Generating Resources[1]

Generating resources available for future development in the Pacific Northwest are described in this chapter. The chapter consists of two sections. The first is a discussion of the process of producing electricity including the major power generation applications - central station generation, cogeneration and distributed generation. The second section is a discussion of the primary energy resources available to the Pacific Northwest. Here, are described the most promising generating resource options for the Northwest. Central-station electric power generating technologies are described in additional detail in Appendix I. Additional material on cogeneration and distributed generation are in Appendix J.

ELECTRIC POWER GENERATION

Electricity is produced from naturally occurring primary sources of energy. These include the fossil fuels (coal, petroleum and natural gas), geothermal energy, nuclear energy, solar radiation, energy from processes driven by solar radiation (wind, hydropower, biomass production, ocean waves, ocean thermal gradients, ocean currents and salinity gradients) and tidal energy. The energy of these primary resources can be captured, converted to electricity and delivered to the end user by means of energy conversion systems. An energy conversion system may include fuel extraction, transportation and processing; electric power generation and transmission and distribution. Fuel extraction is collection of the primary energy resource. Natural gas wells, hydroelectric dams and solar concentrators are fuel extraction technologies. Though some energy sources such as wind and water can be used directly for power generation, many require processing before use for electricity generation. Fuel processing can be relatively simple, such as chipping of wood for firing a steam-electric power plant or complex, such as the refining of petroleum into fuels for electricity generation. Electric power generation technologies take many forms, depending upon the source of energy and the application. Most are thermal-mechanical devices that capture the energy contained in heated, compressed or moving fluids, and use this energy to drive an electric power generator. Exceptions include fuel cells, solid-state devices that convert the chemical energy of hydrogen into electric power and photovoltaics, solid-state devices that convert solar insolation to electric power.

Central-station Generation

Central-station generation comprises projects constructed with the principal objective of producing electric energy at the lowest cost consistent with environmental regulations and the anticipated operational role of the plant. Central-station projects comprise the majority of Northwest generating capacity including the coal, natural gas combined-cycle and nuclear bulk power generators, hydropower and utility-scale wind projects and a scattering of simple-cycle gas turbine and reciprocating engine peaking projects that operate during periods of high loads, short supply or high power prices. While some cogeneration and distributed generation will be constructed in the region during the 20-year planning period, the bulk of new generating capacity is expected to be central-station generation because of the strong competitive advantage enjoyed by these resources. Table 5-1 lists the central-station resources thought to have the greatest

[1] All costs and prices appearing in this chapter are expressed in constant year 2000 dollars. To convert from constant year 2000 dollars prices to constant year 2004 dollar prices used in the Executive Summary, Overview, and Chapters 6 and 7, multiply by 1.0776, which is a measure of the general inflation between 2000 and 2004.

potential for serving regional load growth. These are the generating resource options forecast to have reasonably competitive costs during the period of the plan, reasonable prospects for successful development and operation and sufficient quantity to measurably impact system costs and risks. These resources were included in the portfolio analysis described in Chapter 7. Resources listed in Table 5-2 are expected to play a more limited future role because of higher cost, limited supply or limited need for the services that they provide. These resources were not considered in the portfolio analysis but nonetheless may be attractive acquisitions under the right circumstances.

Planning assumptions for the generating resources of Tables 5-1 and 5-2 are summarized in Table 5-4 at the end of this chapter and described in additional detail in Appendix I.

Table 5-1: Generating resources and technologies with major future potential (year 2000 dollars)

Resource & Technology	Applications	Resource potential	Benchmark Cost[2] ($/MWh)	Status and Earliest Northwest Service
Coal(steam electric plant)	Baseload power supply	Sufficient to meet forecast regional load growth through 2025	$43	Commercial with some technical improvement potential; 2008 (permitted projects)
Coal (gasification combined-cycle plant no carbon separation)	Baseload power supply Co-product production	Sufficient to meet forecast regional load growth through 2025	$43	Early-commercial with technical improvement potential; 2011.
Natural gas (combined-cycle gas turbine power plant)	Baseload power supply Peak power supply Cogeneration	Sufficient to meet forecast regional load growth through 2025	Baseload $46 Peak incr. $200	Commercial with technical improvement potential; 2006 (partly-complete projects)
Natural gas (gas turbine generator)	Peak power supply Cogeneration	Sufficient for typical applications	Peak $250 Standby $89/kW/yr Cogeneration $47	Commercial with technical improvement potential; 2006
Natural gas (oil sands cogeneration)	Baseload power supply Cogeneration	~2000 MW capacity per DC circuit	$43	Commercial with technical improvement potential; 2011
Wind (utility-scale wind plant)	Intermittent baseload power supply	~ 5000 MW new capacity/1500 average megawatts of energy	$35 (1st 2500 MW) $43 (2nd 2500 MW) $33 (MT local)	Commercial with technical improvement potential; 2005.

[2] Benchmark cost assumptions (except as indicated): Levelized lifecycle cost, 2010 service, Mid-Columbia location, uniform financing (20% publicly-owned utility, 40 percent investor-owned utility, 40 percent independent), medium fuel price forecast, delivery to Mid-Columbia except simple-cycle gas turbines, reciprocating engines and photovoltaics are assumed to be local. Capacity factors: Baseload coal - 80%, Baseload gas - 65%, Peaking - 5%, Standby - 0%, Wind - 30%, Cogeneration - 90%; Solar -22%. CO_2 penalty, renewable energy production tax credit and green tag credits set at the means of the portfolio analysis, as applicable. Cogeneration costs based on fuel charged to power heat rate.

Table 5-2: Generating resources and technologies with moderate potential (year 2000 dollars)

Resource & Technology	Applications	Resource potential	Benchmark Cost[1] ($/MWh)	Status and Earliest Service
Wood residue (steam-electric)	Baseload power supply Cogeneration Waste disposal	1000 - 1700 aMW	$54 - 65 (w/cogen)	Commercial with technical improvement potential; 2006
Landfill gas (reciprocating engine)	Baseload power supply Waste disposal	100 - 200 aMW	$45	Commercial with technical improvement potential; 2006
Animal manure (reciprocating engine)	Baseload power supply Waste disposal	50 aMW	$56	Early-commercial with technical improvement potential; 2006
Pulping chemical recovery (steam-electric cogeneration)	Baseload power supply Cogeneration	280 aMW	$23	Commercial with technical improvement potential; 2006
Geothermal (flash steam)	Baseload power supply	Uncertain, possibly several hundred megawatts	$35[3]	Commercial technology with technical improvement potential; uncertain resource potential; 2009
Natural gas (reciprocating engine)	Peak power supply Standby power Cogeneration Distributed generation	Sufficient for listed applications	Peak $375 Standby $146/kW/yr Cogeneration $59	Commercial with some technical improvement potential; 2006
Solar (photovoltaics)	Remote power supply Distributed generation Intermittent baseload and grid support (long-term)	No effective limit	$250 (unshaped)	Commercial with technical improvement potential; 2005

[3] Benchmark cost assumptions: Levelized lifecycle cost, 2010 service, uniform financing (20% publicly-owned utility, 40 percent investor-owned utility, 40 percent independent),, delivery to the Mid-Columbia trading hub, 90 percent capacity factor, initial and replacement production and injection wells. Exclusive of possible green tag , production tax and investment credits. CO2 penalty set at the mean of the portfolio analysis.

Cogeneration

Cogeneration is the joint production of electricity and useful thermal or mechanical energy. Cogeneration involves the productive use of otherwise waste energy, thereby improving the overall energy efficiency of the production process. Production costs and environmental impacts can be lower than with than separate production of electricity and thermal products. Cogeneration comprises diverse combinations of resources, technologies and applications. Most existing installations in the Northwest are at industrial facilities and use natural gas, wood residues, biogas or spent pulping liquor as fuels. Technologies include gas turbine generators, combined-cycle power plants, steam-electric plants and reciprocating engine generator sets. The greatest potential appears to be at larger industrial and commercial installations. The smaller scale, technology and loads typical of the residential sector are not currently conducive to cogeneration cost-effectiveness. Cogeneration development is often conditioned on construction or renovation of the host facility.

