Cogeneration and Distributed Generation[1]

This appendix describes cogeneration and distributed generating resources. Also provided is an assessment of the prospects for the further development of cogeneration and distributed generation in the Northwest. Cogeneration and distributed generation are distinguished from central station electric power generation by the considerations governing plant location and design. Central station plants are sited and designed to minimize bulk electric power production costs. Among the key considerations are fuel supply, transmission, reject heat disposal and other site infrastructure requirements. In contrast, cogeneration and distributed generation are sited with respect to some aspect of load. These aspects may include the presence of thermal loads that may be served by cogeneration, loads that might be displaced to relieve the need for transmission or distribution system reinforcement, remote loads more economically served by small-scale generation than by distribution system expansion and loads needing additional electrical reliability or power quality.

This introductory section continues with general descriptions of distributed generation and cogeneration. The section that follows describes the principal technologies suitable for either cogeneration or power-only distributed generation. These include small steam-electric plants, gas turbines, reciprocating engines, fuel cells, microturbines and Stirling engines. This section concludes with a description of the cost and performance of several proposed Northwest cogeneration projects. The next section contains an assessment of the prospects for further development of cogeneration and distributed generation in the Northwest. It concludes with a discussion of the barriers to the development of cogeneration. The final section describes solar photovoltaic technology and small wind turbine systems.

All cost values are expressed in year 2000 dollars unless otherwise indicated. Thermal efficiency and heat rate values are on a higher heat value basis.

Distributed Generation

Distributed generation is the production of power at or near electrical loads. This may be necessary or desirable for the following reasons:

- 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 of heating or cooling loads.

[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.

- Power generation using an on-site byproduct suitable as fuel.
- Local voltage support during periods of high demand.
- Reliability upgrade for systems 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 technologies 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. Technologies in the early commercial stage include microturbines and fuel cells. Stirling engines, though not yet commercial may eventually play a role in distributed generation and cogeneration.

The selection of a generating technology for distributed generation is very dependent upon the application. Applications with low load factors such as standby power favor technologies having low initial cost, such as reciprocating engines. Higher efficiency and low emissions are more important with applications having higher expected load factors such as premium power and cogeneration applications. Reject heat characteristics are important for cogeneration applications.

Because of the small size of many distributed generation applications, the unit cost of equipment tends to be higher and the efficiency lower than for the large-scale equipment used for central-station generation. Likewise, fuel costs tend to be higher because of smaller scale. For these reasons, distributed generation rarely can compete with central station generation on the basis of busbar energy cost. It is the additional value imparted by the factors listed above that can make distributed generation attractive.

Cogeneration[2]

Cogeneration is the joint production of electricity and useful thermal or mechanical energy for industrial process, space conditioning or hot water loads. Because cogeneration opportunities tend to be located at electrical loads, cogeneration plants are largely a subset of distributed generation. Productive use of the rejected heat from electricity generation prime movers and,

[2] The discussion of cogeneration of this appendix focuses on industrial or commercial cogeneration (sometimes called "high -efficiency" cogeneration) where the primary factor governing the siting, design and operation of the power plant is the cogeneration load. Some central station power plants, particularly gas turbine combined-cycle plants supply steam to nearly thermal loads. While these are valid cogeneration applications and the overall thermal efficiency of the process is improved, the cogeneration load is subordinate to the power production mission of the plant and the plant characteristics are not greatly different than the power only plants described in Appendix I. The heat rate of large gas turbine combined-cycle plants with an incidental process steam load may run 4 to 7 percent lower than power-only plants.

often, higher quality initial steam conditions improves the overall energy efficiency of a cogeneration process compared to separate production of the energy products. Production costs and environmental impacts are often lower than with than separate production. Cogeneration includes 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 currently used include gas turbine generators, combined-cycle power plants, steam-electric plants and reciprocating engine generator sets. The greatest near-term 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.

TECHNOLOGIES FOR COGENERATION AND DISTRIBUTED GENERATION

Gas-turbine generators, reciprocating engines and steam-electric plants are commercially mature technologies that have been used for many years for large and mid-scale cogeneration and power-only applications. Fuel cells, microturbines and Stirling engines are emerging power generation technologies that appear likely to expand the feasibility of cogeneration and distributed generation to smaller-scale applications. These technologies may also reduce the environmental impact of distributed power generation. Solar photovoltaic technology differs from the preceding technologies by not typically producing reject heat[3], and thus is not suitable for cogeneration. However, solar photovoltaics are suitable for many distributed generation applications.

Small steam-electric plants

Steam turbine generators have been in use for about a century for central-station power generation and cogeneration. A steam electric generating plant consists of fuel storage and processing facilities, steam generating equipment (furnace, boiler and air emission controls), a steam turbine generator, a steam condenser and boiler feedwater system and a condenser cooling system. Steam for cogeneration can be extracted at various pressures depending upon the needs of the thermal load. High-pressure steam may be taken directly from the boiler and admitted to the steam turbine after process use. Lower pressure steam can be extracted from one or more stages of the steam turbine. Lower-pressure steam can also be obtained by use of a backpressure turbine in which the turbine is designed to exhaust at the desired steam temperature and pressure. Complex applications such as pulp and paper facilities may extract steam for process use at several pressures. Though steam turbines are manufactured in sizes ranging from kilowatt-scale mechanical drive units to 1300-megawatt units used for nuclear stations, turbines for cogeneration plants typically range in size from about one to one hundred megawatts. Large industrial cogeneration facilities are often comprised of multiple boilers and several smaller steam turbine generators rather than a single large machine, especially if the facility has been developed over time.

[3] There are exceptions. Some concentrating solar photovoltaic designs require cooling and potentially could serve cogeneration loads.

Steam-electric technology is well suited for large industrial cogeneration applications because of a low power-to-steam ratio[4] and because boilers can be designed to use byproduct fuels of industrial operations such as wood residues, spent pulping liquor and petroleum coke. Municipal solid waste, natural gas, fuel oil and coal can also be used. Furnaces, boilers and emission control systems can be designed to use these fuels singly, alternately or simultaneously. Coal, fuel oil and natural gas are frequently used as supplemental fuels if the residue fuel supply is insufficient to produce the needed quantity of process steam.

Steam-electric cogeneration facilities are characterized by high reliability and long life. Industrial steam-electric cogeneration plants can routinely achieve plant availabilities of 95 percent or greater and 50-year old facilities are not uncommon. The efficiency of steam-electric technology in power-only applications is low to moderate, ranging from 10 to 15 percent for small simple plants (stand-alone bio-residue plants, for example) to 37 to 38 percent for large central-station plants using sophisticated steam cycles. Cogeneration greatly improves the efficiency of these plants. The overall efficiency of plants with continuous thermal loads can approach 75 to 80 percent. Because of thermal stress considerations, steam-electric plants typically require extended startup times and have limited cycling ability. Because of these physical limitations, typically high capital costs and low fuel costs, steam-electric plants are best suited for baseload applications.

The overall unit (per kilowatt) capital cost (boiler and steam turbine generator) of steam-electric plants are high compared to other generating technologies because of the complexity of the plant and associated fuel handling, emission control and heat rejection systems; severe operating conditions imposed by certain fuels and the custom or semi-custom nature of most plants. Opportunities exist for adding steam turbine generators to existing boiler-process steam systems, or for upgrading elements of existing steam-electric cogeneration systems. These modifications can often be accomplished at much lower cost than the cost of a complete new facility. The cost and performance characteristics of several small steam-electric plants are summarized in Table J-1. The first three consist of a backpressure steam turbine generator added to an existing boiler system supplying steam to an industrial process. Two capital costs shown for these examples. The first is the incremental costs for the power generating equipment (steam turbine generator). The second is the incremental cost of power generation equipment plus an allowance of 50% of new balance-of-plant costs for boiler, fuel handling and emission control systems upgrades to accommodate addition of electrical generation. (Assuming the incremental cost of the steam turbine generator represents about 20 percent of the overall cost of the steam and power plant.) The first value is representative of an ideal, but probably rare application, where needed balance-of-plant upgrades are minimal. The second figure, though highly variable, represents the more common situation where significant balance-of-plant upgrades are required. The fourth plant shown in the table is a complete, stand-alone steam-electric generating plant. This type of a plant might be developed where a supply of low-value fuel (e.g., forest thinnings) is located in an area remote from a suitable cogeneration load.

