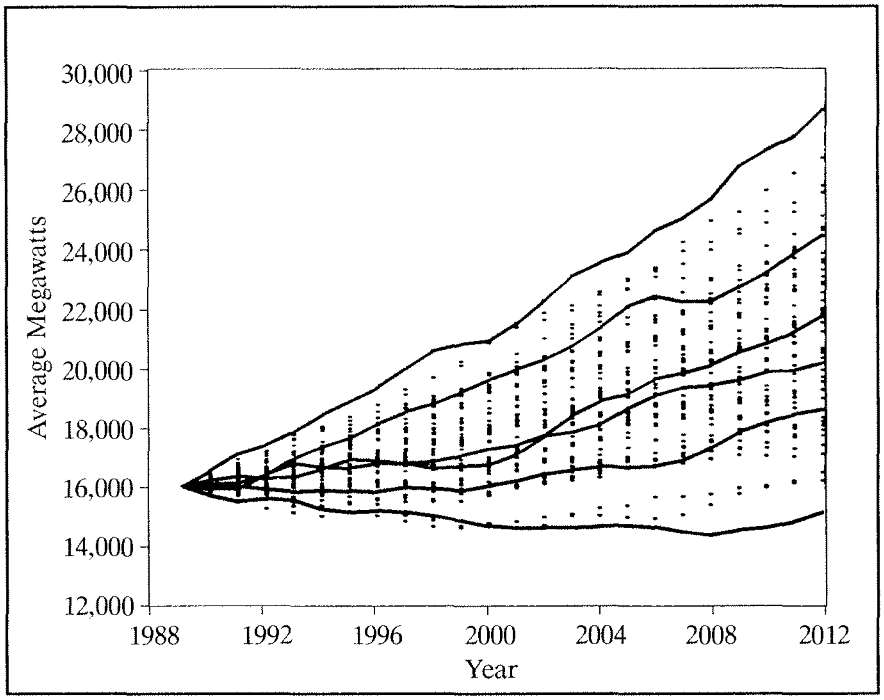


Figure 15-4
Example
Load Distribution

One thing to note about the aluminum load logic is that it produces loads that are largely independent of the level of regional non-direct service industry load. This is a departure from the assumption in the detailed load forecasts, where high direct service industry loads accompany the high forecast, low loads accompany the low forecast, etc. In ISAAC, the assumption is that long-run aluminum prices are driven by world markets, and will be determined independently from regional economic conditions. While the pattern of correlation between direct service industry and non-direct service industry loads differs from the detailed demand forecasts, the range of loads should not. ISAAC's aluminum submodel is usually calibrated to result in approximately the same range of aluminum industry loads as contained in the detailed demand forecasts.

Option and Build Requirements

Two of the input parameters defining the resource strategy are the option level and build level. The option level governs the amount of resource for which options would be acquired and held in inventory. The build level governs the amount of resource moved out of inventory and into actual construction as well as the acquisition efforts for conservation programs. The option and build levels represent levels within the range of load uncertainty to use as guides for making resource decisions.

An example is shown in Figure 15-5. In this example, the region has moved out along a somewhat random load path and finds itself at load level "L" in time period "T." The future load path is still unknown, and decisions must be made in the face of this uncertainty. To do this, a range forecast is first made from period "T," and a probability distribution is applied to the forecast range. The length of the forecast corresponds to the longest lead time of available resources. The range of this new forecast range is likely to be narrower than the original range in the same time period. The high growth rate still is achievable, but since the model is now at a middle point in the range, it is very unlikely that it will ever reach the original high load path. Within this range, further forecasts must be made to use as a guide in making option decisions and build decisions.

The approach shown here is to develop a 50-percent cumulative probability (median) forecast and add or subtract constant energy amounts to develop the option and build forecast. In this example, 1,500 average megawatts is added to the median forecast to generate the option forecast. The build level adjustment is zero, and the build forecast is identical to the median forecast. Another alternative for specification of the option and build levels is to use only cumulative probabilities within the conditional forecast range. For example a 90-percent option level would correspond to a forecast level that 90 percent of conditional load paths would be below. Once these forecasts have been made, a set of resource priorities is used to guide resource decisions. Conservation acquisition and generating resource build decisions are guided by the build-level forecast. Generating resource option decisions use the option-level forecast as a target.

Load Targets

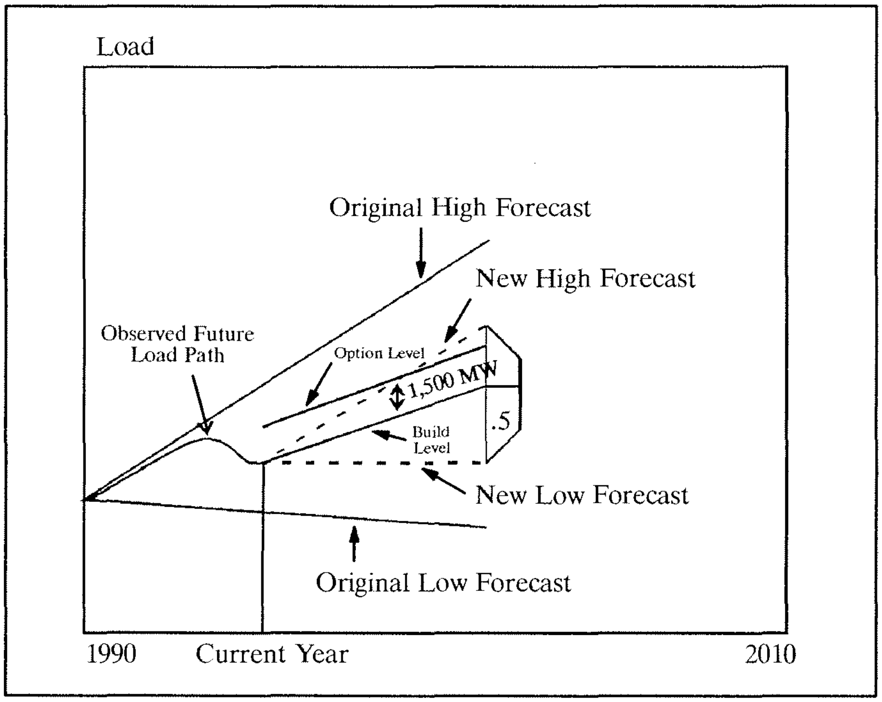


Figure 15–5
Example of Option and Build Levels

Resource Scheduling Decisions

The level of need for resource decisions is determined by subtracting existing system resources and the energy associated with previous decisions from the option-level and build-level target forecasts. Figure 15–6 shows an example of this calculation. This diagram shows the energy of existing resources, plus the energy resulting from a set of conservation acquisition and generating resource build decisions that were made in previous years. Note that not all of this new resource is likely to be online in the model's current year, but will come online as resources complete construction. The difference between these resources and the build forecast represents the amount of energy the model will attempt to secure from additional conservation and generating resource build decisions. The need for additional resource options is determined by comparing the target option forecast to the sum of existing resources, energy from previous conservation and build decisions, and potential energy from previous option decisions if fast-tracked into construction.

Conceptually, the process of making decisions concerning resource development in ISAAC is straightforward. The objective of the model's system expansion logic is to make decisions as consistently as possible with the user-defined resource strategy. As just discussed, the option and build levels are two components of a resource strategy. The other elements include a specified priority order for resource development, a set of constraints on resource availability and, potentially, a set of forced decisions to be made regardless of need. Note that the conservation programs and generating resources are freely mixed in the resource priority order. Also, the priority order is externally defined by the user. It is not determined internally on the basis of forecast resource economics. The Council ultimately develops a priority order by first screening resources based on levelized costs. It then makes multiple trials of priority orders using ISAAC to capture the system-cost impacts of unit size, lead time, seasonal shape, secondary energy markets, integration into the existing system and uncertain variables. Finally, the Council makes modifications to the priority order, based on judgment, to account for the qualitative factors excluded from the analysis.