Because of its generally small-scale, diversity, and unpredictable schedule, the Council did not evaluate cogeneration in the portfolio analysis. However, to provide a sense of the cost effectiveness of typical cogeneration projects, the Council assessed the cost of power from a range of proposed Northwest cogeneration projects. These projects were evaluated using proforma information supplied to the Council and the Council's forecast fuel prices and other assumptions of the portfolio analysis. The projects were as follows:

> 500 kW natural gas fired spark-ignition reciprocating engine generator with exhaust and jacket water heat recovery. Cogenerated hot water to supply a hospital hot water load. Natural gas supplied at commercial rates. Benchmark power cost [4] $73/MWh.
>
> 9 MW natural gas fired gas turbine generator with heat recovery steam generator. Cogenerated steam to supply an institutional space-conditioning load. No steam turbine generator. Natural gas supplied at commercial rates. Benchmark power cost [2] $94/MWh.
>
> 48 MW natural gas fired gas turbine generator with heat recovery steam generator. Cogenerated steam to supply an industrial process load. No steam turbine generator. Natural gas supplied at industrial rates. Benchmark power cost [2] $47/MWh.

Though these examples do not appear to be competitive with the central station generation projects of Table 5-1 solely on a wholesale power cost basis, environmental and local economic benefits, and offset transmission and distribution system costs may add sufficient value to these projects to make them desirable acquisitions.

Distributed Generation

Distributed generation is the production of power at or near electrical loads. Siting of generation at or near loads may be desirable for any of the following purposes:

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[4] Benchmark cost assumptions: Levelized lifecycle cost, 2010 service, uniform financing (20% publicly-owned utility, 40 percent investor-owned utility, 40 percent independent), medium fuel price forecast. Cost as delivered to local grid including $2/MWh ancillary service charge. 90 percent capacity factor. CO2 penalty set at the mean of the portfolio analysis, as applicable. Cogeneration costs are based on fuel charged to power heat rate.

- Standby power for critical loads such as hospitals, water supply, elevators and other services. Generally required by codes.

- Standby power for high value or uninterruptible production processes.

- Regulation of voltage or frequency beyond grid standards (premium power).

- Cogeneration service to industrial or commercial thermal loads conducive to supply by cogeneration.

- Power generation using an on-site byproduct suitable for use as a fuel.

- Local voltage support during periods of high demand (grid support).

- Reliability upgrade for system served by transmission or distribution susceptible to outages.

- Alternative to the expansion of transmission or distribution system capacity.

- Service to small or remote loads where more economic than line extension.

- Peak shaving to reduce demand charges or power purchase costs during times of high prices.

Distributed generation installations tend to be smaller than central-station plants, ranging from tens of kilowatts to about 50 megawatts in capacity. The benefits of distributed generation can best be secured with resources that are flexible in location and sizing such as smaller fossil fuel technologies, technologies using transportable biomass fuels and solar photovoltaics. Established distributed generation technologies include small gas turbine generators, reciprocating engine-generators, boiler-steam turbines, and solar photovoltaics. Emerging distributed generation technologies include microturbines and fuel cells, and possibly Sterling engines. The selection of a generating technology is very dependent upon the specific distributed generation application. Technologies having low initial cost, such as reciprocating engines are favored for applications with low expected load factors such as standby power. Higher efficiency and low emissions are more important with applications having higher expected load factors such as premium power and grid support applications. Reject heat characteristics are important for selecting technologies for cogeneration applications.

Because of the typically small size of distributed generation applications, the higher unit cost and lower efficiency of the equipment compared to central-station generation, and frequently higher fuel costs, distributed generation is rarely able to compete with the energy cost of grid-supplied electricity. It is the additional value imparted by the factors listed above that can make distributed generation attractive for specific applications. Because the value of distributed generation depends upon site-specific factors not amenable to regional analysis, distributed generation options were not included in the portfolio analysis. Additional information regarding distributed generation technologies is provided in Appendix J.

Impediments to development of cogeneration and distributed generation

The diversity of distributed generation and cogeneration technologies and applications and the importance of site-specific factors in determining the cost-effectiveness of these applications precluded the inclusion of distributed generation or cogeneration in the regional portfolio analysis described in Chapter 7. However, cost-effective cogeneration and distributed generation opportunities will surface over the period of the action plan. Impediments to the development of cogeneration and distributed generation, largely institutional in nature, may preclude the development of these opportunities. A cogeneration advisory group compiled the following list of impediments to the development of cost-effective distributed generation and cogeneration. These issues are generally common to the region and the action plan includes recommendations for resolution of these issues.

- Lack of routine processes for identifying potentially cost-effective customer-side cogeneration and small-scale renewable energy resources.
- Lack of commonly accepted cost-effectiveness criteria that accurately reflect the all costs and benefits including energy and capacity value, and the value of ancillary services, avoided transmission and distribution costs and losses and environmental effects.
- Disincentives to utility acquisition of power from projects owned or operated by others. The inability of investor-owned utilities to receive a return on power purchase agreements or investment in generation owned or operated by others generation creates an economic disincentive for securing these resources.
- Lack of uniform interconnection agreements and technical standards.
- Standby tariffs not accurately and equitably reflecting the costs and benefits of customer-side generation.
- Impediments to the sale of excess customer-generated power through the utility's transmission and distribution system.

ELECTRICITY GENERATING RESOURCES

The description of electricity generating resources of this section is organized alphabetically by primary energy resource. The technologies and applications listed in Tables 5-1 and 5-2 are described in the highlighted paragraphs within the corresponding energy resource section. The section organization and identification of the resources and technologies having significant potential as follows:

Energy Resource	Major Potential	Limited Potential
Biomass		Landfill gas energy recovery Animal manure energy recovery Chemical recovery boiler cogeneration Wood residue energy recovery
Coal	Steam-electric plants Gasification combined-cycle plants	
Geothermal		Hydrothermal power plants
Hydropower		Hydropower upgrades
Natural Gas	Gas turbine generators Gas turbine combined-cycle Alberta oil sands cogeneration	Reciprocating engine-generators Small gas turbine cogeneration (App J) Microturbine cogeneration (App J) Fuel cells (App J)
Nuclear		
Ocean Currents		
Ocean Thermal		
Petroleum		
Salinity Gradient		
Solar		Remote photovoltaics
Wave		
Wind	Central-station wind plants	

Hydrogen

The last several years have witnessed increasing interest in hydrogen as an energy source. Hydrogen has a very high heat value, 61030 Btu/lb, compared to common fuels such as natural gas (23,900 Btu/lb), gasoline (~20,400 Btu/lb) and fuel oil (~19,400 Btu/lb). The high heat value of hydrogen makes it potentially attractive for the transportation of energy. Hydrogen has a further advantage in that it combusts purely to water with no formation of carbon dioxide. Finally, hydrogen is the ideal feedstock for fuel cells since fuel cells require hydrogen as fuel (hydrocarbons such as natural gas must be reformed to hydrogen and carbon dioxide when used to operate fuel cells). Operation of prime movers such as gas turbines, boilers and Sterling engines on hydrogen fuel is also possible (though not fully perfected).