The *electrical heat rate*, shown in the fourth row of the table is based on the overall fuel consumption of the plant. The electrical heat rate of a small steam-electric cogeneration plant is high compared to other generation technologies because of the large amount of energy rejected by the steam turbine condenser. Productive use of this otherwise wasted energy provides the

[4] The ratio of electricity to process steam obtainable from a unit of fuel input energy.

high thermal-to-electrical output of these plants when designed for cogeneration. The *net heat rate*, shown in the fifth row is based on the overall fuel consumption of the cogeneration plant less the amount of energy that would be required to produce the thermal load of the plant if no cogeneration system was installed[5]. The net heat rate is the incremental electric generating efficiency of a cogeneration plant and is the heat rate normally used to calculate the cost of fuel for electricity generation (hence the term *fuel charged to power* for the overall fuel consumption of the plant less the thermal load). As evidenced by the relatively low net heat rates of the cogeneration examples of the table, the net electrical generating efficiency of a steam-electric in which most of the otherwise rejected energy is used for cogeneration is very high - on the order of 75 to 80 percent.

Table J-1: Cost and performance of representative small steam-electric plants (Year 2000 dollars, 2003 technology base year)

	0.5 MW chemical plant back-pressure cogeneration	**3MW pulp and paper back-pressure cogeneration**	**15 MW pulp and paper back-pressure cogeneration**	**25 MW forest residue energy recovery**
Capital cost ($/kW)	$870[6]/3050[7]	$360[6]/1260	$330[6]/1160	$1800 - $2000
Fixed O&M ($/kW/yr)	Included in variable O&M	Included in variable O&M	Included in variable O&M	$80
Variable O&M ($/MWh)	$3.80[6]	$3.80[6]	$3.80[6]	$9
Electrical Heat Rate (Btu/kWh)	53,300	49,500	37,900	14,500
Net Heat Rate (Btu/kWh)	4520	4570	4390	4500
Electrical heat rate reduction 2003-25 (%/yr)[8]	0.0%	0.0%	0.0%	0.0%
Cost reduction 2003-25 (%/yr)	-0.4%	-0.2%	0.0%	0.0%
Benchmark Electricity Cost ($/MWh)[9]	$35/60	$30/40	$29/39	$65[10]/55[11]

[5] Assuming 80% boiler efficiency.
[6] Incremental costs of steam turbine generation only (boiler and other balance of plant equipment assumed to be present). From NREL, Gas-fired Distributed Energy Resource Technology Characterizations. November 2003.
[7] Incremental cost of steam-turbine generator plus balance-of-plant upgrades (arbitrary 50% of estimated new balance-of-plant cost).
[8] Turbine-generator improvements only.
[9] Benchmark levelized electric cost, constant year 2000 dollars. Based on mixed financing (20% publicly-owned utility, 40% investor-owned utility, 40% independent, see Appendix I), 2010 service, 30-year service life, 90% capacity factor. Values for backpressure turbine case are based on industrial natural gas fuel, values for forest residue case are based on the medium case forecast of the cost of forest residue fuel. Backpressure cogeneration cases include $2/kW/yr capacity service charge and the mean value of the CO2 penalty from the portfolio analysis of this plan. The forest residue plant is assumed to be subject to transmission losses of 1.9% and transmission charges of $15/kW/yr.
[10] Power-only.
[11] Cogeneration with full heat recovery (optimal).

The National Renewable Engineering Laboratory (NREL) has forecast the effect of future technological advances on installation cost, operating cost, heat rate and other characteristics of steam turbine generators for the period 2003 through 2030. Included in Table J-1 are the average reductions in heat rate and cost over this period derived from the more detailed NREL forecasts[12]. Though steam turbines are a mature technology, some reduction in the cost of smaller units is expected through gradual application of large-scale steam turbine technology improvements to the smaller-scale turbine-generators.

Appearing in the last row of Table J-1 are benchmark electricity costs. The electricity costs for the three backpressure turbine cases assume that the incremental fuel requirements are met by industrial natural gas. In practice, lower-cost bioresidues would often provide the incremental fuel. The fuel supply for the new 25 MW plant is forest residue at the medium price forecast of the power plan. For the three backpressure turbine cases, the electricity cost above the slash is based on the incremental capital cost of the power generation equipment only. This would represent an optimal situation. Values below the slash include the additional costs of balance-of-plant upgrades, which though arbitrary, are likely more representative of actual projects. For the 25 MW forest residue plant, the electricity price value above the slash represents a power-only configuration. The value below the slash is for a cogeneration application with full heat recovery.

The forecast levelized lifecycle electricity production costs of the steam turbine generation systems of Table J-1 are compared to levelized forecast wholesale and retail power prices in Figure J-1. The three systems consisting of incremental additions of power generation capacity to existing process steam systems are likely to displace host facility loads and thereby compete with retail power prices. Except for the 500 kW system, all appear to have strong potential to be cost-effective, even assuming substantial balance-of-plant improvements are required. Even the 500kW system would be cost-effective in those cases where relatively minor balance-of-plant upgrades would be required, or where low-cost residue fuels could be used in lieu of the natural gas. In practice, however, many of these opportunities appear not to be developed. This may attributable to the financing ability and payback requirements of the host industry. Manufacturing industries, where most of these opportunities occur, generally require much higher returns and shorter paybacks than the utility industry.

The power-only forest residue plant would likely compete on the wholesale power market. The substantial difference between the cost of power from this plant and forecast wholesale power prices illustrates the challenging economics faced by this type of project. As illustrated in the figure, project economics could be considerably more favorable if a suitable cogeneration load is available. Not only are fuel costs reduced by the value of the process steam, but the load displacement potential shifts the competition to the higher price retail market.

[12] NREL (2003) includes forecasts of the effects of technological development on several technology characteristics for several time intervals, 2003 through 2030. The technological development rates appearing in Table J-ST1 and the other equivalent tables of this appendix are the average annual forecast rates of improvement for installation cost and heat rate for the period 2003-30 (2005-30 for fuel cells and microturbines). This simplified representation captures the key factors influencing the future electricity production costs of these technologies and is consistent with the treatment of generating technology development used elsewhere in this plan. When calculating future electricity production costs, the forecast effect of technology development on installation cost is applied both to capital and to fixed non-fuel operating costs (all non-fuel operating and maintenance costs in cases where all operating costs are reported as variable).