Resource decisions are made by stacking the remaining energy available from conservation programs and generating resources under the build and option requirements in accordance with the priority order. Forced decisions specified by the user are made regardless of need as are acquisitions of non-discretionary conservation programs. For discretionary decisions, recognition is made of lead times and development rate constraints. If energy from a resource is needed at a point in time that is equal to or less than its lead time, an action is taken on the resource. If the resource is expected to be needed at a point beyond its lead time, the action is deferred. Build decisions on generating resources consider only the construction lead time and can only be made on generating resources that

Need for Decisions

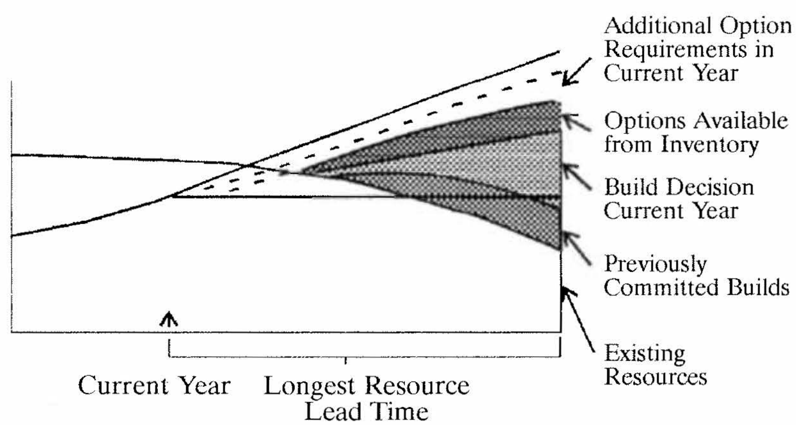


Figure 15-6
Determination of Option and Build Requirements

have completed pre-construction activities and are currently in the option inventory. Option decisions consider the total generating resource lead time. Conservation programs use a user-defined scheduling window to determine program management actions.

There can be occurrences where the resource priority order is not followed explicitly. Constrained development rates can cause parallel development of many resources. The model's highest priority is to maintain the reliability targets specified. Events, such as sudden spurts in load growth, may require scheduling resources with lower priority, but shorter lead time, in order to maintain balance with respect to the option and build levels specified. It is also possible that reductions in observed load growth may cause options to expire before they can be used and may lead to choosing resources out of order.

Conservation Program Modeling

The conservation modeling capability within ISAAC is fairly extensive. A program is described through specifying a number of physical, economic and program management characteristics. Supply curves are defined through specifying program units available as a function of time and load level, in combination with values for savings per unit. As many different conservation programs as needed can be specified. The Council typically uses 12 to 15 different programs in its resource portfolio modeling.

Conservation program types in ISAAC fall into four categories. The first type, typically referred to as a non-discretionary program, will have units automatically secured regardless of need for the program's energy. This is exemplified by programs that would be implemented by building code, such as the residential model conservation standards or new appliance efficiency standards. The units for this program type represent new purchases (e.g., new refrigerators purchased). Use of this program type forces acquisition of all new units and avoids the creation of lost opportunities. If the savings are not secured at the point of purchase, the opportunity will not arise again until the end of the lifetime of the newly purchased less-efficient unit. The number of units acquired for a non-discretionary program will usually be linked to the observed load path. The higher levels of economic activity associated with the higher load growth paths will provide more conservation savings potential than at lower paths.

The second program type is similar to the first in that the units for potential acquisition represent new purchases. However, this is a discretionary program. That is, the units are not automatically acquired, but are secured through program management decisions. If the energy savings for a type-two program are not needed, they probably will not be acquired. Use of this program could simulate the creation of lost-opportunity resources.

The third program type is a discretionary program used to acquire savings from existing end uses. An example of this type would be existing residential weatherization. The principal difference between this program type and the previous one is that it is assumed lack of action does not to create lost opportunities for conservation acquisition. If a house is not weatherized this year, it is still likely to be available for weatherization next year.

The final program type available is a two-stage program and is really a combination of the first and third program types. The first stage is designed to capture the effect of customer actions in a particular sector due to price response in the absence of an active program. When it is determined that the system needs energy from this program, it transitions to an actively managed discretionary program, and program management actions are taken to secure the remaining energy.

Conservation has historically been thought of as a very flexible, short lead time resource. The perception has been that it comes in small amounts and its acquisition could be easily managed to adapt to changing load growth patterns. The experience of the 1980s has shown that, while conservation is an attractive resource, there are limits to its flexibility. This can be caused by any number of factors, but is due primarily to the time it takes to develop conservation delivery mechanisms and to the resistance encountered when changing program design characteristics or utility funding levels.

As discussed earlier, flexibility can affect system economics and cost-effectiveness. The flexibility of discretionary conservation in ISAAC is controlled through a set of program management parameters referred to as acceleration and velocity constraints. These are user defined and specified separately for each discretionary program. These parameters are used to define upper and lower limits for the program activity levels and how quickly they can be changed. They are somewhat analogous to lead times for generating resources. These acceleration and velocity parameters are shown graphically in Figure 15-7. They allow program development to be modeled much as the movement of a car would be, with the activity level of a program analogous to the velocity of the car. Each program has an upper limit to its activity level (maximum velocity) and constraints on how quickly the activity level can change (maximum acceleration and deceleration). A minimum activity level (minimum velocity) required to keep the program viable also is specified. High accelerations and velocities would mean a program is quite flexible and energy could be acquired quickly. Low values would indicate slow acquisition rates and difficulty in changing program activity levels. The modeling of these program constraints provides the ability to value the flexibility or constraints of conservation program development in assessing its cost-effectiveness.

Generating Resource Modeling

Like conservation programs, new generating resources are described through a number of physical and economic characteristics. Some resources, such as WNP-1 and WNP-3, are modeled individually, while others will require some amount of aggregation for computational efficiency. For instance, dispersed resources, such as small

Conservation Constraints

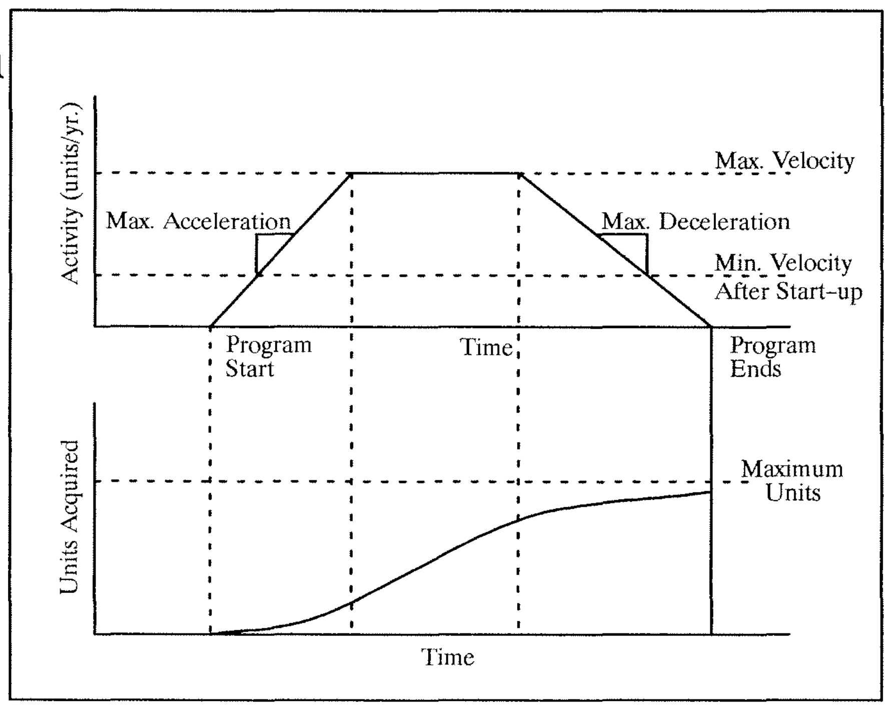


Figure 15-7
Conservation Development Controlled Through Accelerations and Velocities

hydro and cogeneration, are typically aggregated into several generic blocks, and the input parameters describe the average values for the entire block. Supply curves for generating resources are defined by specifying the number of individual units available as a function of both time and load level. If there is more potential available for a resource under high load conditions, or if a user wanted to constrain the resource strategy to acquire a resource only under certain load conditions, these constraints can be modeled. While the supply curves for generating resources generally have some level of aggregation, the resource decisions are made on an individual unit basis.