Unfortunately, elemental hydrogen is not present in significant quantity at or near the Earth's surface. The potential energy role of hydrogen is therefore that of an energy storage and transport medium, analogous to liquefied natural gas, rather than a primary energy resource. Hydrogen can be produced by electrolysis of water or reformation of hydrocarbons such as coal, natural gas or petroleum. Water electrolysis could be used where the primary energy input is non-hydrocarbon in nature, such as nuclear power, hydropower, wind or solar energy. Hydrocarbon reformation could be used where the energy input is a hydrocarbon such as coal, petroleum, natural gas or biomass. Because electrolysis and chemical reformation incur energy losses, the energy contained in the hydrogen product is less than the energy input to the process. The primary energy resource must be relatively inexpensive and difficult to use otherwise for the conversion to be attractive. It is likely that the earliest production of bulk hydrogen for energy purposes would be from coal or secondary hydropower. If costs can be reduced, hydrogen may ultimately be produced by electrolysis using electricity from large-scale intermittent sources such as solar or wind power or from nuclear power plants.

Hydrogen might eventually serve as a common energy transport medium, much like today's natural gas system. Potential benefits of the so-called hydrogen economy would be reduction of end-use carbon dioxide production and provision of transportation energy from non-petroleum sources. A hydrogen-based energy system would provide great primary resource flexibility, since hydrogen can be produced using renewable, nuclear or fossil energy sources. For fossil energy feedstocks, carbon separation and sequestration could occur at the hydrogen production plant, where likely to be more economic than at the end use. In addition, the system could shape the intermittent output of solar and wind power.

Formidable engineering problems must be resolved before widespread use of hydrogen as an energy transport and storage medium. Among these are the high hydrogen pressure needed to achieve reasonable energy density, the tendency of hydrogen to embrittle common fluid containment materials, high flame temperatures that promote NOx formation and compromise engine combustion path materials, and the containment problems resulting from the small molecular structure of hydrogen. Also needed is significant improvement to the economics and reliability of fuel cells, the most promising hydrogen energy conversion device. Finally, the transformation of the existing hydrocarbon and electrical-based energy production, storage and distribution system to one based on hydrogen will be economically and institutionally challenging.

Biomass

Biomass fuels include combustible organic residues of the production and consumption of food, fiber and materials. Biomass fuels can also be obtained from dedicated energy crops, however, in the Northwest food or fiber crops typically produce a greater return on investment. For this reason, residue fuels are likely to continue to provide the chief opportunities for the production of electricity from biomass. The chief residues available for electric power generation in the Northwest include forest residues, logging residues, mill residues, spent pulping liquor, municipal solid waste, agricultural field residues, the organic component of municipal solid waste, animal manure and landfill and wastewater treatment plant gas.

The quantity of residue material available for energy production depends on the level of economic activity, the "residue fraction" (amount of residue per unit of production producing the residue), and competing uses for the material. Production has generally declined in the forest products industry, has been stable in the other natural resources industries and has increased for municipal solid waste. Residue fractions (residue per unit output) have generally declined and competing uses have increased. An exception is forest residues. More aggressive forest health, fire control and commercial timber management could increase the availability of forest thinning residues.

Prices for biomass residues are set by the interaction of value for competing uses, cost of disposal and the cost of transportation. Fuel is the lowest value use for many of these materials, and competing uses will usually preempt the resource. For example, the pulp value of clean wood chips nearly always exceeds value as fuel. Environmental considerations generally require special disposal of residues and the cost of disposal will set a negative value on some materials. Transportation costs have an important influence on availability and delivered cost because of the low heat value and dispersed nature of many biofuels.

The estimated supply and price for the principal biomass fuels available for electric power generation in the Northwest given in Table 5-3.

Table 5-3: Estimated biofuel supply and cost (year 2000 dollars)

	Supply (TBtu/yr)	Undeveloped Potential (aMW)	Price ($/MMBtu)
Logging residue	27		$0.70 - $4.90
Forest thinning residue	39 - 125	310 - 980	$0.75
Mill residue	18	140	$0.0 - $2.05
Recovery boiler cogeneration	80	280	$0.0
Municipal solid waste/clean wood and paper fraction	64/45	365/350	($2.40 - $4.80)
Agricultural field residues	134	Not estimated	$2.40
Animal manure	--	52[5]	$0.00
Wastewater treatment plants	--	7[6]	$0.00
Landfill gas	17	175	$0.15
Hybrid cottonwood residue	3	25	$1.00
Dedicated hybrid cottonwood	Not estimated	--	$3.90

The most feasible uses of biofuels for electric power generation in the Northwest in the near-term are expected to be landfill gas energy recovery, animal manure energy recovery and chemical recovery boiler upgrades. While available in large quantities, the high cost of electric power generation using woody residues may constrain further development of this resource

[5] Energy and Environmental Analysis. Combined Heat and Power in the Pacific Northwest: Market Assessment. Prepared for Oak Ridge National Laboratory. July 2004. Dairies of 500 head, or more, poultry & swine. Excludes Montana.
[6] Ibid.

unless cogeneration opportunities are available to help reduce costs. Technical difficulties and seasonality of fuel availability are likely to preclude significant use of agricultural field residues for generation. Public opposition, high cost and established MSW disposal systems are likely to retard development of energy recovery from raw MSW, though most of the energy value of MSW can be recovered by separating the clean combustible fraction for use as fuel. A small, undeveloped potential for energy recovery exists at municipal wastewater treatment plants. Though technically feasible, the estimated cost of producing electricity from dedicated hybrid cottonwood exceeds $100/MWh, far greater than competing generating options. The wood is more valuable as a fiber crop.

Landfill Gas: Anaerobic decomposition of the organic matter in landfills produces a combustible gas consisting largely of methane and carbon dioxide. Gas production usually begins one or two years following waste placement and may last for several decades. Gas production rates vary greatly among landfills and are suppressed by water infiltration control, a normal practice for controlling leachate production. Landfill gas must be collected and combusted for safety reasons and to reduce its greenhouse gas potential[7]. Flaring is the conventional means of disposal, but electric power generation, upgrading to pipeline quality gas or use directly as a low-grade fuel are more productive uses. Most U.S. installations use reciprocating engine-generator sets, though microturbines are gaining favor in urban areas because of inherently lower NOx emissions. The undeveloped technical potential in the Northwest is estimated to be sufficient to generate about 175 average megawatts. Much of this potential is unlikely to be developed because of the high cost of electricity production at smaller landfills. The benchmark levelized cost of electricity production is about $49 per megawatt-hour. This cost is about 10 percent higher than the forecast cost of power from gas combined-cycle and other forms of bulk power production.   Incentives such as the recently expanded federal production tax credit and system benefit charge funds will encourage development of this resource. Development of landfill gas energy recovery projects creates a productive use of an otherwise wasted resource and may reduce greenhouse gas production to the extent that methane losses to the atmosphere are less than that incurred with flaring[8].

Animal manure: A combustible gas largely consisting of methane and carbon dioxide is obtained by anaerobic decomposition of animal manure. This can be used as a fuel for small-scale electric power generation installations. Waste heat from power generation equipment is used to speed the digestion process. Large-scale concentrated livestock operations such as feedlots and dairy farms and areas where animal waste is a water pollution issue offer the greatest potential. The potential from larger dairies, swine and poultry operations has recently been estimated to be 52 average megawatts (excluding Montana). The benchmark cost of electricity production is $60 per megawatt-hour. While much greater than the forecast wholesale cost of power from gas combined-cycle and other bulk power sources the cost may be competitive with the retail electricity cost to the host facility. Moreover, an energy recovery system can be a component of an integrated manure disposal system to resolve environmental issues. A system may also qualify for system benefit funds or future federal production tax credits, if the scope of these is extended to biomass residues as proposed.

[7] Methane has about 21 times the greenhouse warming potential than the carbon dioxide product of its combustion.
[8] Landfill gas electricity generation is likely to lead to somewhat greater, and accelerated carbon dioxide production than flaring. However, methane losses in flaring of a couple of percent may lead to a much greater greenhouse gas impact because of the greater warming potential of methane.