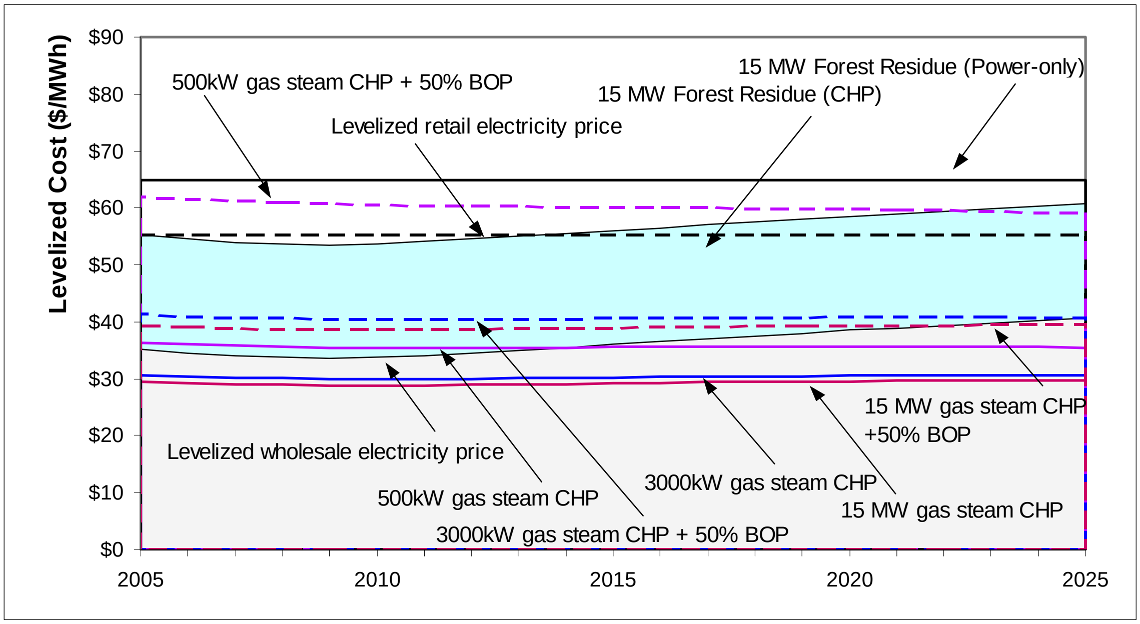

Figure J-1: Forecast cost of electricity from small steam-electric plants

Air emissions associated with steam-electric plants are a function of the fuel and emission controls. Projects involving substitution of a backpressure turbine for an existing steam throttle valve would result, at worst, in no incremental emissions attributable to power generation. Though projects involving boiler upgrades may require additional fuel input to produce higher quality steam, the new boiler often is more efficient and has improved emission controls compared to its predecessor.

In the Northwest, the incremental boiler fuel is likely to be wood residue, natural gas or coal. The major pollutant of concern for wood-fired boilers is particulate matter. Nitrogen oxides (NOx) are the principal emissions of concern from natural gas fired boilers. Particulate matter, sulfur oxides and nitrogen oxides are the pollutants of concern with boilers fired with coal. Representative uncontrolled and controlled rates of these emissions for boilers fuelled by natural gas, coal and wood residues are shown in Table J-2.

NOx emission controls for boilers include low-NOx burners (low excess air firing), flue gas recirculation, low nitrogen fuels, water or steam injection and selective and non-selective catalytic reduction. These methods, used singly, or in combination can achieve up to 90 percent reduction in NOx levels. SOx emissions are reduced by use of low-sulfur fuels and flue gas desulphurization (FGD). SOx emission reduction of 95 percent, or greater can be achieved by FGD systems. Fabric filters (baghouses) and electrostatic precipitators are used to control particulate emissions. Removal efficiencies exceeding 99 percent are achievable. Combustion controls and oxidation catalysts are used to control hydrocarbon and CO emissions. Because of their expense, FGD, catalytic controls and other complex control systems can only be justified on large plants and plants using potentially hazardous fuels such as unsorted municipal solid waste. The combustion of all hydrocarbon fuels (including biomass) produce carbon dioxide in proportion to the carbon-to-hydrogen ratio of the fuel. The net carbon dioxide production from biomass fuels obtained from sustained harvest will be zero over time.

Table J-2: Representative air emissions from small steam-electric plants[13] [14]

		Natural Gas	Coal[15]	Wood Residues[16]
Particulates (PM-10) (t/GWh)	Uncontrolled Controlled	0.05	5.6 0.06[17]	4.35 0.29[18]
SOx (t/GWh)	Uncontrolled Controlled	Negligible	7.4 0.7[19]	0.18
NOx (t/GWh)	Uncontrolled Controlled	1.35 1.00[20]	3.7 1.9[21]	1.6
CO (t/GWh)	Uncontrolled Controlled	0.60	2.1	4.35
CO_2 (t/GWh)	Uncontrolled	850	2030	None on net assuming sustainable biomass harvest

Gas turbine generators

Gas turbine generators suitable for distributed generation and cogeneration range from about 700 kilowatts to about 50 megawatts capacity. Machines in the lower end of the size range are based on mechanical drive units developed for oil and gas industry applications. Machines of the mid-to-upper end of this range are aeroderivative turbines - aircraft gas turbine engines adapted to stationary use. Small gas turbine generators are generally supplied as skid-mounted units consisting of a gas turbine; electric generator; air intake, filter, and silencer; exhaust stack; starter, controls, often enclosed by a sound-attenuation structure. Though a mature technology, extensively used in transportation, remote power supply and mechanical drive applications, gas turbine improvements are expected to continue, driven by demands of the aerospace industry.

Gas turbine generators can be adapted to a variety of gas or liquid fuels including distillate fuel oil, propane, natural gas, biogases and synthetic gases. Reliability is excellent, especially when used for continuous duty operation, and availabilities of 90 to 98 percent[22] are achievable. Routine maintenance is a function of operating hours, startups and the extent of overload operation. Gas turbines offer quick black start capability and are suitable for load following, though electrical efficiency declines rapidly at less than 70 to 80 percent of full load. The full-load electrical efficiency of small gas turbine-generators ranges widely, from 22 to 37 percent[23],

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[13] Emissions based on emission factors USEPA AP-42.
[14] Assumed heat rate 14,500 Btu/kWh.
[15] Subbituminous, 8600 Btu/lb, 0.5% sulfur.
[16] Bark and wet wood.
[17] Electrostatic precipitator with 99% removal efficiency.
[18] Electrostatic precipitator.
[19] Wet limestone scrubber with 90% removal efficiency.
[20] Low-NOx burners.
[21] Low-NOx burners with overfire air; 50% removal efficiency.
[22] U.S. Department of Energy. Combined Heat and Power : A Federal Manager's Resource Guide. March 2000. Table 2-4.
[23] Higher heating value basis.

increasing with machine size. Gas turbine power output and efficiency decline with increasing ambient air temperature. Inlet air chillers are available to offset losses at high ambient temperatures. Power output (but not efficiency) declines with elevation.

Because of their somewhat low efficiency compared to other power-only generating alternatives, power-only gas turbine generators are best suited for low load factor applications such as peaking generation, grid support, standby service and mobile grid-support units. However, the somewhat low efficiency of a gas turbine results in high turbine exhaust volume and temperature. Capture of the energy contained in this exhaust using unfired or supplementary-fired heat recovery steam generators permits production of high quality steam for process or steam turbine generator use (combined-cycle generation). Gas turbine exhaust may also be used for direct heating applications. Also because of the somewhat low efficiency of the gas turbine, the thermal output to power output ratio is high. The overall efficiency of cogeneration units can exceed 70 percent and these units are commonly found in continuous duty operation.

Cost and performance characteristics of small gas turbine generators fuelled by natural gas are summarized in Table J-3. Cost values appearing above the slash are for power-only applications; values below the slash are for cogeneration applications. The estimates include the cost and efficiency penalty of fuel compressors. These are required in locations serviced at typical distribution system supply pressures. Power-only costs do not include post-combustion emission controls, and are representative of low-load factor applications. Cogeneration examples include the cost of selective catalytic reduction for nitrogen oxides and an oxidation catalyst for control of CO and hydrocarbons; typically required for high load factor applications.

Table J-3: Cost and performance of small gas turbine generators and cogeneration plants[24, 25]
(2003 technology base year)

	1MW	5 MW	10 MW	25 MW	40 MW
Capital cost ($/kW)[26]	$1330/2090	$740/1130	$680/1040	$620/910	$560/810
O&M ($/MWh)[27]	$9.10/10.50	$5.60/6.50	$5.20/6.10	$4.60/5.60	$4.00/4.80
Electrical Heat Rate (Btu/kWh)	15,580	12,590	11,770	9950	9220
Net Heat Rate (Btu/kWh)[28]	7210	6340	5950	5450	5240

[24] From National Renewable Energy Laboratory, Gas-fired Distributed Energy Resource Technology Characterizations, November 2003. Costs deescalated to year 2000 dollars.
[25] Natural gas fuel.
[26] Power-only configuration above the slash; cogeneration configuration below the slash. Cogeneration applications are assumed to include SCR and catalytic oxidation. The additional cost of SCR and oxidation catalyst is assumed to be 45 percent of basic equipment cost. Turbine-generator equipment cost from (GT) Table 3 of National Renewable Energy Laboratory, Gas-fired Distributed Energy Resource Technology Characterizations, November 2003.
[27] Power-only configuration above the slash; cogeneration configuration below the slash.. O&M for cogeneration increased in proportion to SCR and oxidation catalyst portion of capital cost.
[28] Net heat rate is the total fuel energy input less the energy value of the equivalent fuel required to serve the cogeneration load (assuming 80% boiler efficiency) divided by the energy value of the electricity produced. The values shown assume full use of the available reject heat for cogeneration.