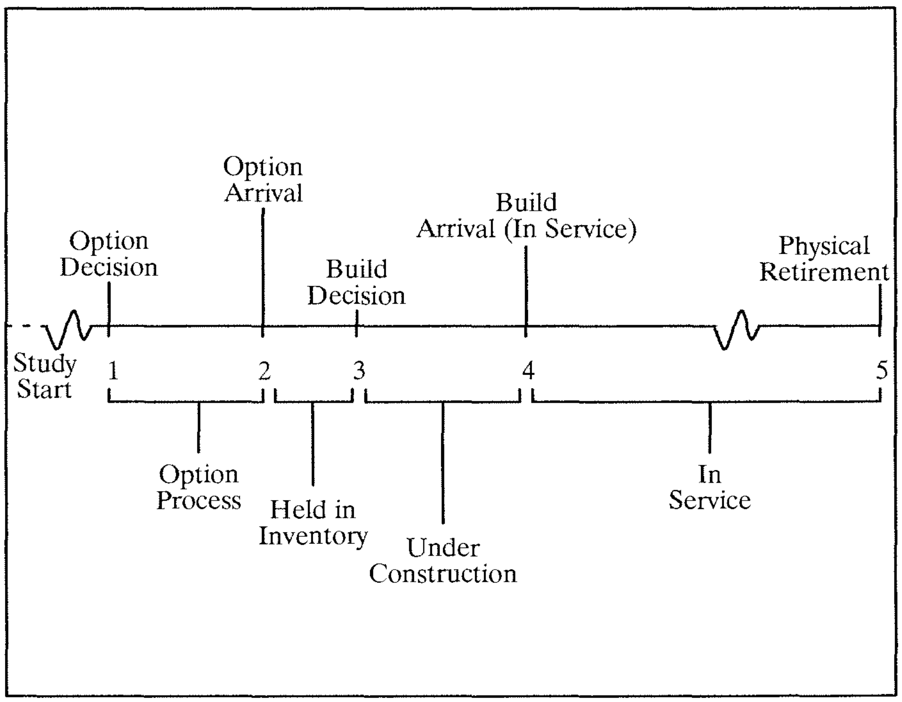
Decisions are made in two steps for all generating resources. The first is a decision to option or start pre–construction activities on a unit; that is, to enter the siting, licensing and design stage. The second decision is to move a unit into the actual construction phase. Once an option decision on a unit is made, the resource moves into a period of pre–construction activity. If the unit successfully completes this stage, it moves into the option inventory. Once an optioned unit is in inventory, it becomes available for a decision to move it into the actual construction phase. Depending on need, it may be held in inventory for several years. Each generating resource has a user–defined inventory shelf life, and if a unit is not built before the end of its shelf life, it either expires and is no longer available as a regional resource, or again becomes a candidate to enter the siting, licensing and design stage. Once a build decision has been made on a generating resource unit, it moves through the construction phase and enters commercial operation where it will be available for dispatch through the end of its physical life. The process is summarized in Figure 15–8.

The timing of generating resource decisions is driven by the option and construction lead times for a resource. Unless forced resource decisions are specified by the user, decisions are delayed for as long as is possible while still meeting the option and build level targets. The user also can specify constraints on the number of units for which option or construction decisions can be made in any given year.

Another of the random variables modeled in ISAAC is the uncertainty associated with the successful completion of the pre–construction phase for a resource, and, if successful, whether it will remain a viable option over the maximum time it can be held in inventory. The user specifies values for the probability that an option will fail during the siting, licensing and design stage, and for the chance of an option failing over the period it is held in inventory. These input values are used to define the probability density functions for option failure during both the option and hold period. These are shown in Figure 15–9. The option failure distribution is treated as uniform over the option period; that is, if the attempt to gain the option fails, it has an equally likely chance of failing at any point during the pre–construction period. If the option is successful and moves into inventory, the probability of failure

Resource Milestones

Figure 15–8
Timing of Events for Generating Resources



Option Uncertainty

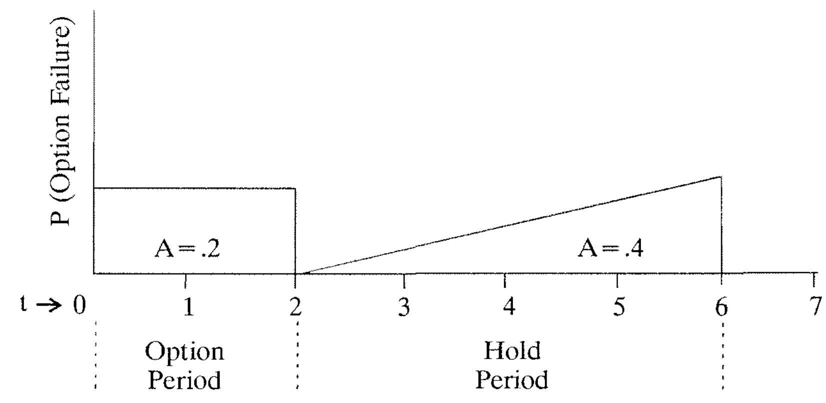


Figure 15-9
Options Can Fail During Pre-Construction or While in Inventory

starts at zero and increases linearly to the end of the option's shelf life. This represents a condition where the longer an option is held on the shelf, the higher the probability is that it will be lost before a decision is made to construct. The model takes random samples from these distributions, first to determine if and when the option fails during the pre-construction period. If the unit successfully completes this phase, a sample is taken from the hold period density function to determine if and when it fails during its stay in inventory. As option failures happen, information on the occurrence flows into the decision-making routines so corrective actions can be taken.

If a generating resource unit makes it all the way through the option or pre-construction stage and is moved into construction before an option failure occurs, it moves into commercial operation at the end of its construction period with certainty. In ISAAC, all of the uncertainty regarding the completion of a generating unit is resolved in the siting, licensing and design stage and during the period it is in inventory. Once a resource has negotiated the hurdles required to move into construction, it is assumed that it can be completed successfully.

Resource Supply Uncertainty

One thing many conservation programs and generating resources have in common is uncertainty about future supply. While the Council believes that its data development process produces reasonable and balanced supply estimates, there is no question that today's forecasts of cost and availability for future resource alternatives are highly uncertain. This is especially true of emerging technologies, such as solar photovoltaics, or of resources, such as geothermal, where the ultimate cost-effective energy potential depends on the future confirmation of the size and quality of an uncertain heat source.