Pulping Chemical Recovery: Chemical recovery boilers are used to recover the chemicals from spent pulping liquor used in chemical pulping of wood. Lignins and other combustible materials in the spent liquor create the fuel value. Recovery boilers, usually augmented by power boilers fired by wood residue, natural gas or other fuels, supply steam to the pulping process. More efficient use of the fuel is possible by producing the steam at high pressure, running it through a steam turbine generator and extracting process steam at the desired pressures. When the Fourth Power Plan was prepared, 8 of the 19 operating pulp and paper mills in the Northwest were not equipped for cogeneration in this manner. Estimates prepared for that plan indicated that an additional 280 average megawatts of electric power could be produced from installation of cogeneration equipment at recovery boilers not having such equipment. This estimate has not been updated since the Fourth Plan; however no new chemical recovery boiler cogeneration has been reported. The representative levelized cost of electricity production of a pulp and paper mill cogeneration retrofit is $24 per megawatt-hour with credit for steam. This is lower than the cost of electricity from any other new generating option. Limited capital availability and the economic conditions in the industry may account for the lack of development of this resource.

Wood Residue: Wood residues encompass forest residues, logging residues, mill residues and the clean woody fraction of municipal solid waste (urban wood waste and construction debris). Though production of logging and mill residue has declined in the Northwest over the past two decades, stabilization and possible expansion of the supply of logging and mill residue can be expected as forest recovery permits expansion of logging. The supply of forest thinnings could increase from more aggressive commercial forest management, forest health restoration efforts and wildfire control. The woody fraction of municipal solid waste is expected to increase in quantity with economic and population growth. Conventional steam-electric plants with or without cogeneration are likely to remain the chief technology for electricity generation using wood residues. The undeveloped electricity production potential of wood residue in the Northwest is potentially large, but uncertain because of the unknown future availability of forest thinnings. The Fourth Power Plan estimate was based on opening of one third of degraded National Forest lands to thinning on a 20-year cycle. This estimate yields a total wood residue supply of 132 to 218 TBtu/year. This amount would support the production of 1040 to 1720 average megawatts. The representative levelized cost of electricity production ranges from $58 to $70 per megawatt-hour, with credit for cogenerated steam. This cost is much greater than the forecast wholesale cost of power from gas combined-cycle and other forms of bulk power production and only marginally competitive with retail rates. This suggests that the resource may not be fully developed without financial incentives. These could include an extension of the federal production tax credit to biomass residues, subsidization of forest health recovery efforts or aggressive greenhouse gas control policy (wood residue is carbon dioxide neutral at sustainable harvest levels). A combination of these would likely be needed to achieve cost-effectiveness.

Coal

Coal is the solid metamorphosed residue of ancient vegetation, found in strata ranging in thickness from several inches to tens of feet, at depths of tens to hundreds of feet. Coal consists of a high percentage of carbon and lesser amounts of hydrogen, sulfur and other elements in variable proportions. The energy content is chemical, and is recovered by combustion. Coals are classified by rank, ranging from lignite, sub-bituminous, bituminous to anthracite, corresponding to the degree of metamorphosis. Northwest coals are predominantly sub-bituminous and lignite, though bituminous coals are present in adjacent areas. A typical Powder River basin sub-bituminous coal has a moderate heat value (e.g. 8750 Btu/lb) and low sulfur (e.g. 0.4%) content. Near-surface coal is mined by removing the overburden, excavating the coal and replacing the overburden. Underground mines are used to recover deep-lying coal. Coal preparation includes crushing, sizing, washing to remove impurities and drying.

Abundant supplies of low sulfur coal are found in western North America. Production costs are low enough to permit coal to be shipped economically hundreds of miles by rail or thousands of miles by barge to power plants nearer electrical load centers. Alternatively, electricity from plants located near the mine mouth can be transmitted economically hundreds of miles to load centers. The principal coal resources available to the Northwest include the Powder River basin fields of eastern Montana and Wyoming, the East Kootenay fields of southeastern British Columbia, the Green River basin of southwestern Wyoming, the Uinta basin of northeastern Utah and northwestern Colorado and extensive deposits in Alberta. Coal could also be obtained by barge from the Quinsam mines of Vancouver Island or the Chuitna mines of Alaska. The availability of coal from fields near Centralia, Washington beyond that needed to fire the existing Centralia power plant appears insufficient to fuel additional plants.

Sufficient coal is available to the region to support all electric power needs for the 20-year planning horizon of this plan. Improvements in mining and rail haul productivity and stagnant consumption have resulted in declining production costs (in constant dollars) over the past couple of decades. Carbon dioxide control policy and overseas demand are the important uncertainties affecting future coal prices. With no improvement in coal-fired power generation technology, carbon dioxide penalties would likely depress demand and prices. However, if advanced technologies for separating carbon for sequestration become available, domestic and overseas demand and prices are likely to remain stable or even increase. Western mine mouth coal is forecast at $0.51/MMBtu and stable in year 2000 dollars in the medium case (Chapter 2).

Coal is the major source of electric power in the United States as a whole, and the second largest component (23 percent) of the western power supply. In recent decades, the economic, technical and environmental attributes of combined-cycle gas turbines eclipsed coal-fired steam-electric technology. Less than 500 megawatts of coal capacity entered service on the western grid between 1990 and 2004. However, the prospects for coal are changing. The capital cost of conventional coal steam-electric plants declined about 25% in constant dollars since the early 1990s with little or no sacrifice to electrical efficiency or reliability. This is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction, shortened construction schedule, and increased market competition. This, plus persistently high natural gas prices have reinvigorated the competition between coal and natural gas. This is evidenced in the Northwest by construction of a small 113-megawatt coal-fired plant at Hardin, Montana and plans for a 250-megawatt unit near Great Falls.

Coal-fired steam electric plants: Coal-fired power plants constructed within the next several years are likely to employ conventional steam-electric technology. This is proven technology and plant cost, design and methods of construction and operation are well understood. Steam technology, though mature, will continue to evolve and features such as fluidized bed boilers and supercritical steam cycles are being adopted (See additional discussion in Appendix I). Public concerns regarding air emissions are likely to restrict siting to locations remote from major load centers. Transmission will therefore likely remain an important constraint on the construction of new plants. The reference plant is a 400-megawatt pulverized coal-fired unit with a subcritical steam cycle, co-located with several similar units to achieve economies of scale. The plant is assumed to be equipped with a full suite of criteria air emission[9] control equipment including activated charcoal injection for additional reduction of mercury emissions. The benchmark levelized cost of electricity production from a plant located in the Mid-Columbia area is $43 per megawatt-hour.

Coal-fired gasification combined-cycle plants: Increasing concerns regarding mercury emissions and carbon dioxide production are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. Under development for many years, pressurized fluidized bed combustion and coal gasification apply efficient combined-cycle technology to coal-fired generation (see additional discussion in Appendix I). This reduces fuel consumption, improves operating flexibility and lowers carbon dioxide production. Coal gasification technology offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels or other petrochemicals. The low air emissions of coal gasification plants might open siting opportunities nearer load centers.