Electrical heat rate reduction 2003-25 (%/yr)	0.0	-0.9%/yr	-0.8%/yr	-0.6%/yr	-0.4%/yr
Cost reduction 2003-25 (%/yr)	0.0	-0.9%/yr	-0.7%/yr	-0.6%/yr	-0.3%/yr
Benchmark Electricity Cost ($/MWh) [29]	$76	$48	$45	$41/44	$39/42

Though stationary gas turbines have been in commercial service for a half century, further cost reduction and continued improvement in efficiency, specific power and emission characteristics are anticipated. Higher efficiency will be achieved through increased firing temperature, higher pressure ratios and reduction in bypass losses. These improvements will be accomplished by improved blade aerodynamics and sealing, internal blade cooling, thermal barrier coatings and ceramic hot section materials. The increased production of nitrogen oxides (NOx) potentially resulting from higher firing temperatures will be offset by catalytic (flameless) combustion and improved post-combustion controls such as the ammonia-free SCONOx™ NOx and CO catalytic conversion/absorption system. Technological and cost improvements to the smaller gas turbines described in this section are likely to result from technology transfer from aerospace and large industrial turbines and possibly from microturbine development. Included in Table J-3 are forecast average annual reductions in electrical heat rate and installation cost resulting from these improvements[30]. Concurrent reductions in emissions are also expected. No improvement is forecast for the one-megawatt example because of the uncertain future for gas turbines of this size because of the expected dominance of reciprocating engines for this size class.

Benchmark electricity production costs are shown in the last row of Table J-3. The three smaller units would likely operate to displace the electrical load of the host facility. Accordingly, the values for these units and the values above the slash for the two larger units assume load displacement operation. These values omit transmission costs and include a capacity service charge. The two larger units could produce amounts of power in excess of host facility loads, so might compete with wholesale electricity prices. Estimated production costs for wholesale grid sales are shown below the sash for these cases. These costs omit the capacity service cost but include transmission costs.

Forecast levelized lifecycle electricity production costs of the gas turbine cogeneration systems of Table J-3 are compared to levelized forecast wholesale and retail power prices in Figure J-2. The solid lines represent electricity costs for load displacement operation assuming a full cogeneration load. All cases, except for the one-megawatt unit are economically competitive with forecast retail electricity prices. It appears unlikely that very small installations, as represented by the one-megawatt unit could be generally cost-effective at any time during the planning period except for exceptional circumstances such as very high locational benefits. Though the larger units appear to be strongly competitive under the assumptions used here,

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[29] Benchmark levelized electric cost, constant year 2000 dollars for applications with full cogeneration loads. Based on mixed financing (20% publicly-owned utility, 40% investor-owned utility, 40% independent, see Appendix I), 2010 service, 20-year service, 20-year maximum amortization, industrial natural gas supply, 90% capacity factor and the mean value of the CO2 penalty from the portfolio analysis of this plan. Load-displacement values (values for smaller cases and above-the-slash values for the two largest cases) include a $2/kW/yr capacity service charge. Grid sales values (below-the-slash) for the two largest cases include $15/kW/yr point-to-point transmission costs and losses of 1.9%, but exclude a capacity service cost.

[30] See footnote 12.

factors such as short payback requirements or less-than full cogeneration load could increase the cost of these installations in practice.

The electrical output of the larger units could easily exceed the electrical load of a host facility, requiring wholesale sales of surplus power to maintain capacity factor. The dashed lines for the two larger units include transmission costs and are representative of the cost of power for sale to the grid. Wholesale grid sales appear generally not to be competitive until late in the planning period unless high locational value or other special circumstances improved the cost-effectiveness of a project.

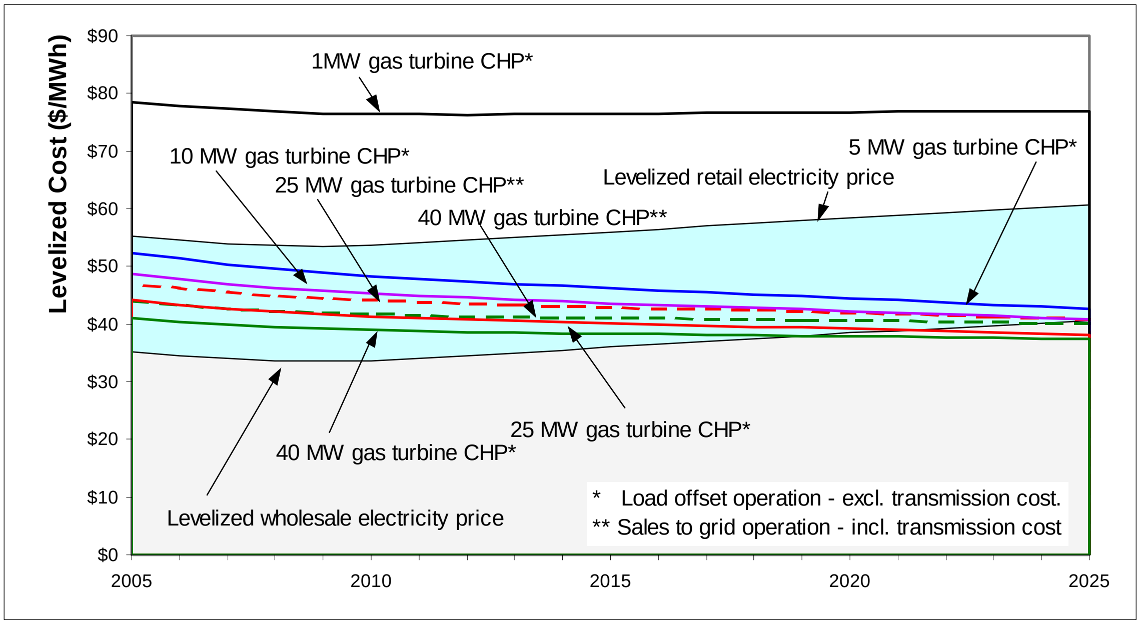

Figure J-2: Forecast levelized cost of electricity from gas turbine cogeneration plants

Nitrogen oxides are the primary pollutant of concern for gas turbines. Carbon monoxide (CO) and to a lesser extent, volatile organic compounds (VOC) can also be of concern. Oxides of sulfur and particulates can be of concern for units burning fuel oil, though extended operation of units on fuel oil operation is rare because of fuel cost. Nitrogen oxide emissions can be controlled at the source by reducing peak combustion temperatures through injection of water or steam or by use of lean premixed “low-NOx” combustors. Post-combustion catalytic reduction controls (selective catalytic reduction for nitrogen oxides and oxidation catalysts for CO and hydrocarbon emissions[31]) can further reduce emissions by 65 to 90 percent for NOX, 90 percent for CO and 85 - 90% for hydrocarbons. Post-combustion controls are often required for cogeneration and other high load factor applications. Because of the expense, post-combustion controls are uncommon on low load factor applications; however the allowable annual operating hours of these installations may be restricted to control overall emissions. Fuel sulfur content and operating hour restrictions are often used to control the formation of sulfur oxides for units operating on fuel oil. Typical air emission rates for gas turbine generators operating on natural

[31] The oxidation catalyst converts oxidizes carbon monoxide and hydrocarbons to carbon dioxide and water.

gas fuel and equipped with post combustion control systems for NOx and CO are shown in Table J-4.