ISAAC has algorithms that allow for the modeling of uncertainty in future resource supply and the examination of its impact on today's resource decisions. The methodology used to treat supply uncertainty is illustrated in Figures 15-10 and 15-11. Expected resource supply estimates and the long-term coefficient of variation for the supply distribution are added by the user. The expected supply can be a function of time and load. The supply distribution is assumed to be normally distributed. At the beginning of a pass through the study period, a random sample is taken from the supply distribution. This defines the amount of resource supply that will be observed to be available at the end of the planning period. The percentage difference between the mean and the observed supply is applied uniformly across the planning period to generate the observed supply through time.

As shown in Figure 15-11, planning information for resource decision-making at the start of the study period is based on the mean value for resource supply. This represents the current supply forecast, even though it is in error. Resource decisions are made on the basis of the forecast supply. If a supply forecast is too high, the resource may be counted on for more energy than it ultimately can supply. If the forecast for an inexpensive

Supply Uncertainty

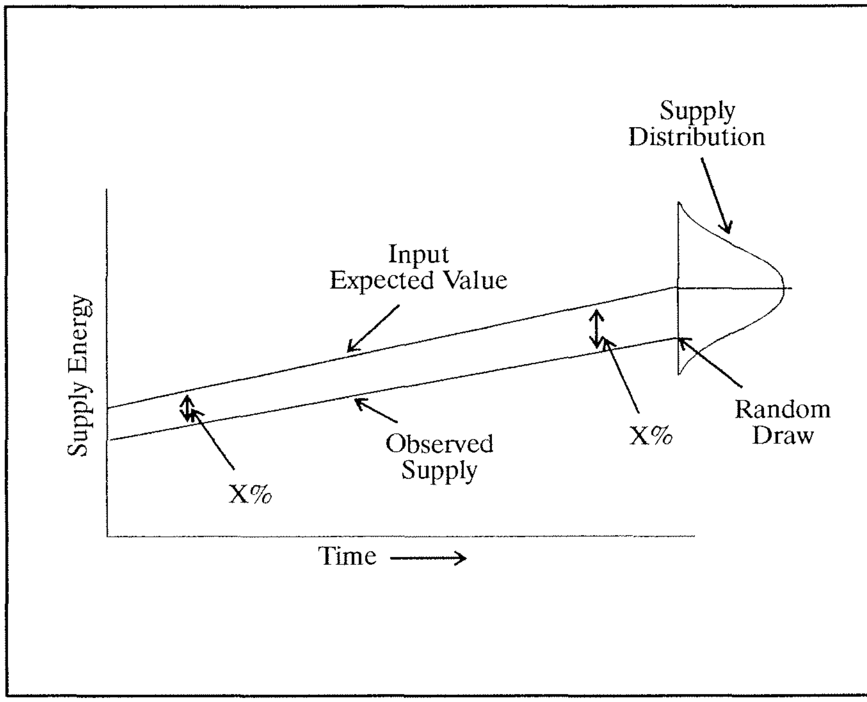


Figure 15-10
Determination of Long-Term Supply

Supply Forecasts

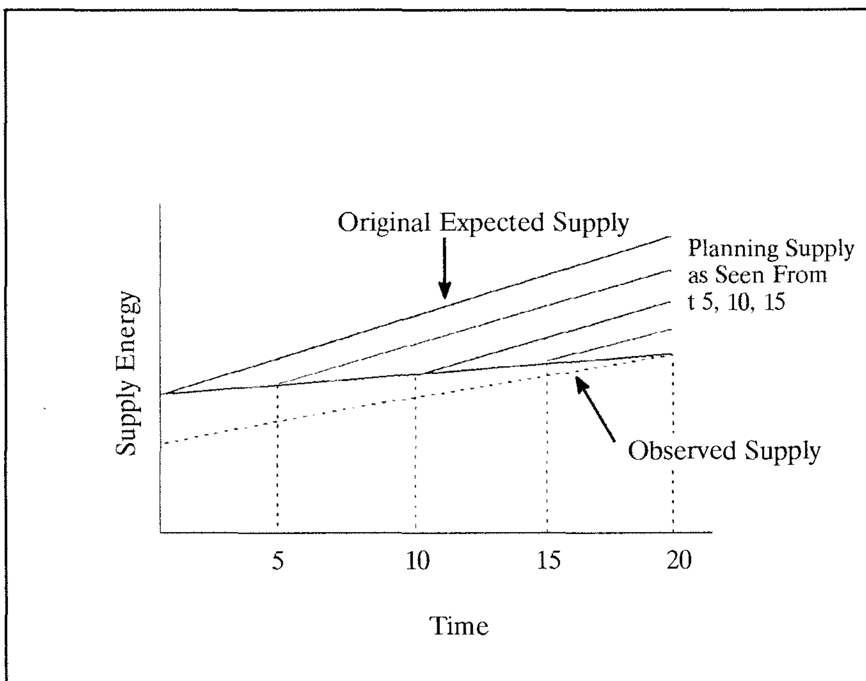


Figure 15-11
Forecasts Improve With Time

resource is too low, some cost-effective opportunities may be missed. As the model moves through the study period, the forecasts for resource supply are gradually adjusted to be consistent with the observed supply, simulating the process of learning more about the "true" resource potential. The resolution of this uncertainty is proportional to elapsed time, and the updated forecasts as seen from several points in time are shown in Figure 15-11. Any options on generating resources that would exceed the observed supply are forced to fail in the option failure process discussed previously. Observed conservation units are limited to the observed supply, even though program targets may exceed it. The impact of errors that are made because of inaccurate supply forecasts are captured in the simulation and can help identify the risks associated with overdependence or underdependence on uncertain resources.

Fuel Price Uncertainty

An additional uncertainty treated in ISAAC is that associated with long-term fuel prices for generating resources. This effect is especially important to capture for high variable cost resources such as combustion turbines, gas-fired cogeneration, or rail-haul coal plants. Uncertainty in fuel prices can add significantly to the risk carried by the region, if substantial new commitments are made to these resources.

The algorithm for treatment of fuel price uncertainty is quite similar to that used for long-term load uncertainty. The process is illustrated in Figure 15-12. The inputs for fuel price include an initial price in some reference year and an annual stream of real escalation rates. These are used to develop a time series for fuel prices, which serves as the expected value of price through time. Additionally, a coefficient of variation is specified, which is used to generate a normal distribution for fuel prices at the end of the planning horizon. At the beginning of a load path, a sample is taken from this distribution. This defines the ending fuel price for this pass through the future. The ratio of observed to expected price is used to develop a long-term trend fuel price pattern. The trend growth rates are then modified with a series of random shocks to introduce volatility into the fuel price path. The parameters influencing the amount of volatility produced are controllable by the user.

ISAAC has inputs for both variable-fuel and fixed-fuel price components for all generating resources, and fuel price uncertainty affects both components. It can be applied to any subset of both new and existing resources. Additionally, it is possible to model correlated fuel price groups. For example, if gas prices for combustion turbines are significantly higher than expected, prices for gas-fired cogeneration can be specified to show this same general pattern of escalation. Finally, because of the importance of revenues derived from the Pacific Southwest secondary energy market, dynamic adjustments can be made to the price structure of the Southwest market to reflect random variations in the generating resource fuel prices that would be experienced in the Southwest.