Coal gasification combined-cycle plants were selected as representative of advanced coal power generation technologies because of incipient commercialization and potential for economical control of mercury and carbon separation. Designs with and without carbon separation were characterized. The plant without carbon separation is a 425 MW integrated coal-fired gasification combined-cycle plant using a pressurized oxygen-blown gasifier. Not included are optional hydrogen or liquid fuel co-production facilities. Though base year capital costs are 13 percent greater than the steam-electric plant because of increased complexity, this is offset by a 17 percent greater electrical efficiency and a forecast higher rate of technological improvement. The construction period, based on demonstration plant experience is somewhat longer, 48 months vs. 42 months for the conventional plant, however the increased modularity of these plants should eventually allow greater factory fabrication, improved quality and shorter lead-time. Characterized as requiring further demonstration in the draft plan, recent developments indicate that the technology is entering the early commercial stage. As discussed more fully in appendix I, vendor and architect engineer consortiums have formed to provide wraparound plant performance warranties and full design, build operate services. In addition, several utilities and independent developers have announced intent to construct coal gasification power generation capacity. The benchmark cost of electricity production from a plant located in the Mid-Columbia area is $43 per megawatt-hour. This cost is expected to decline as the technology matures.

[9] Emission controlled under the Clean Air act of 1990. These include sulfur dioxide, nitrogen oxides, particulates, hydrocarbons and carbon monoxide.

The plant with carbon separation is of the same general design as the first plant, but would be equipped for capture and compression (for pipeline transport) of 90% of its carbon dioxide production. Such a plant would likely be located in the eastern portion of the region to access geologic formations suitable for carbon sequestration. Net power output is reduced to 401 MW because of the additional energy required for carbon dioxide separation and compression. Capital costs are 22 percent higher. Though the carbon dioxide separation and compression technology assumed for this plant has been commercially proven, further testing of sustained gas turbine operation on hydrogen fuel would be required. In addition, the suitability of promising geologic formations in the Northwest for carbon sequestration remains to be demonstrated. Deep saline aquifers potentially suitable for carbon sequestration are present in eastern Montana. Further discussion of carbon sequestration is provided in Appendix K.

Geothermal

Current technology does not permit tapping the subcrustal zone that provides the ultimate source of geothermal energy. Geothermal development is presently feasible only where geologic conditions have created a near-surface heat source supporting an overlying hydrothermal circulation system. A promising resource for geothermal electricity generation requires temperatures of about 300^{o} Fahrenheit or higher, water, and fractured or highly porous rock, coincidental at depths of about 10,000 feet, or less.

Several geologic structures found in the Northwest are thought to have potential for geothermal electricity generation. Crustal spreading in the Basin and Range area of southeastern Oregon and southern Idaho has produced deep vertical faults parallel to the valleys and ranges of this geologic province. Circulation within these faults brings heated water towards the surface. Basin and Range geothermal resources are used for electric power generation in Nevada, Utah and eastern California. Recent proposals for geothermal development in southern Idaho, if successful, would be the first commercial development of Basin and Range resources in the Northwest.

The Cascade Range is an active volcanic arc derived from subduction of oceanic plates. Earlier models of Cascades geology suggested the presence of large geothermal potential, possibly as much as several hundred thousand megawatts. More recent research suggests that while local high-temperature hydrothermal systems may exist in the Cascades, geothermal potential suitable for electric power generation outside of these areas is likely to be limited or absent. Structures with geothermal potential include the magma underlying the stratovolcanos (Mounts Baker, Adams, Rainier, Hood, St. Helens, Shasta and Glacier Peak), shallow magmatic intrusions underlying the Three Sisters and Mount Lassen composite centers, low to intermediate temperature hydrothermal systems originating from the remaining portion of the Crater Lake/Mt Mazama magma chamber and intrusive bodies with known high temperature systems present at the Newberry Volcano and Glass Mountain/Medicine Lake shield complexes. The latter are the only Cascades structures offering geothermal potential not largely precluded by land use conflicts. They may be capable of supporting several hundred megawatts and possibly more of geothermal generation.

An intermediate-temperature hydrothermal system, developed for space heating exists at Klamath Falls, Oregon. Higher-temperature fluids may exist at depth. Low and intermediate temperature thermal features of the Snake River Plain are thought to be relics of past influence of the "hot spot" now underlying Yellowstone National Park. The Island Park Caldera west of Yellowstone may hold a high-temperature resource, but lease applications were withdrawn because of concerns regarding effects on the hydrothermal features of the Park.

Because of the highly uncertain and apparently limited resource potential, geothermal power generation was not considered in the portfolio analysis of this plan. Efforts called for in the 1991 Power Plan to develop geothermal pilot projects failed to produce a viable project except at Glass Mountain where a resource had been earlier confirmed. Recent developments, including announced projects in southern Idaho, successful completion of a test well at Meager Mountain in British Columbia and extension of a federal production tax credit to geothermal projects suggest resurgence in interest in geothermal development. This plan calls on utilities to acquire renewable energy projects if cost-effective opportunities rise to encourage the development of geothermal projects.

Geothermal Power Plants: Commercially available geothermal generating technologies include dry steam, flashed steam and binary cycle power plants. Dry steam plants are used with vapor-dominated resources such as The Geysers in California. No vapor-dominated resources are known to exist in the Northwest. Flashed-steam plants or binary-cycle technologies would be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. Flashed-steam plants are used with resources of about 300^{o} Fahrenheit, or greater. In these plants, the pressurized geothermal fluid is brought to the surface by means of wells and piped to a central power plant. The fluid is partially depressurized, forming steam used to drive a steam turbine generator. The residual liquid and steam condensate is reinjected into the geothermal reservoir. Binary cycle technology is used for lower temperature hydrothermal reservoirs. The geothermal liquid is brought to the surface using wells, and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine-generator, condensed and recycled to the heat exchanger. The cooled geothermal fluid is reinjected to the geothermal reservoir.

The limited cost information on geothermal plants suggests that costs have declined significantly in the past decade and a half, particularly for flash technology. Factors include increased competition, crossover oil and gas exploration and drilling technology, general improvements to plant equipment and design and more efficient engineering and construction. The example plant is a 50-megawatt double flash project located at a high quality 450^{o} F hydrothermal system in the inland Northwest within 25 miles of a suitable transmission interconnection. The benchmark cost[3] of electricity production is $35 per megawatt-hour. This cost includes initial and replacement production and injection wells. Because of limited cost information, now several years old and the considerable influence of reservoir and site conditions, this cost estimate should be regarded as highly uncertain. Also, in recent years, geothermal plants have developed nearly exclusively by independent developers. This would increase financing costs above those assumed for the benchmark cost.

Hydropower

Topographic relief and high levels of precipitation, much of which falls as snow, produce the sustained large volumes of annual runoff and vertical drop that create the great hydropower resource of the Pacific Northwest. The theoretical hydropower potential in the Pacific Northwest has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Hydropower is by far the most important generating resource in the Pacific Northwest, providing about two-thirds of the generating capacity and over three quarters of electric energy on average.

Though the remaining theoretical hydropower potential of the Northwest is large, most economically and environmentally feasible sites have been developed. The remaining opportunities, though numerous, are for the most part small-scale and relatively expensive. Among these are addition of generating equipment to irrigation, flood control and other non-power water projects, incremental additions of generation to existing hydropower power projects with surplus streamflow, and a few projects at undeveloped sites. In its Fourth Plan, the Council estimated that about 480 megawatts of additional hydropower capacity is available for development at costs of 9.0 cents per kilowatt-hour, or less. This capacity could produce about 200 megawatts of energy on average. However, few projects are expected to be constructed because of the high cost of developing most of the remaining feasible sites and the complex and lengthy licensing process It appears unlikely that new hydroelectric development will be able to offset the loss of capacity and energy from expected removal of several older environmentally damaging projects.

Hydropower upgrades: More promising are potential improvements to existing hydropower projects, yielding additional capacity and energy. Many existing projects date from a time when the value of electricity was lower and equipment efficiency less than now and it is often feasible to undertake upgrades such as advanced hydro turbines, generator rewinds and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy. Earlier estimates by Bonneville suggested that over one hundred megawatts of additional energy could be secured cost-effectively through hydropower upgrades. Though numerous upgrades have since been completed, better technology and higher electricity values are likely to have extended the undeveloped potential. This plan calls on utilities to acquire renewable energy projects, including hydropower upgrades as cost-effective opportunities rise.