Table J-4: Representative air emissions from gas turbine cogeneration plants[32]

	1MW	5 MW	10 MW	25 MW	40 MW
NOx (t/GWh)[33]	0.18	0.08	0.08	0.07	0.06
CO (t/GWh)[34]	0.04	0.03	0.03	0.02	0.02
VOC (t/GWh)[35]	<0.01	<0.01	<0.01	<0.01	<0.01
CO_2 (t/GWh)	910	740	690	580	540

Reciprocating engines

Reciprocating engine-generator sets are packaged spark- or compression-ignition internal combustion reciprocating engines driving an electric generator. Engines for stationary applications are derived from truck, locomotive or marine engines. Though a commercially mature technology, improvements in efficiency and environmental performance have continued and even accelerated in recent years because of demand for more efficient and cleaner engines.

Reciprocating engines can be adapted to a variety of gas or liquid fuels including gasoline, diesel oil, propane, natural gas and biogases. Reciprocating engines offer quick black start capability, high reliability, low initial cost, easy maintenance, high part-load efficiency, good load-following capability and low water consumption. Hot water or low-pressure steam cogeneration loads can be served by heat recovery from the engine exhaust, cooling water jacket, lube oil cooler and air inlet chillers. Natural gas fuelled engines are used for industrial and commercial cogeneration and peak load service where natural gas service is available. Reciprocating engines can operate on low natural gas pressure, eliminating the fuel gas compression needed for gas turbine generators operating from low-pressure supplies. Reciprocating engines can be modified to operate on landfill, wastewater treatment and other biogasses. Engines operating on fuel oil are used for emergency backup service and mobile grid-support units.

The principal internal combustion reciprocating engine technologies include spark ignition engines, compression-ignition engines and dual-fuel compression ignition engines. Spark-ignition (SI) engines use spark plugs to ignite the compressed fuel-air mixture. With suitable fuel handling systems, compression ratios and tuning, SI engines can be used with a variety of gas and volatile liquid fuels including natural gas, gasoline, propane and biogases. Natural gas SI engine-generators are available up to about 4 megawatts capacity. All except the smaller units are typically equipped with turbochargers and intercoolers. “Lean burn” designs use low fuel-air ratios and enhanced ignition to reduce NOx production. Post-combustion controls including

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[32] Based on electrical heat rate. Net emissions may be less because of displacement of cogeneration thermal loads.
[33] Assumes use of selective catalytic reduction with 85% NOx removal effectiveness.
[34] Assumes use of catalytic oxidation with 90% CO removal effectiveness.
[35] VOC values based on USEPA AP-42 Volume 1, Chapter 3.1 Stationary Gas Turbines for Electricity Production. Assumes use of catalytic oxidation with 90% VOC removal effectiveness.

three-way catalysts, selective catalytic reduction and oxidation catalysts can further reduce NOx, CO and VOC emissions. Spark-ignition engines are generally derived from compression-ignition (CI) engine designs. Because the lower compression ratios of SI engines compared to the CI engines from which they are derived reduce efficiency and power output, the cost per kilowatt capacity tends to be higher. The efficiency of natural gas SI engine-generators operating in power-only applications ranges from 25 to 36 percent.

In compression-ignition (CI) engines, fuel is injected into the cylinder near the end of the compression stroke where it ignited by the high temperature of the compressed air. Light distillate fuel oils are the most common fuel, however large low-speed CI engines, available in sizes as large as 80 megawatts can also burn heavy fuel oils. CI engines are typically equipped with turbochargers and intercoolers. Uncontrolled CI engines produce much higher levels of NOx and higher levels of unburned hydrocarbons than SI engines. Uncontrolled CO production is somewhat lower than SI engines. Uncontrolled SOx production can be high with fuels of high sulfur content. A variety of combustion controls are employed to reduce NOx production. Post-combustion controls including selective catalytic reduction and oxidation catalysts can be used to reduce NOx, CO and VOC emissions. Low sulfur fuel oils and operating hour restrictions are used to control SOx production. Because of their higher compression ratios, the specific power and efficiency of CI engines are greater than for comparable SI engines. The efficiency of natural gas SI engine-generators operating in power only applications ranges from 29 to 41 percent.

Dual-fuel compression ignition engines combine the efficiency and high specific power of compression-ignition engines with the fuel flexibility and lower emissions characteristics of spark-ignition engines. In dual-fuel compression ignition engines, natural gas or other low energy density fuel is ignited at high compression pressure using a pilot injection of diesel fuel.

The output of reciprocating engines is sensitive to ambient air temperature and elevation. Optional inlet air chillers can offset derating due to warm ambient air conditions. Warranted engine ratings are based on three classes of intended duty: standby, prime and base-load. Availability to 96 percent and a 20-year service life is possible with well-maintained continuous duty units.

The installed capital cost of power-only grid-connected natural gas spark-ignition engines ranges from about $600/kW (larger units) to about $1000/kW (smaller units). Examples are shown in Table J-5 (values appearing above the slash). Cogeneration installations are more expensive (values below the slash in Table J-5) because of the additional equipment required for heat recovery and thermal system interconnection and because of the post-combustion air emission controls often required for the continuous duty operation. Actual cogeneration projects vary widely in cost because of site-specific conditions.

Non-fuel operating and maintenance costs are a function of engine size, speed, fuel, operation and emission control equipment and can also vary widely. Unfortunately, most reported information regarding non-fuel O&M costs fails to note if the costs associated with post-combustion emission control equipment are included, though these costs can be significant. Available information suggests that non-fuel O&M costs range from $5 to $10/MWh for natural gas units without post-combustion controls and $10 to $20/MWh for lean-burn natural gas fuelled units with post-combustion SCR and oxidation catalyst emission controls. Example costs are provided in Table J-5. Non-fuel O&M costs are often higher on units operating on fuels such as landfill gas where corrosive substances may be present.

Though reciprocating engines are a mature technology, continued cost reduction and improvements in efficiency, emissions characteristics, maintainability and longevity are expected. Competitive pressure, emissions regulations and research and development undertaken for the transportation market will continue to drive technology improvements for the stationary market. Likely areas of future improvement include increased compression ratios and speed, and improved controls, materials and exhaust gas treatment. Included in Table J-5 are forecast average annual reductions in electrical heat rate and installation cost[36]. Concurrent reductions in emissions are also expected.

Benchmark electricity production costs for cogeneration installations operating in load displacement mode are shown at the last line of Table J-5.

Table J-5: Cost and performance of grid-connected natural gas spark-ignition reciprocating engine-generators and cogeneration plants[37, 38] (Year 2003 technology base year)

	100kW rich burn	300kW lean burn	1000kW lean burn	3000kW lean burn	5000kW lean burn
Capital cost ($/kW)	$970/1280[39]	$750/1190[40]	$680/990	$670/980	$660/940
O&M ($/MWh)	$17	$12	$8.50	$8.10	$7.60
Electrical Heat Rate (Btu/kWh)	11,500	10,970	10,040	9700	9210
Net Heat Rate (Btu/kWh)	4500	4640	5420	5600	5050
Electrical heat rate reduction 2003-25 (%/yr)	-0.5%	-0.4%	-0.7%	-0.7%	-0.7%
Cost reduction 2003-25 (%/yr)	-1.2%	-1.0%	-0.8%	-0.8%	-0.7%
Benchmark Electricity Cost ($/MWh) [41]	$51	$47	$44	$45	$42

Forecast levelized lifecycle electricity production costs of gas turbine cogeneration systems of Table J-5 are compared to levelized forecast wholesale and retail power prices in Figure J-3. All cases represent electricity costs for load displacement operation with full cogeneration load. These omit transmission costs, but include a capacity service charge. Though no case is competitive with wholesale electricity prices, all cases are economically competitive with

[36] See footnote 12.
[37] From National Renewable Energy Laboratory, Gas-fired Distributed Energy Resource Technology Characterizations, November 2003. Costs deescalated to year 2000 dollars.
[38] Natural gas fuel.
[39] Including 3-way catalyst.
[40] Includes cost of exhaust gas emissions controls (SCR & oxidation catalyst).
[41] Benchmark levelized electric cost, constant year 2000 dollars. Based on mixed financing (20% publicly-owned utility, 40% investor-owned utility, 40% independent, see Appendix I), 2010 service year, 20-year service life, 20-year maximum amortization, industrial natural gas supply, 90% capacity factor, the mean value of the CO2 penalty from the portfolio analysis of this plan and a $2/kW/yr capacity service charge.

forecast retail prices and become increasingly so as the planning period progresses. Factors such as short payback requirements or less-than full cogeneration load could increase the cost of these installations in practice.