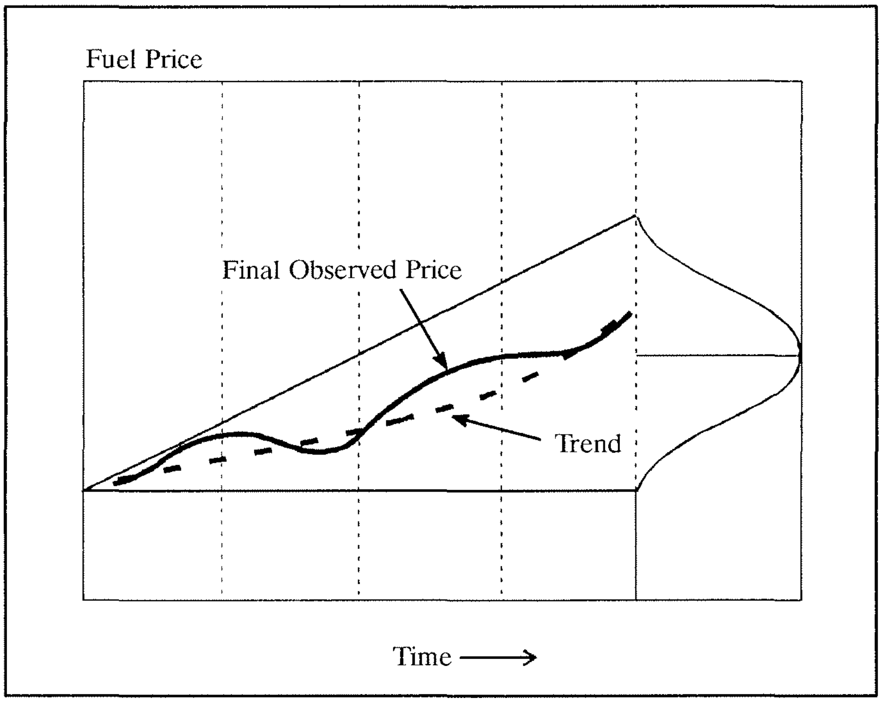
System Operation

System operation and production costing is based on a composite model of the Northwest's hydroelectric system. Because of the dominance of the Northwest's hydroelectric system, ISAAC is an energy model only; there is currently no treatment of capacity. Simulation of hydropower system operation is based on a one-dam model in which total hydro energy capability, natural streamflow energy, reservoir draft, and limits on draft and refill for the entire system are specified as single values for the various seasons and water conditions. Data for the hydropower model is based on the result of critical period studies and the 40-year hydro regulation studies performed as part of the Northwest Regional Forecast. To capture the impact of streamflow variability, each year the model randomly chooses a water condition based on probabilities associated with the 102-year water record. Four discrete time periods are used for evaluation within each operating year: September through December, January through April, May, and June through August. May is modeled separately to provide better resolution on the system impact of the spring fish flows.

Within the dispatch, all resources fall into one of six categories: nuclear, low-operating-cost coal, high-operating-cost coal, simple-cycle combustion turbines, combined-cycle combustion turbines and load-reduction resources. The non-dispatchable resources, principally conservation and renewables, are usually modeled as load-reduction resources, with seasonally shaped energy contributions. Thermal units are modeled with deration through their equivalent availability, and are shaped seasonally according to specified maintenance schedules. Nuclear units are treated as must-run resources. All other thermal operation is modeled with economic dispatch against firm, interruptible and secondary market load blocks, as needed under the various hydro conditions. The secondary market is modeled as a four-tiered market with seasonal prices and seasonally shaped demand blocks changing through time. Transmission access to Northwest parties and BC Hydro is guided by the long-term intertie access policy. If firm regional load cannot be met with regional resources, attempts are made to buy energy from out of region markets in Canada and the Pacific Southwest. The Council currently assumes up to 1,500 megawatts of energy is available from the Southwest at natural gas-fired combustion turbine prices. Any firm load that cannot be met through these emergency purchases is assumed to be curtailed and is costed at a user-specified price. (The Council currently uses 15 cents per kilowatt-hour for firm curtailments.) Curtailments of interruptible load are priced near interruptible rates.

Random Fuel Prices

Figure 15-12
Fuel Price Development Process



As mentioned previously, the system operation logic accommodates either three or four dispatch parties, depending on user specification. In a three-party dispatch, operations, costs and revenues are tracked separately for Bonneville, the aggregate generating publics and the aggregate investor-owned utilities. In a four-party dispatch, an individual generating public or investor-owned utility can be further isolated. Dispatch parties are modeled with their own loads and resources and have individual rights to firm hydro, secondary energy, intertie access, etc. Rights to interchange are modeled, as are economic transactions between Northwest parties. The four-party dispatch option allows estimates for all of the system costs associated with an individual utility planning strategy to be captured and isolated in the simulation.

Financial Analysis

Financial modeling in ISAAC is performed through a two-step process. At the beginning of a study, a submodel referred to as Microfin performs detailed calculations for capital revenue requirements for each possible resource and sponsor combination. These are translated into a set of factors expressing yearly real capital revenue requirements as a proportion of the cost of the resource and are stored for later use. Then in the simulation, whenever a resource is developed by a sponsor, the appropriate set of factors is used to estimate the stream of nominal capital revenue requirements for that resource.

Microfin treats both conservation programs and generating resources. Annual revenue requirements can be made up of a number of cost components. These include return on debt, return on equity, depreciation, state and federal taxes, deferred state and federal taxes, insurance, property tax and gross revenue tax. Direct capital expenditures for a resource are spread over the construction period according to user-defined cash flow distributions. User options allow the selection of rate-base inclusion of construction work in progress, or to accumulate an allowance for funds used during construction, with no return allowed on either the direct or indirect investment until the resource is placed in-service. A further option to simulate Bonneville financing through Treasury borrowing also is allowed. In addition, provisions are made to accommodate the Bonneville acquisition of resources that would be developed by a party placing requirements contracts on Bonneville or by an independent power producer.

Only the capital expenditures associated with construction of a resource are financed. Generating resource option costs are expensed uniformly over the pre-construction period. If a resource fails during the option process, its option expenses are prorated according to how far it had gone through the process before it failed. Option hold costs required to maintain an option on a resource while it is held in the option inventory are expensed, as are the administrative costs associated with conservation programs. For conservation programs, user-defined incentive levels are used to control how much of the conservation investment is funded by utilities and how much by consumers. The financial parameters and accounting methods for utilities and consumers can be defined separately.

Rates and Price Effects

ISAAC includes a rates module that estimates Bonneville wholesale rates and average utility retail rates for a number of rate categories (see Figure 15-2). The rates methodology is fairly complex, and a description here would be overly ambitious. The logic is a somewhat streamlined version of Bonneville's more detailed models (e.g., the Supply Pricing Model), but is considered adequate to capture the general rate effects of differing resource strategies.

Price elasticity of demand can have an effect on the cost-effectiveness and need for resources, and is treated in the model. The detailed demand forecasts that are inputs to ISAAC are developed through detailed end-use and econometric models. These forecasting models calculate changes in price and the resulting response in loads. That is, price effects already have been accounted for at the price levels underlying the detailed forecasts. In ISAAC, further adjustments to demand due to price only are required if the resource strategy produces prices that are inconsistent with those underlying the detailed forecasts. To allow the model to track these differences, a reference price structure is entered, which defines the level of prices associated with the detailed forecasting models as a function of load path. As a random load path within ISAAC unfolds, this reference-price/reference-load structure is used to discern whether the observed prices are consistent with the reference prices associated with the detailed forecasts. If they are consistent, no further adjustment due to price effects is required. If loads and prices are determined to be out of equilibrium, appropriate adjustments to load are made.