Natural gas

Natural gas is a naturally occurring combustible gas, predominantly methane, with lesser amounts of other light hydrocarbons, carbon dioxide, nitrogen and helium. Natural gas is found in porous geologic structures, often in association with petroleum or coal deposits. Raw natural gas is recovered by means of wells and processed to remove condensable hydrocarbons, carbon dioxide, water and impurities. The resulting product is odorized and compressed for transportation by pipeline to markets.

Though natural gas has been produced in central Montana and to a very limited extent in local areas west of the Cascades, the Pacific Northwest is not regarded as having significant future gas supplies. However, the region has excellent pipeline access to important western North American natural gas producing areas including the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain basin of Wyoming and Colorado and the San Juan basin of New Mexico.

Low natural gas prices and development of efficient, low-cost, environmentally attractive gas-fired combined-cycle power plants led to a surge of construction early in the 1990s and again during the energy crisis of 2000 and 2001. Natural gas power plants now represent about 13 percent of Northwest generating capacity. Gas prices have since risen due to a decline in well productivity and loss of the Northwest's historic gas market advantage by expansion of pipeline transportation from Alberta to eastern markets. Interest is rising in securing access to overseas supplies of natural gas via liquified natural gas (LNG) transport and in the longer-term, LNG imports are expected play an important role in determining marginal gas prices. Over forty new LNG terminals have been proposed for North America, including one in Oregon on the lower Columbia River.

The estimated ultimate potential of gas supply areas serving the Northwest is about 22 years at current production rates. New sources of supply including "Frontier Gas" from the Alaskan North Slope and the McKenzie Delta, unconventional sources such as coal bed methane and tight sands, U.S. and Canadian offshore fields and LNG are expected to make up shortfalls and to set marginal prices in the long-term. Natural gas delivered on a firm basis to an Eastside power plant is forecast to decline on average from $5.50/MMBtu in 2005 to $4.03/MMBtu in 2015 as new sources of supply are developed. Average prices are then expected to increase slowly to $4.25/MMBtu by 2025 (year 2000 dollars). Westside prices are expected to run about 20 cents higher. Unpredictable periods of price volatility are likely to occur during this period. The natural gas price forecast is further discussed in Chapter 2.

Natural gas and petroleum are the most flexible of the primary energy resources in terms of technologies and applications. Generating technologies that can be fuelled by natural gas include steam-electric plants, gas turbine generators, gas turbine combined-cycle plants, reciprocating engine generators and fuel cells. Applications run the gamut - baseload, load following, peaking , cogeneration and distributed generation. The applications discussed here - gas turbine generators, combined-cycle plants and Alberta oil sands cogeneration - are those that might play a major role in the near to mid-term. These and other central station natural gas technologies are discussed in Appendix I. Representative natural gas cogeneration options and distributed generation applications using natural gas are discussed in Appendix J.

Natural gas-fired gas turbine generators: A gas turbine generator is a compact, modular generating plant with flexible startup and load following characteristics. A wide range of unit sizes is available, from less than 1 to greater than 170 megawatts. Gas turbine power plants (also called simple-cycle gas turbines or combustion gas turbines) are available as heavy-duty industrial machines specifically designed for stationary applications, or as "aeroderivative" machines - aircraft engines adapted to stationary applications. Sub-megawatt gas turbine generators (microturbines) are available for distributed generation applications. Low to moderate capital costs, superb operating flexibility and moderate electrical efficiency make gas turbine generators attractive for peaking and grid support applications. Cogeneration loads can be served by addition of a heat recovery steam generator. Gas turbine generators also feature highly modular construction, short construction time, compact size, low air emissions and low water consumption[10]. Because of the ability of the hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a somewhat minor element of the Northwest power system, comprising about 3% of generating capacity. Most are pure simple-cycle units for peaking and reserve service, and some are industrial cogeneration.

The reference simple-cycle plant consists of two 47-megawatt aeroderivative gas turbine generators. Fuel is pipeline natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Costs are representative of an installation at an existing gas-fired power plant site. Because of relatively low efficiency compared to combined-cycle plants, power-only simple-cycle plants would be unlikely to operate as a baseload resources. The benchmark electricity cost in peaking service (5 percent capacity factor) is $250/MWh, expensive, but comparable to other peaking generation if infrequently dispatched. Industrial-grade gas turbines are available at lower capital cost but at reduced efficiency and increased unit size. The earliest availability of new capacity is 2006.

Natural gas fired gas turbine combined-cycle power plants: Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam turbine generator. Use of the exhaust heat greatly increases the plant efficiency at little additional capital cost. Cogeneration steam loads can be served (at some loss of electricity production) by bleeding steam from the heat recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained by enlarging the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing).. Because the resulting capacity increment operates at lower electrical efficiency than the base plant it is usually reserved for peaking operation. Gas-fired combined-cycle plants have been the bulk power generation resource of choice since the emergence of efficient and reliable gas-turbine generators in the early 1990s. 64 percent of the 6840 megawatts of generation constructed in the Northwest since 1990 has been gas-fired combined-cycle capacity and these plants now comprise about 10 percent of regional capacity. Reasons for this popularity include an extended period of low natural gas prices, reliable and efficient equipment, low capital costs, short lead-time, operating flexibility and low air emissions. Because of these attributes, natural gas combined-cycle plants are among the key resources considered in the development of this plan. The low carbon content of natural gas and high electrical efficiency reduces the sensitivity of these plants to possible carbon dioxide control costs. Higher natural gas costs, however, have dimmed the attractiveness of the technology.

The reference plant is comprised of two "F-class" gas turbine generators and one steam turbine generator. The baseload capacity is 540 megawatts with an additional 70 megawatts of power augmentation. Fuel is pipeline natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for

[10] Larger amounts of water are required for cogeneration units, air inlet evaporative cooling or water injection for power augmentation or nitrogen oxide control.

CO and VOC control.[11] Condenser cooling is wet mechanical draft. The benchmark electricity cost is $46/MWh. Units in the region for which construction has been suspended could be completed by 2006. No limits were placed on the availability of additional new capacity during the planning period.

Alberta oil sands cogeneration: A special case of natural gas generation is cogeneration at the oil sands deposits of Northern Alberta. The oil sands contain the largest petroleum deposits outside the Middle East; these consist of bitumen embedded in a sandy matrix. The viscous bitumen is extracted by heating in-situ with steam, or if mined, with hot water. The extracted bitumen is processed into a synthetic crude oil. Rising oil prices have made the process economic and production is expected to expand rapidly in coming years. The steam can be produced using natural gas-fired boilers or more efficiently by cogeneration using natural gas-fired simple-cycle combustion turbines with exhaust heat recovery steam generators. Though approximately 2000 megawatts of oil sands cogeneration is in service, additional development is constrained by limited transmission access to electricity markets. A 2000-megawatt DC intertie from the oil sands region to the Celilo converter station near The Dalles has been proposed as a means of opening markets for oil sands cogeneration. The transmission could be energized as early as 2011. Preliminary estimates suggest that power from oil sands cogeneration could be delivered to the Northwest at a levelized cost of $43/MWh. While only slightly lower than the comparable cost of electricity from a new gas fired combined cycle plant in the Mid-Columbia area, the higher electrical efficiency of oil sands cogeneration may offer better protection from natural gas price volatility. Moreover, a gasification process for deriving fuel gas from oil sands processing residuals is available. This alternative fuel could further isolate oil sands cogeneration from natural gas price risk. The incremental carbon dioxide production of cogeneration is less than for stand-alone gas-fired generation, reducing the cost of possible future carbon dioxide control measures. Development of the proposed intertie, however, would present a major challenge. Transmission siting and permitting efforts in the U.S., especially for new corridors, has proven difficult. Subscription financing is proposed. While effective for financing incremental natural gas pipeline expansions, subscription for financing large-scale transmission expansions is untested. Finally, the 2000-megawatt capacity increment is likely too large for the Northwest to accept at one time. Some means of shortening commitment lead-time and phasing project output would improve prospects for development.