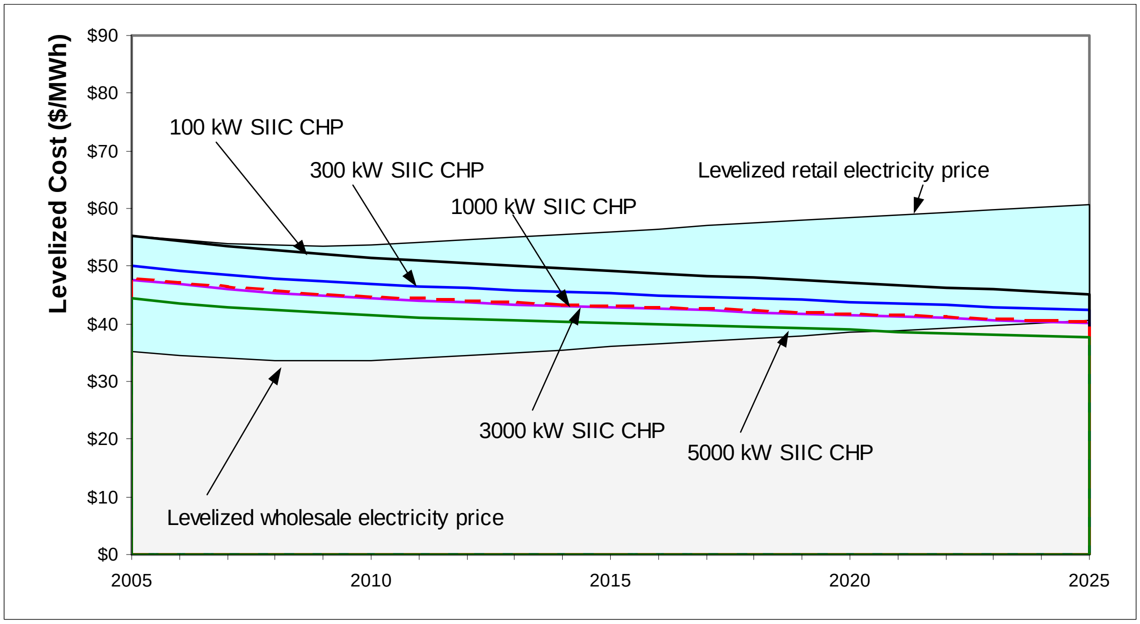

Figure J-3: Forecast levelized cost of electricity from natural gas spark-ignition reciprocating engine cogeneration systems

High levels of air emissions have been an important constraint to use of reciprocating engines for high duty factor applications such as cogeneration. The principal emissions of concern are nitrogen oxides, CO and hydrocarbons, and for oil-burning engines, oxides of sulfur. In recent years, effective combustion and post-combustion emission controls have become available to reduce emission rates. Three-way catalysts, similar to automotive catalytic converters are used on smaller "rich-burn" engines. These can reduce uncontrolled levels of NOx and CO by 90%, or more, and VOCs by 80%. Lean-burn (low oxygen/fuel ratio) engines have been introduced to reduce NOx formation, but even lean burn reciprocating engines without post-combustion air emission controls can have high NOx, CO and volatile hydrocarbon emissions. Selective catalytic reduction (SCR), used on lean burn units can reduce uncontrolled levels of NOx by an additional 80 to 95 percent, or more. Oxidation catalysts, also used on larger lean burn engines, promote conversion of CO to CO2 and combustion of unburned hydrocarbons. CO and non-methane hydrocarbon reduction can exceed 98% and methane levels can be reduced by 60 to 70 percent. While post combustion controls are often not provided on low duty factor engines such as those installed for standby or emergency purposes, they are becoming common on units, such as cogeneration installations, designed for high duty factor operation. Typical air emission rates for units operating on natural gas fuel and equipped with post combustion control systems are shown in Table J-6.

Table J-6: Representative air emissions from natural gas spark-ignition reciprocating engine-generators[42]

	100kW rich burn	300kW lean burn	1000kW lean burn	3000kW lean burn	5000kW lean burn
NOx (t/GWh)	0.23[43]	0.31[44]	0.16	0.11	0.08
CO (t/GWh)	0.09[45]	0.06[46]	0.06	0.08	0.07
VOC (t/GWh)	0.23[47]	0.03[48]	0.03	0.04	0.02
CO_2 (t/GWh)	670	640	590	570	540

Fuel cells

Fuel cells are electrochemical devices for converting the chemical energy of hydrogen (and in some designs, carbon monoxide) to electricity. A fuel cell, similar to a battery, consists of a cathode and an anode separated by an electrolyte. Unlike a battery, fuel is supplied continuously to the anode from an external fuel supply. Hydrogen, (in most designs in the presence of a catalyst) is dissociated into positively charged hydrogen ions and free electrons. The free electrons are prevented by the electrolyte from crossing directly to the cathode, but are conducted to the cathode by an external electrical circuit. This yields electric power. Depending upon the technology, either the positively charged hydrogen ions are conducted to the cathode through the electrolyte, or negative ions (OH^-, $CO3^=$ or $O^=$) are conducted from the cathode to the anode through the electrolyte. The hydrogen ions combine with the oxygen of the negative ions to form water. Individual fuel cells provide several volts of electrical potential and are typically connected in series in a fuel cell stack to achieve the desired output voltage.

Basic fuel cell technology was demonstrated in the 1830s and in the 1950s first developed for a practical application - space power supplies. Over the following decades, research and development efforts sought to develop practical economical fuel cells for bulk electric power generation. The first fuel cells for bulk electric power production were commercially introduced in the early 1990s. Despite substantial infusions of investment capital over the past decade, fuel cells have been very slow to penetrate the marketplace. Though the physical structure of most fuel cell technologies offers the potential for low-cost mass production, capital and operating costs have remained high because of the high cost of fuel cell fabrication and the limited fuel cell stack life. Fuel cells remain attractive for electric power generation because of quiet, efficient, low emission operation, modularity and cogeneration potential.

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[42] Based on electrical heat rate. Net emissions may be less because of displacement of cogeneration thermal loads.
[43] Assumes use of 3-way catalyst to reduce NOx by 99% (NREL, 2003).
[44] Assumes use of selective catalytic reduction to reduce NOx by 85%.
[45] Assumes use of 3-way catalyst to reduce CO by 99.5% (NREL, 2003).
[46] Assumes use of oxidation catalyst to reduce CO by 98% (NREL, 2003).
[47] Assumes use of 3-way catalyst to reduce VOC by 79% (NREL, 2003).
[48] Assumes use of oxidation catalyst to reduce VOC by 98% (NREL, 2003).

Fuel cell technologies are distinguished by electrolyte and operating temperature. Four types are suitable for stationary electricity generation: phosphoric acid fuel cells, proton exchange membrane fuel cells, molten carbonate fuel cells and solid oxide fuel cells.

Phosphoric acid fuel cells (PAFC) use liquid phosphoric acid as an electrolyte and porous carbon electrodes containing a platinum catalyst. The cell operates on pure hydrogen. Typically, hydrogen is supplied by an external fuel reformer, a device that converts carbonaceous fuels such as natural gas to hydrogen and carbon dioxide to hydrogen and water. Phosphoric acid fuel cells have a moderate power density and an electrical efficiency of about 36 percent. The moderate operating temperature of approximately 400^{o}F will support heat recovery for cogeneration in the form of hot water or low- to medium pressure steam from the fuel cell stack cooling system and as hot water from the cathode exhaust gas condenser. Recovery of byproduct heat can result in net thermal efficiencies exceeding 70 percent.