GLOSSARY

administrative costs
Certain overhead costs related to conservation or generating resources, such as project management and accounting costs incurred by utility or contractor staff.

alternating current (AC)
An electric current in which the electrons flow in alternate directions. In North American electrical grids, this reversal of flow is governed at 60 cycles per second (Hertz). With some exceptions (see "direct current"), commercial electric generation, transmission and distribution systems operate on alternating current.

anadromous
Fish that hatch in freshwater, migrate to the ocean, mature there, and return to freshwater to spawn. For example, salmon or steelhead trout.

available technology
In this power plan, the term "available technology" refers to equipment or facilities for generating and conservation resources, including electrical appliances, that are currently available and are expected to be generally available in the marketplace during the 20-year planning period.

average cost pricing
A concept used in pricing electricity. The average cost price is derived by dividing the total cost of production by the total number of units sold in the same period to obtain an average unit cost. This unit cost is then directly applied as a price.

average megawatt or average annual megawatt
Equivalent to the energy produced by the continuous operation of one megawatt of capacity over a period of one year. (Equivalent to 8.76 gigawatt-hours, 8,760 megawatt-hours or 8,760,000 kilowatt-hours.)

avoided cost
An investment guideline, describing the value of conservation and generation resource investments in terms of the cost of more expensive resources that would otherwise have to be acquired.

base loaded resources
Base loaded electricity generating resources are those that generally are operated continually except for maintenance and unscheduled outages.

billing credit
Under the Northwest Power Act, a payment by Bonneville to a customer (in cash or offsets against billings) for actions taken by that customer to reduce Bonneville's obligations to acquire new resources.

Bonneville Power Administration (Bonneville)
A federal agency that markets the power produced by Federal Base System resources and resources acquired under the provisions of the Northwest Power Act of 1980. Bonneville sells power to public and private utilities, direct service industrial customers and various public agencies. The Northwest Power Act charges Bonneville with other duties, including pursuing conservation, acquiring sufficient resources to meet its contract obligations, funding certain fish and wildlife recovery efforts and implementing the Council's plan.

Btu (British thermal unit)
The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit (3,413 Btus are equal to one kilowatt-hour).

buy-back program
A conservation program that, in effect, purchases electrical energy in the form of conservation measures installed by a consumer. The consumer is paid a certain amount per kilowatt-hour of energy saved.

callback
A power sale contract provision that gives the seller the right to stop delivery of power to the buyer when it is needed to meet other specified obligations of the seller.

capacity
The maximum power that a machine or system can produce or carry under specified conditions. The capacity of generating equipment is generally expressed in kilowatts or megawatts. In terms of transmission lines, capacity refers to the maximum load a line is capable of carrying under specified conditions.

climate zone
As part of its model conservation standards, the Council has established climate zones for the region based on the number of heating degree days, as follows: Zone 1: 4,000–6,000 heating degree days (the mild maritime climate west of the Cascades and other temperate areas); Zone 2: 6,000–8,000 heating degree days (the somewhat harsher eastern parts of the region); and Zone 3: more than 8,000 heating degree days (western Montana and higher elevations throughout the region).

coal gasification
The process of converting coal to a synthetic gaseous fuel.

cogeneration
The sequential production of electricity and useful thermal energy. This is frequently accomplished by the recovery of reject heat from an electric generating plant for use in industrial processes, space or water heating applications. Conversely, cogeneration can be accomplished by using reject heat from industrial processes to power an electricity generator.

combined–cycle power plant
The combination of a gas turbine and a steam turbine in an electric generation plant. The waste heat from the gas turbine provides the heat energy for the steam turbine.

combustion turbine
A turbine engine generator, often fired by natural gas or fuel oil, used to generate electricity. The turbine generator is turned by combustion gases rather than heat–created steam.

conductor
Wire or cable for transferring electric power.

conservation
According to the Northwest Power Act, any reduction in electric power consumption as a result of increases in the efficiency of energy use, production or distribution.

construction lead time
The length of time between a decision to construct a resource and when the resource is expected to deliver power to the grid. Generally defined for purposes of this plan as the interval between detailed engineering and equipment order to completion of start–up testing.

cost–effective
According to the Northwest Power Act, a cost–effective measure or resource must be forecast to be reliable and available within the time it is needed and to meet or reduce electrical power demand of consumers at an estimated incremental system cost no greater than that of the least–costly, similarly reliable and available alternative or combination of alternatives.

cost of debt
The amount paid to the holders of debt (bonds and other securities) for use of their money. Generally expressed as an annual percentage in this plan.

cost of equity
Earnings expected by a shareholder on an investment in a company. Generally expressed as an annual percentage in this plan.

critical period
The sequence of low water conditions during which the regional hydropower system's least amount of energy can be generated (see "critical water") while drafting storage reservoirs from full to empty. Under the Pacific Northwest Coordination Agreement, critical period is based on the lowest multimonth streamflow observed since 1928. Based on analysis of streamflows at The Dalles Dam, this is also the lowest streamflow since recordkeeping began in 1879.

critical water
The sequence of streamflows in the critical period under which the hydropower system will generate about 12,500 average megawatts. In an average year, the Northwest hydropower system will produce about 16,600 average megawatts.

curtailment
An externally imposed reduction of energy consumption due to a shortage of resources.

debt
Investment funds raised through the sale of securities having fixed rates of interest.

debt/equity ratio
The ratio of debt financing to equity financing used for capital investment.

demand forecast
An estimate of the level of energy that is likely to be needed at some time in the future. The Council's demand forecast contains a range of estimated consumption based on various assumptions about demographics and the state of the economy.

direct application renewable resource
Technologies that use renewable energy sources to perform a task without converting the energy into electricity. These sources and their functions may include wood for space heat, solar for space heat and drying, geothermal space and water heating, and wind machines used for mechanical drive (such as pumping).

direct current (DC)
An electrical current in which the electrons flow continuously in one direction. Direct current is used in specialized applications in commercial electric generation, transmission and distribution systems.

direct service industry
An industrial customer that buys power directly from the Bonneville Power Administration. Most direct service industries are aluminum smelting plants.

discount rate
The rate used in a formula to convert future costs or benefits to their present value. For a detailed explanation, see Volume II, Chapter 13.

dispatch
Operating control of an integrated electrical system involving operations such as control of the operation of high-voltage lines, substations or other equipment.

distribution
The transfer of electricity from the transmission network to the consumer. Distribution systems generally include the equipment to transfer power from the substation to the customer's meter.

drawdown
Release of water from a reservoir for purposes of power generation, flood control, irrigation or other water management activity.

economic feasibility
The Northwest Power Act requires all conservation measures to be "economically feasible" for consumers. The Act does not define this concept. In this plan, the Council considers a program or measure to be economically feasible if the measure or program results in the minimum life-cycle costs to the consumer, taking into account financial assistance made available pursuant to other provisions of the Act.

end use
A term referring to the final use of energy. In the aggregate, it is used the same as "energy demand." In more detailed use, it often refers to the specific energy services (for example, space heating), or the type of energy-consuming equipment (for example, motors).

energy
That which does, or is capable of doing, work. Energy is measured in terms of the work it is capable of doing. Electrical energy is commonly measured in kilowatt-hours, or in average megawatts (8,760,000 kilowatt-hours).

energy services
The actual service energy is used to provide (for example, space heat, refrigeration, transportation).

equity
Investment funds raised through the sale of shares of company ownership.

equivalent availability
The ratio of the maximum amount of energy a generating unit can produce in a fixed period of time, after adjustment for expected maintenance and forced outage, to the maximum energy it could produce if it ran continuously over the fixed time period. This represents an upper limit for a long-run (annual or longer) capacity factor for a generating unit. For example, a unit with an equivalent availability of 70 percent and a capacity of 500 megawatts could be relied on to produce 350 average megawatts of energy over the long term, if required.

externality
Any costs or benefits of goods or services that are not accounted for in the price of the goods or services. Specifically, the term given to the effects of pollution and other environmental effects from power plants or conservation measures.

Federal Base System
The system includes the Federal Columbia River Power System hydroelectric projects, resources acquired by the Bonneville Power Administration under long-term contracts prior to the Northwest Power Act, and resources acquired to replace reductions in the capability of existing resources subsequent to the Act.