Nuclear

A nuclear power plant produces electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium and plutonium. Commercial nuclear fuel is comprised of a mixture of two isotopes of natural uranium - about 3 percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron. Reactors using thorium and "bred" plutonium have been developed in anticipation of eventual shortages of natural uranium. However, it appears that the industry can continue to rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast at $0.40/MMBtu through period of the plan.

[11] Volatile Organic Compounds

Nuclear fuel production for light water reactors begins with concentrating the U-235 fraction of natural uranium to the desired enrichment. The enriched uranium is reacted with oxygen to produce uranium oxide. This is fabricated into pellets, which are then stacked and sealed into zirconium tubes to form a fuel rod. Fuel rods are assembled into fuel assemblies - bundles of rods arranged to accommodate neutron absorbing control rods and to facilitate removal of the heat produced by the fission process. Nuclear fuel is a highly concentrated and readily transportable form of energy, freeing nuclear power plants from fuel-related geographic constraints.

Operating nuclear units in the United States are based on light water reactor technology developed in the 1950s. Future nuclear plants are expected to use advanced designs employing passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. Though preliminary engineering is complete, construction and operation of a demonstration project is required before the technology can be considered commercial. Electricity industry interest in participating in one or more commercial-scale demonstrations of advanced technology is increasing. But even if demonstration plant development moves ahead in the next several years, lead times are such that advanced technology is unlikely to be fully commercial until about 2015. This suggests the earliest operation of fully commercial advanced plants would be around 2020. Also needed for public acceptance of new nuclear development is a fully operational spent nuclear fuel disposal system. Though spent fuel disposal technology is available and the Yucca Mountain site is under development, the timing of commercial operation remains uncertain.

Nuclear plants could be attractive under conditions of sustained high natural gas prices and aggressive greenhouse gas control. Other factors favoring nuclear generation would be failure to develop economic means of reducing or sequestering the CO2 production of coal based generation, and difficulty expanding transmission to access new wind or coal resources. Because the earliest possible deployment of commercial units using advanced nuclear technology is late in the planning period, this technology was not further evaluated in this plan. The expected characteristics of an advanced nuclear unit are described in Appendix I.

Ocean Currents

The kinetic energy of flowing water can be used to generate electricity by water-current turbines operating on similar principals to wind turbines. Conceptual designs and prototype machines have been developed and arrays of current turbines have been recently proposed for New York City's East River and San Francisco's Golden Gate. Turbine energy yield is very sensitive to current velocity and little electrical potential is available from the weak and ill-defined currents off the Northwest coast and in the Strait of Juan de Fuca. Tidal currents of 3 to 8 knots occur locally in Puget Sound and estuaries along the Oregon and Washington coast. Because these velocities are attained for only an hour or two on the run of the tides and are unlikely to provide an economic source of energy in the foreseeable future.

Ocean Thermal Gradients

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depths of several thousand feet.

Megawatt-scale OTEC technology has been demonstrated in Japan and Hawaii, but the technology is inefficient (2 - 3%) and requires a temperature differential of about 20^o C (36^{o}F). Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12^{o}C (0 - 20^{o}F) precluding operation of OTEC technology.

Petroleum

Petroleum is comprised of liquid hydrocarbon compounds thought to originate from the buried remains of marine organisms. These materials migrated through porous geologic formations and accumulated below folded impermeable sedimentary formations. Crude petroleum is extracted by means of wells and refined using distillation, cracking, hydrotreating and other processes into a wide variety of products. Among these are propane, distillate and residual fuel oils, which can be used as fuels for electric power generation.

Petroleum fuels are universally available at prices largely determined by the global market. Fuel oil prices are expected to decline from current highs and over the term of this plan, upward pressure on petroleum fuel prices from increasing demand in developing countries should be offset by relatively low and constant production costs. The prices of industrial distillate and residual fuel oils are forecast to be $4.43 and $7.69/MMBtu, respectively, in 2005 (year 2000 dollars). In the medium case, these prices are forecast to decline through 2010 then stabilize on average with likely periods of short-term volatility. Residual and distillate prices in 2025 are forecast to be $3.99 and $7.12/MMBtu, respectively (Chapter 2). . In general, the cost of petroleum-derived fuels is too high for bulk electric power generation. Fuel oil is used as a backup fuel, for peaking or emergency service power plants and for power generation in remote areas.

Salinity Gradients

Energy is released when fresh and saline water area mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies could be captured and converted to electricity. Concepts that have been advanced for the generation of electric power from salinity gradients include osmotic hydro turbines, dilytic batteries, vapor pressure turbines and polymeric salinity gradient engines. These technologies are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between fresh water and seawater. Although the theoretical resource potential in the Northwest is substantial, many years of research, development and demonstration would be required to bring these technologies to commercial availability.

Solar

The amount of solar radiation reaching the ground and available for conversion into electricity is a function of latitude, atmospheric conditions and local shading. The resource potential in the Northwest is greater east of the Cascades, with less annual cloud cover. Latitude and shading are influential and the most promising areas lie in the southern portion of the region, in open and flat terrain. The best areas are the inter-mountain basins of south-central and southeastern Oregon and the Snake River plateau of southern Idaho. On an annual average, these areas receive about 75 percent of the insolation received in Barstow, California, one of the best U.S. sites.

The strong summer seasonality of the Northwest solar resource suggests that while the solar resource has potential for serving local summer-peaking loads, such as irrigation and air conditioning, it is less suitable for serving more general regional loads. There have been no comprehensive studies of site suitability for development, though in theory, there is sufficient solar resource to support all regional electrical requirements.

Solar energy can be converted to electricity using solar thermal technologies or photovoltaics. Solar thermal technologies remain very costly and are potentially suited to bulk power generation. The most promising application of solar power during the near-term appears to be small-scale photovoltaic installations servicing to small loads isolated from the grid. Though flat in recent years, the reduction in photovoltaic costs over the past several decades has been rapid compared to other power generation technologies.

Photovoltaics: Photovoltaics is solid-state conversion of sunlight to electricity. The technology is commercially established and widely employed to serve small remote loads for which it is too costly to extend grid service. Power output is intermittent and battery storage or auxiliary power is required for loads demanding a constant supply. Because no combustion or other chemical reactions are involved, photovoltaic power production is emission free. No water is consumed other than for periodic cleaning. Costs are presently too high for economic grid-connected electricity production. A representative cost of unshaped busbar power from rooftop grid-connected photovoltaic systems is currently $250 megawatt-hour. If costs continue to decline at the average historical rate, by 2025 central station plants might produce unshaped power at the busbar for $45 per megawatt-hour; a cost competitive with other central station technologies. However, photovoltaic cost reduction has stagnated in recent years and technical breakthroughs may be required to achieve the cost reductions required for large-scale deployment. Because of the prospects of a continuing high differential between photovoltaic electricity costs and market value, there appears little that the region can do to promote cost reductions for this globally traded product beyond seeking out near-economic niche applications and to encourage federal research.

Tidal Energy

Tidal energy originates from the loss of the earth's rotational momentum due to drag induced by gravitational attraction of the moon and other extraterrestrial objects. Tidal energy can be captured and converted to electricity by means of hydroelectric "barrages" constructed across natural estuaries. These admit water on the rising tide and discharge water through hydroturbines on the ebb. The key requirement is a large mean tidal range, preferably 20 feet or more. Suitable sites with tides of this magnitude occur only in a few places worldwide where the landform amplifies the tidal range. Tidal hydroelectric plants have been developed in some of these locations. Environmental considerations aside, the development of economic tidal hydroelectric plants in the Northwest appears to be precluded by insufficient tidal range. Mean tidal ranges in the Pacific Northwest are between 4.5 and 10.5 feet, with the greatest mean tides found in bays and inlets of southern Puget Sound.