Packaged phosphoric acid fuel cell power plants were introduced to the market in the early 1990s by United Technologies (200kW ONSI PC-25 units). These, and subsequent phosphoric acid fuel cell units consist of a fuel reformer, the fuel cell stack, an inverter to convert the DC power output of the fuel cell stack to AC power and ancillary systems. High initial and operating costs, because of the platinum catalyst and the limited (approximately five-year) life of the fuel cell stack have constrained market penetration. However, about 250 PC-25 units are in operation in a variety of applications ranging from military power supplies to biogas energy recovery. Other fuel cell technologies having superior performance and cost characteristics are expected to displace phosphoric acid technology as they become commercial.

Proton Exchange Membrane (PEM) fuel cells (also known as polymer electrolyte membrane or polymer electrolyte fuel cells) employ a solid polymer electrolyte and porous carbon electrodes containing a platinum catalyst. Like phosphoric acid fuel cells, a PEM fuel cell operates on pure hydrogen and requires an external fuel reformer. The solid electrolyte provides a more robust design by reducing corrosion and leakage problems associated with liquid electrolytes. PEM fuel cells have very high power density, electrical efficiency of 30 to 35 percent and operate at low temperature, about 150 to 180^{o}F. The greatest near-term potential for PEM fuel cell technology appears to be transportation applications where high power density, flexible physical orientation, shock resistance and low operating temperature (facilitating quick startup) are desirable. Over the past decade, the automotive industry has made significant investments in PEM technology with the objective of commercializing auxiliary power units and eventually, propulsion power units. Advances in the transportation sector should facilitate the development of stationary electric power applications of PEM fuel cells.

Stationary power applications of PEM fuel cell technology include backup power service, package units for distributed residential and small commercial generation. Packaged 5kW PEM fuel cell units targeted at backup power service for telecommunications applications were introduced in 2003 by Plug Power. Packaged 5kW unit for continuous duty grid-connected cogeneration service were introduced in 2004. Though the low operating temperature limits heat recovery for cogeneration to low-grade hot water, this is satisfactory for space heating and hot water supplies (research is underway on membranes capable of operating at higher temperature). The fast start and ramping capability of PEM technology could make these fuel cells ultimately attractive for load following and peak shaving applications.

Molten Carbonate Fuel Cells (MCFC) use a liquid alkali carbonate salt electrolyte suspended in a porous ceramic matrix. Current designs employ a porous sintered nickel-chromium alloy anode and a porous nickel oxide cathode doped with lithium. Lithium carbonate and potassium carbonate electrolytes are the most commonly used. Operating temperatures of 1100 to 1200^{o}F maintain the carbonate salts in a molten condition. These temperatures eliminate the need for expensive noble metal catalysts required for lower-temperature fuel cells, provide higher efficiency and greater power density and can support cogeneration or combined-cycle applications requiring high-pressure steam (the original objective for molten carbonate fuel cell development was as the topping cycle of a combined-cycle power plant). Molten carbonate fuel cells are expected to have system electrical efficiencies in the 43 - 46 percent range, combined-cycle efficiencies approaching 60 percent and net efficiencies with heat recovery up to about 80 percent. The high operating temperature of molten carbonate fuel cells allows methane (natural gas) and steam to be internally converted to hydrogen and CO2 (internal fuel reforming). This eliminates the need for an external fuel reformer and associated air emissions. Because the high operating temperatures and ceramic components of molten carbonate fuel cells are likely to constrain startup and ramp rates, baseload power generation and cogeneration applications are likely to be the most feasible.

The key technical challenges regarding molten carbonate fuel cells have been the effect of the corrosive electrolytes and high operating temperatures on material longevity. However, in 2003, FuelCell Energy introduced the first commercial molten carbonate fuel cell, its DFC (Direct FuelCell) series, offered in 250 kW, 1 MW and 2 MW (net output) sizes. The company reports 31 pre-commercial and early commercial facilities in operation. Two are in the Northwest, including a one-megawatt demonstration unit operating on wastewater digester biogas at the King County South Treatment Plant in Renton, WA, and a two-unit 500kW natural gas fired cogeneration installation at Zoot Enterprises in Bozeman, MT.

Solid Oxide Fuel Cells (SOFC) are based on solid-state ceramic electrolytes, intended to reduce the corrosion and containment problems associated with liquid electrolytes. To achieve adequate ionic conductivity in currently available solid electrolytes, the cell must operate at about 1830^{o}F. This temperature supports internal reforming of carbonaceous fuels and could provide high-quality steam for cogeneration applications. Other potential advantages include long life (demonstration SOFCs have operated up to ten years), tolerance to fuel-borne sulfur and simplicity of design that should lead to lower production costs. However, fuel cell systems operating at this temperature would require lengthy startups and be limited to slow ramp rates.

Current solid oxide fuel cell designs consist of a magnesium-doped lanthanum manganate cathode, a dense yttria-stabilized zirconia electrolyte and a porous zirconia-nickel cermet anode. Though stacked configurations have been explored, the leading design, developed by Westinghouse in the mid-1980s, consists of a porous zirconia support tube on which are sequentially deposited the cathode, electrolyte and anode materials. Fuel (hydrogen or carbon monoxide) flows over the outer surface of the cell (the anode) and air flows through the tube in contact with the cathode. In the anode, negatively charged oxide ions ($O^{=}$), transferred through the electrolyte react with hydrogen to form water, or carbon monoxide to form carbon dioxide, releasing electrons. The electrons pass through the electrical load to the cathode where atmospheric oxygen is converted into oxide ions for transfer across the electrolyte to the anode.

Though solid oxide fuel cell research has been underway for over 40 years, commercial products are not yet available. Current research seeks to develop electrolytic material that can operate at lower temperature than current zirconia-based materials. Siemens-Westinghouse has announced the objective of introducing a commercial product by 2007.

Cost and performance estimates for various fuel cell designs are summarized in Table J-7. Except for phosphoric acid cells, the cost estimates are uncertain because of the early stage of development. The forecast reductions in electrical heat rate and installation cost shown in Table J-7 are the annual averages for the period 2005-25 based on the more detailed NREL forecasts[49]. These rates of improvement reflect assumptions of slow market penetration over the next two decades, because of the high capital and operating costs of fuel cells compared to competing technologies. No improvements are shown for phosphoric acid fuel cells because these will likely be phased out in favor of other fuel cell technologies as these are introduced to the market.

Benchmark electricity production costs for fuel cell cogeneration installations operating in load displacement mode are shown on the last line of Table J-7.

Forecast levelized lifecycle electricity production costs of fuel cell systems with full cogeneration are compared to forecast wholesale and retail power prices in Figure J-4. Most fuel cell systems during this period are largely expected to be cogeneration installations on the customer side of the meter serving to displace electrical load. Though this is the most favorable configuration with respect to electricity production cost, Figure J-4 suggests that fuel cell systems even in this configuration are unlikely to be generally cost-effective even at the end of the planning period. As with other distributed generation technologies, specific installations may prove to be cost-effective because of conditions such as substantial transmission and distribution system credit or need for premium power.

Table J-7: Cost and performance of grid-interconnected fuel cell cogeneration plants[50,51] (2005 technology base year)

	200 kW PAFC	10 kW PEMFC	200 kW PEMFC	250 kW MCFC	2000 kW MCFC	100 kW SOFC
Capital cost [52]($/kW)	$4920	$5210	$3600	$7200	$3080	$3430
O&M ($/MWh)	$27	$31	$22	$41	$31	$23
Electrical Heat Rate (Btu/kWh)	9480	11370	9750	7930	7420	7580
Net Heat Rate (Btu/kWh)[53]	5215	5830	5250	5750	5200	5210
Electrical heat rate reduction 2005-25 (%/yr)	None	-0.7%	-0.3%	- 0.5%	- 0.5%	-0.7%
Cost reduction 2005-25 (%/yr)	None	-6%	-5%	- 5%	-4%	-5%

[49] See footnote 12.
[50] Costs, heat rates from National Renewable Energy Laboratory, Gas-fired Distributed Energy Resource Technology Characterizations, November 2003.
[51] Natural gas fuel.
[52] Total installed cost, CHP configuration.
[53] Net heat rate is the total fuel energy input less the energy value of the equivalent fuel required to serve the cogeneration load (assuming 80% boiler efficiency) divided by the energy value of the electricity produced. The values shown assume full use of the available reject heat for cogeneration.