Federal Energy Regulatory Commission (FERC)
A federal agency that regulates interstate aspects of electric power and natural gas industries. It has jurisdiction over licensing of hydropower projects and setting rates for electricity sold between states. FERC was formerly the Federal Power Commission.

firm capacity
That portion of a customer's capacity requirements for which service is assured by the utility provider.

firm energy
That portion of a customer's energy load for which service is assured by the utility provider. That portion for which service is not assured is referred to as "interruptible."

firm energy load carrying capability (FELCC)
The amount of firm energy that can be produced from a hydropower system based on the system's lowest recorded sequence of streamflows and the maximum amount of reservoir storage currently available to the system.

firm surplus
Firm energy in excess of the firm load.

fuel cycle
The series of steps required to produce electricity from power plants. The fuel cycle includes mining or otherwise acquiring the raw fuel source, processing and cleaning the

fuel, transporting, generating, waste management and plant decommissioning.

generation
The act or process of producing electricity from other forms of energy.

geothermal
Useful energy derived from the natural heat of the earth as manifested by hot rocks, hot water, hot brines or steam.

head
The vertical height of water in a reservoir above the turbine.

heat engines
Devices that convert thermal energy to mechanical energy. Examples include steam turbines, gas turbines, internal combustion engines and Stirling engines.

heat rate
The amount of input (fuel) energy required by a power plant to produce one kilowatt-hour of electrical output. Expressed as Btu/kWh in this plan.

heating degree days
A measure of the amount of heat needed in a building over a fixed period of time, usually a year. Heating degree days per day are calculated by subtracting from a fixed temperature the average temperature over the day. Historically, the fixed temperature has been set at 65^0 Fahrenheit, the outdoor temperature below which heat was typically needed. As an example, a day with an average temperature of 45^0 Fahrenheit would have 20 heating degree days, assuming a base of 65^0 Fahrenheit.

hydroelectric power (hydropower)
The generation of electricity using falling water to turn turbo-electric generators.

independent power producer (IPP)
An independent power producer is a power production facility that is not part of a regulated utility. Power production facilities that qualify under PURPA (see "qualifying facility") are considered independent power producers, together with other independent power production facilities, such as independently owned coal-fired generating plants.

infiltration control
Conservation measures, such as caulking, better windows and weatherstripping, which reduce the amount of cold air entering or warm air escaping from a building.

insolation
The rate of energy from the sun falling on the earth's surface, typically measured in watts per square meter.

integrated resource planning
See "least-cost planning."

interruptible power
Power that, by contract, can be interrupted in the event of a power deficiency.

intertie
A transmission line or system of lines permitting a flow of electricity between major power systems.

investor-owned utility
A utility that is organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

ISAAC
A computer model used by the Council to simulate system operation, decisions to option and build resources, and the associated costs of providing power across a large number of possible load forecasts. ISAAC accounts for the effects of uncertainty on the load forecast and variations in hydropower availability for analyzing various resource strategies. The Council uses the model to help choose the best mix of resources and to establish the power plan Action Plan.

kilowatt (kW)
The electrical unit of power that equals 1,000 watts.

kilowatt-hour (kWh)
A basic unit of electrical energy that equals one kilowatt of power applied for one hour.

lead time
The length of time it takes to move a resource from concept to completion.

least-cost planning
Least-cost planning or, as it is often called, "integrated resource planning," is a name given to the power planning strategy and philosophy adopted by the Council. This strategy recognizes load uncertainty, embodies an emphasis on risk management, and reviews all available and reliable resources to meet current and future loads. The term "least-cost" refers to all costs, including capital, labor, fuel, maintenance, decommissioning, known environmental impacts and difficult to quantify ramifications of selecting one resource over another.

levelized life-cycle cost
The present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments. This stream of payments can be converted to a unit cost of energy by dividing them by the number of kilowatt-hours produced or saved by the resource in associated years. By levelizing costs, resources with different lifetimes and generating capabilities can be compared.

life–cycle costs
See "levelized life–cycle cost."

load
The amount of electric power required at a given point on a system.

load forecast
An estimate of the level of energy that must be generated to meet a need. This differs from a demand forecast in that transmission and distribution losses from the generator to the customer are included.

load path
One future scenario for electric load growth, as opposed to a range that accommodates multiple forecasts of future load growth.

lost–opportunity resources
Resources that, because of physical or institutional characteristics, may lose their cost–effectiveness unless actions are taken to develop these resources or to hold them for future use.

major resource
According to the Northwest Power Act, a resource with a planned capability greater than 50 average megawatts and, if acquired by Bonneville, acquired for more than five years.

manufactured home
A structure, such as a mobile home, that is transportable in one or more sections, and that is built on a permanent chassis and designed to be used as a dwelling, with or without a permanent foundation, when connected to the required utilities. These homes must comply with the Manufactured Home Construction and Safety Standards issued by the U.S. Department of Housing and Urban Development.

This does not include other categories of homes whose components are manufactured, such as modular, sectional, panelized and pre–cut homes. These homes must comply with state and local building codes.

marginal cost
The cost of producing the last unit of energy (the long–run incremental cost of production). In the plan, "regional marginal cost" means the long–run cost of additional consumption to the region due to additional resources being required. It does not include consideration of such additional costs to any specific utility due to its purchases from Bonneville at average cost.

measure
In this plan, a measure refers to either an individual conservation measure or action or a combination of actions.

megawatt (MW)
The electrical unit of power that equals one million watts or one thousand kilowatts.

mill
A tenth of a cent. The cost of electricity is often given in mills per kilowatt–hour.

model conservation standards
Any energy–efficiency program or standard adopted by the Council, including, but not limited to: 1) new and existing structures; 2) utility, customer and governmental programs; and 3) other consumer actions for achieving conservation. The most well known are the energy–efficient building standards developed by the Council for new electrically heated buildings.

Monte Carlo simulation
The mathematical simulation of uncertain events having known probability characteristics by random sampling from a known probability distribution function.

municipal solid waste (MSW)
Refuse offering the potential for energy recovery. Technically, residential, commercial and institutional discards. Also included in the definition of municipal solid waste for purposes of this plan are non–hazardous processable by-products from manufacturing activities. Not included are combustible byproducts of the lumber, wood products, paper and allied products industries. These are considered separately as mill residue.

net billed plants
Refers to the 30 percent share of the Trojan Nuclear Plant, all of Washington Public Power Supply System's nuclear project 1 (WNP–1) and WNP–2, and 70 percent of WNP–3.

net billing
A financial arrangement that allowed Bonneville to underwrite the costs of electric generating projects. Utilities that owned shares in thermal projects, and paid a share of their costs, assigned to Bonneville all or part of the generating capability of these resources. Bonneville, in turn, credited and continues to credit the wholesale power bills of these utilities to cover the costs of their shares in the thermal resources. Bonneville then sells the output of the thermal plants, averaging the higher costs of the thermal power with lower cost hydropower.

nominal dollars
Dollars that include the effects of inflation. These are dollars that, at the time they are spent, have no adjustments made for the amount of inflation that has affected their value over time.

nonfirm energy
Energy produced by the hydropower system that is available with water conditions better than critical and after reservoir refill is assured. It is available in varying amounts depending upon season and weather conditions.

non–utility generator
A generic term for non–utility power plant owners and operators. Non–utility generators include qualifying facilities, small power producers and independent power producers.

option
As used in this plan, a project that has been sited, licensed and designed, but not yet constructed. Options are held in inventory until new resources are clearly needed.

overnight cost
Total of all direct and indirect project construction costs, including engineering, overhead costs, fees and contingency. Exclusive of costs attributable to interest and escalation incurred during construction.