Wave Energy

Recently proposed West Coast demonstration projects have sparked interest in ocean wave electricity generation. Waves are produced by the action of wind blowing over water. The wave energy of the mid- and North Pacific coasts is the best of any coastal area of the United States, with estimated average wave power at near-shore locations ranging from six to nine kilowatts per meter of wave crest. Offshore, the estimated power is 37 to 38 kilowatts per meter of wave crest. The theoretical wave power potential of the Washington and Oregon ocean coast is approximately 3400 - 5100 megawatts for near-shore sites and 21,000 megawatts for offshore sites. Wave power devices are expected to have an efficiency of at least 12 percent; suggesting a technical potential of 400 to 2500 megawatts. Only a portion of this potential is likely to be available because of navigational, aesthetic or ecological concerns, and the need to maintain clearance between wave power units. Wave power in the Northwest is winter peaking with a high seasonal variation of a factor of 20. Wave energy technology is in its infancy. A diversity of conceptual designs have been proposed and several prototypes and demonstration projects constructed. Though it is unlikely that a commercially viable technology will become widespread during the period of this plan, the recently proposed West Coast demonstration projects suggest that the process of winnowing and refining technologies may accelerate.

Wind

Winds blow everywhere and a few very windy days annually may earn a site a windy reputation, but only areas with sustained strong winds averaging roughly 15 mph, or more are suitable for electric power generation. A good wind resource area will have smooth topography and low vegetation to minimize turbulence, sufficient developable area to achieve economies of scale, daily and seasonal wind characteristics coincident to electrical loads, nearby transmission, complementary land use and absence of sensitive species and habitat. Because of the low capacity factors typical of wind generation, transmission of unshaped wind energy is expensive. Interconnection distance and distance to shaping resources are very important.

Because of complex topography and land use limitations, only localized areas of the Northwest are potentially suitable for windpower development. However, excellent sites are found within the region. Wind resource areas in the Northwest include coastal sites with strong but irregular storm driven winter winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges receive concentrated prevailing westerly winds, wintertime northerly winds and winds generated by east-west pressure differentials. The Stateline area east of the Columbia River Gorge, Kittitas County in Washington and the Blackfoot area of north central Montana are of this type. A third type of regional wind resource area is found on the north-south ridges of the Basin and Range geologic region of southeastern Oregon and southern Idaho.

Intensive prospecting and monitoring are required to confirm the potential of a wind resource area. Though much wind resource information is proprietary, the results of early resource assessment efforts of the Bonneville Power Administration, the U.S. Department of Energy and the State of Montana, recently compiled resource maps based on computer modeling plus a the locations of existing and announced wind projects give a sense of the location and characteristics of prime Northwest wind resource areas. Educated guesses by members of the Council's Generating Resource Advisory Committee are that several thousand megawatts of developable potential occur within feasible interconnection distance of existing transmission. The magnitude of this estimate is supported by the 3600 megawatts aggregate capacity of undeveloped wind projects announced over the past several years. For the base case analyses of this plan we assume 5000 megawatts of developable potential west of the Continental Divide.

Central-station wind plant: The reference plant is a 100-megawatt wind plant located in a prime wind resource area within 10 to 20 miles of an existing substation. The plant would include 50 to 100 utility-scale wind machines. Sites west of the Rocky Mountains classified into two classes (blocks) of 2500 megawatts each. The first block is assumed to yield a capacity factor of 30 percent and incur shaping costs of $4.55/MWh. The benchmark cost for shaped power delivered to a customer on the main grid is $35/MWh in 2010. The second block is of lesser quality, yielding a capacity factor of 28 percent and shaping costs of $9.75/MWh. The benchmark cost for shaped power delivered to a customer on the main grid is $43/MWh in 2010. Sites east of the Rocky Mountains are assumed to yield a capacity factor of 36 percent and a shaping cost of $9.75/MWh. The benchmark cost of shaped power, delivered locally, is $33/MWh. These latter sites are electrically isolated from the regional load centers and would require construction of long-distance transmission to access outside markets.

Table 5-4: Generating resource planning assumptions

	Unit Size (MW)	Capital ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh) (base/CHP)	Technology Improvement (cost/heat rate %/yr)	Operat-ing Availab ility (%)	Shaping ($/ MWh)	Fixed Trans-mission ($/kW/yr)	Trans-mission Loss (%)	Dvl/Cnst Schedule (months)	Dvl/ Cnst Cash flow (%)
Coal steam-electric	400	$1243	$40	$1.75	9550	0.1%/-0.3%	84%	--	$15	1.9%	36/42	3%/97%
Coal gasification combined-cycle (no CO2 separation)	425	$1400	$45	$1.50	7915	-0.5%/-0.5% (post-2011)	83%	--	$15	1.9%	36/48	2%/98%
Coal gasification combined-cycle (CO2 separation)	401	$1800	$53	$1.60	9290	-0.5%/-0.5% (post-2011)	83%	--	$15	1.9%	36/48	2%/98%
Geothermal flash steam	50	$1830	$96	Inc. in fixed	9300	-1.1%	92%	--	$15	1.9%	36/24	16%/84 %
Natural gas-fired gas turbine generator	94	$600	$8	$8.00	9955	-0.5%/-0.5%	94%	--	$15	1.9%	12/12	3%/97%
Natural gas-fired combined-cycle	610	$525	$8	$2.80	7030 (base) 9500 (peak)	-0.5%/-0.5%	90%	--	$15	1.9%	24/24	4%/96%
Oil sands cogeneration	2000	$1071	Inc. in Variable	$2.80	5800	-0.5%/-0.5%	95%	--	$9	7.7%	48/36	5%/95%
Advanced nuclear power plants	1100	$1450	$40	$1.00	9600	0%/0%	88%	--	$15	1.9%	36/60	8%/92%
Wood residue steam-electric	25	$2000	$80	$9.00	14,500/4500	0%/0%	90%	--	$15	1.9%	24/24	5%/95%
Landfill gas energy recovery	1	$1360	$125	$1.00	11,100	0%/0%	80%	--	$15	1.9%	12/12	5%/95%
Animal manure energy recovery	0.5	$3100	$67	Inc. in fixed	11,100	0%/0%	90%	--	$15	1.9%	24/12	5%/95%
Chemical recovery boiler cogeneration	25	$680	Inc. in variable	$14.00	4500 (CHP)	0%/0%	90%	--	$15	1.9%	24/12	5%/95%
Photovoltaics	0.002	$7000	$32	$0.00	--	-8%		$4	--	--	<12	100%

	Unit Size (MW)	Capital ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh) (base/CHP)	Technology Improvement (cost/heat rate %/yr)	Operat-ing Availab ility (%)	Shaping ($/ MWh)	Fixed Trans-mission ($/kW/yr)	Trans-mission Loss (%)	Dvl/Cnst Schedule (months)	Dvl/ Cnst Cash flow (%)
Wind power[12]	100	$1010	$20	$1.00	--	-2%	B1 30% B2 28% B3 36%	$4.55 $9.75 $9.75	$20	1.9%	24/12	8%/92%

[12] Wind power is divided into three blocks. Block 1 (B1) represents better quality Washington, Oregon, Idaho and western Montana resources. Block 2 (B2) represents lesser quality, yet promising Washington, Oregon, Idaho and western Montana resources. Block 3 (B3) represents better quality resources of central and eastern Montana.