Pacific Northwest (the region)
According to the Northwest Power Act, the area consisting of Oregon, Washington, Idaho, Montana west of the Continental Divide, and those portions of Nevada, Utah and Wyoming that are within the Columbia River Basin. It also includes any contiguous areas not more than 75 miles from the above areas that are part of the service area of a rural electric cooperative served by Bonneville on the effective date of the Act and whose distribution system serves both within and outside of the region.

Pacific Northwest Coordination Agreement
An agreement between federal and nonfederal owners of hydropower generation on the Columbia River system. It governs the seasonal release of stored water to obtain the maximum usable energy subject to other uses.

Pacific Northwest Utilities Conference Committee (PNUCC)
Formed by Pacific Northwest utilities to coordinate policy on regional power supply issues. PNUCC lacks contractual authority, but it does play a major role in regional power planning through its policy, steering, fish and wildlife, and lawyers committees, and the Technical Coordination Group. PNUCC publishes the Northwest Regional Forecast containing information on regional loads and resources.

peak capacity
The maximum capacity of a system to meet loads.

peak demand
The highest demand for power during a stated period of time.

penetration rate
The annual share of a potential market for conservation that is realized, as in "7 percent of the region's homes have been weatherized this year."

photovoltaic
Direct conversion of sunlight to electric energy through the effects of solar radiation on semi–conductor materials.

post–operational capital replacement costs
The cost of major equipment replacements occurring during the operating life of a project. In practice, these costs generally are capitalized (i.e., financed by debt or equity). For resource cost–effectiveness analyses, these costs are frequently treated as expenses.

preference
Priority access to federal power by public bodies and cooperatives.

present value
The worth of future returns or costs in terms of their current value. To obtain a present value, an interest rate is used to discount these future returns and costs.

public utility commissions
State agencies whose purpose is to regulate, among others, investor–owned utilities operating in the state with a protected monopoly to supply power in assigned service territories.

Public Utility Regulatory Policies Act of 1978 (PURPA)
Federal legislation that requires utilities to purchase electricity from qualified independent power producers at a price that reflects what the utilities would have to pay for the construction of new generating resources (see "avoided cost"). The act was designed to encourage the development of small–scale cogeneration and renewable resources.

qualifying facility (QF)
Qualifying facility is a power production facility that qualifies for special treatment under a 1978 federal law—Public Utility Regulatory Policies Act (PURPA). PURPA requires a utility to buy the power produced by the qualifying facility at a price equal to that which the utility would otherwise pay if it were to build its own power plant or buy the power from another source. A qualifying facility must generate its power using cogeneration, biomass, waste, geothermal energy, or renewable resources, such as solar and wind, and, depending on the energy source and the time at which the facility is constructed, its size may be limited to 80 megawatts or smaller. PURPA prohibits utilities from owning majority interest in qualifying facilities.

quantifiable environmental costs and benefits
Environmental costs and benefits capable of being expressed in numeric terms (for example, in dollars, deaths, reductions in crop yields).

quartile
The direct service industries load is divided into four quartiles. The top quartile is the portion of that load most susceptible to interruption.

R-value
A measure of a material's resistance to heat flow. The higher the R-value, the higher the insulating value.

real dollars
Dollars that do not include the effects of inflation. They represent constant purchasing power.

region
See "Pacific Northwest."

reliability
The ability of the power system to provide customers uninterrupted electric service. Includes generation, transmission and distribution reliability. The plan deals only with generation reliability.

renewable resource
Under the Northwest Power Act, a resource that uses solar, wind, water (hydro), geothermal, biomass or similar sources of energy, and that either is used for electric power generation or for reducing the electric power requirements of a customer.

reserve capacity
Generating capacity available to meet unanticipated demands for power, or to generate power in the event of outages in normal generating capacity. This includes delays in operations of new scheduled generation. Forced outage reserves apply to those reserves intended to replace power lost by accident or breakdown of equipment. Load growth reserves are those reserves intended for use as a cushion to meet unanticipated load growth.

resource
Under the Northwest Power Act, electric power, including the actual or planning electric capability of generating facilities, or actual or planned load reduction resulting from direct application of a renewable resource by a consumer, or from a conservation measure.

retrofit
To modify an existing generating plant, structure or process. The modifications are done to improve energy efficiency, reduce environmental impacts or to otherwise improve the facility.

sectors
The economy is divided into four sectors for energy planning. These are the residential, commercial (e.g., retail stores, office and institutional buildings), industrial and irrigation sectors.

simple payback
The time required before savings from a particular investment offset costs. For example, an investment costing $100 and resulting in a savings of $25 each year would be said to have a simple payback of four years. Simple paybacks do not account for future cost escalation, nor other investment opportunities.

siting agencies
State agencies with the authority for issuing permits to locate generating plants of defined types and sizes to utilities at specific locations.

siting and licensing
The process of preparing a power plant and associated services, such as transmission lines, for construction and operation. Steps include locating a site, developing the design, conducting a feasibility study, preliminary engineering, meeting applicable regulatory requirements, and obtaining the necessary licenses and permits for construction of the facilities.

space conditioning
Controlling the conditions inside a building in order to maintain human comfort and other desired environmental conditions through heating, cooling, humidification, dehumidification and air quality modifications.

sunk cost
A cost already incurred and therefore not considered in making a current investment decision.

supply curve
A traditional economic tool used to depict the amount of a product available across a range of prices.

surcharge
Under the Northwest Power Act, an additional sum added to the usual wholesale power rate charged to a utility customer of Bonneville to recover costs incurred by Bonneville due to the failure of that customer (or of a state or local government served by that customer) to achieve conservation savings comparable to those achievable under the Council's model conservation standards. Surcharges can range from 10 to 50 percent of a customer's bill.

System Analysis Model (SAM)
A computer model used by the Council to determine resource cost-effectiveness. SAM performs a detailed simulation of the Northwest generating system to estimate the cost associated with a specific set of loads and resources. It incorporates uncertainty associated with hydropower, thermal availability, resource arrival and load fluctuation due to economic cycles.

system cost
According to the Northwest Power Act, all direct costs of a measure or resource over its effective life. It includes, if applicable, distribution and transmission costs, waste disposal costs, end-of-cycle costs, fuel costs (including projected increases) and quantifiable environmental measures. The Council is also required to take into account projected resource operations based on appropriate historical experience with similar measures or resources.

thermal resource
A facility that produces electricity by using a heat engine to power an electric generator. The heat may be supplied by burning coal, oil, natural gas, biomass or other fuel, by nuclear fission, or by solar or geothermal sources.

tipping fee
The fee assessed for disposal of waste. This fee is used when estimating the cost of producing electricity from municipal solid waste.

transformer
A device for transferring energy from one circuit to another in an alternating-current system. Its most frequent use in power systems is for changing voltage levels.

transmission
The act or process of long-distance transport of electric energy, generally accomplished by elevating the electric current to high voltages. In the Pacific Northwest, Bonneville operates a majority of the high-voltage, long-distance transmission lines.

U-value
The measure of a material's ability to conduct heat, numerically equal to 1 divided by the R-value of the material.

Washington Public Power Supply System (WPPSS)
Municipal corporation and joint operation agency in Washington comprising representatives of public utility districts and municipal utilities. Based on power purchase contracts of its members or other utilities, WPPSS has the power to acquire, construct and operate facilities for the generation or transmission of electric power.

water budget
A means of increasing survival of downstream migrating juvenile fish by increasing flows during spring and early summer migrations. The water budget was proposed by the Council and is overseen by it in conjunction with the U.S. Army Corps of Engineers, the fishery agencies and Indian tribes, the Bonneville Power Administration and the Bureau of Reclamation.

watt
The electrical unit of power or rate of energy transfer. One horsepower is equivalent to approximately 746 watts.