Benchmark [54]Electricity Cost ($/MWh)	$128	$116	$92	$148	$96	$90

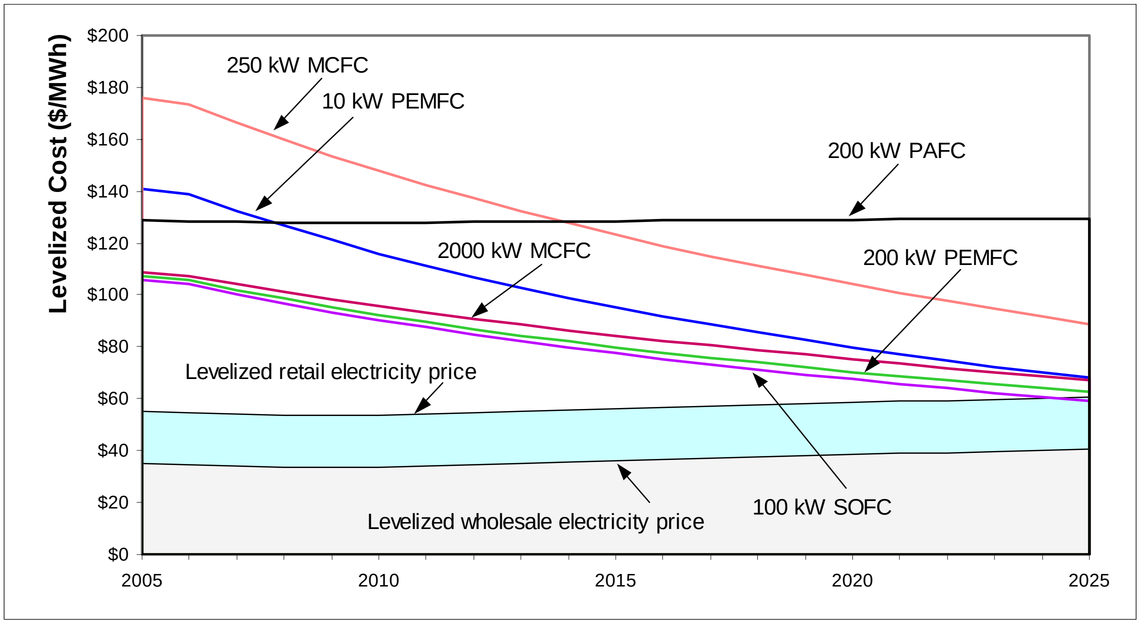


Figure J-4: Forecast levelized cost of electricity from fuel cell cogeneration plants

The products of fuel cell electrochemical reactions are water vapor (hydrogen fuel) and carbon dioxide (carbon monoxide fuel), so in theory a fuel cell produces no non-greenhouse gas air emissions. However, the external fuel reformers required for low-temperature fuel cells fuelled by carbonaceous fuels rely on the combustion of either the hydrogen contained in anode off-gas, or of the input fuel to supply energy for fuel reformation. This combustion occurs at temperatures sufficient to ensure nearly complete combustion yet not so hot that significant formation of nitrogen compounds occurs, so the process yields comparatively low emissions, typically including NOx, CO and VOCs. The emissions of production fuel cells have been sufficiently low that some commercial fuel cells have been exempted from needing individual air emission permits. Like other technologies employing carbon-containing fuels, fuel cells, unless fuelled by pure hydrogen produce carbon dioxide in proportion to the fuel carbon content and net thermal efficiency. Typical air emission rates for fuel cells operating on natural gas fuel are shown in Table J-8.

[54] Benchmark levelized electric cost, constant year 2000 dollars. Based on mixed financing (20% publicly-owned utility, 40% investor-owned utility, 40% independent, see Appendix I), 2010 service year, 20-year service life, 20-year maximum amortization, commercial natural gas, 90% capacity factor, $2/kW/yr capacity service charge and the mean value of the CO2 penalty from the portfolio analysis of this plan.

Table J-8: Air emissions of packaged stationary fuel cell systems[55]

	200 kW PAFC	10 kW PEMFC	200 kW PEMFC	250 kW MCFC	2000 kW MCFC	100 kW SOFC
NOx (t/GWh)	0.02	0.03	0.01	0.03	0.03	0.03
CO (t/GWh)	0.03	0.04	0.04	0.02	0.02	0.02
VOC (t/GWh)	0.01	0.01	0.01	0.01	0.01	0.01
CO_2 (t/GWh)	570	640	590	480	450	460

Fuel cells promise higher efficiency electricity generation, improved cogeneration opportunities and grid support with lower air emissions and greenhouse gas production. The potential applications of fuel cells for electric power generation are many, including backup power supplies, distributed packaged baseload cogeneration, distributed peak shaving and load following and central-station combined-cycle power generation. Fuel cells could also serve as a path to a hydrogen-based energy economy. However, high cost and limited durability, and the availability of suitable alternatives at less cost present severe obstacles to widespread market penetration. As noted by the US DOE in a 2003 report to Congress[56], market forces alone are unlikely to result in large-scale use of fuel cells in the next few decades because conventional power technologies meet or exceed customer requirements and expectations at lesser cost. Cost is a barrier for all fuel cell types across all applications. Cost reduction by an order of magnitude is required through reduction in the cost of constituent materials, manufacturing improvements and improvements in durability, lessening the frequency of fuel cell stack replacement.

Microturbines

Microturbines are packaged miniature gas turbine generators currently available in sizes ranging from 30 to about 250 kW. They compete with small-scale reciprocating engine-generators for generation and cogeneration applications. Though their first cost is higher and electrical efficiency lower than comparably -sized reciprocating engine-generators, microturbines offer the advantages of compactness, simplicity, quietness and lower uncontrolled air emissions. Microturbines were derived from automotive turbocharger technology and aircraft auxiliary power units, and are in the early commercial stage of development, having been introduced to the market in the late 1990's.

Microturbines can run on natural gas, biogas, propane, butane, diesel and kerosene. They are quiet and compact (a 30-kilowatt unit is about the size of a large refrigerator) and air emissions are much lower than those of uncontrolled reciprocating engines. The electrical efficiency of power-only microturbines is low, ranging from 23 to 26 percent. Cogeneration can increase the overall thermal efficiency to nearly 70 percent. Potential stationary power applications include

[55] Uncontrolled, based on electric output and heat rate. Net emissions of units equipped with cogeneration may be less because of displacement of cogeneration thermal loads. 2005 values from Fuel Cells, Table 7 of NREL, 2003
[56] U.S. Department of Energy. Fuel Cell Report to Congress. February 2003.

load-side peak shaving, premium power [57]generation, remote load service, grid support and applications involving demanding fuel such as such as landfill gas recovery. The penetration of microturbines is presently very limited, though growing, particularly in the premium power market and applications involving difficult fuels such as landfill gas and coalbed methane recovery. If costs can be reduced and reliability confirmed, microturbines could routinely serve light industrial and commercial building cogeneration loads.

A typical microturbine is a packaged module consisting of a single stage centrifugal air compressor, a recuperator[58], a fuel combustor, single stage power turbine and generator. Some designs use high-speed permanent magnet generators producing variable voltage, variable frequency alternating current (AC) power. This is electronically rectified to direct current power and then inverted to 60 Hz AC power. Some models use synchronous AC generators. Units operating off the low-pressure natural gas distribution system require fuel gas pressure boost (Fuel gas pressure boosters are typically integrated into the microturbine package). Integrated exhaust heat recovery equipment is available for hot water or low-pressure steam cogeneration loads.

Like other air breathing engines, the power output and efficiency of microturbines degrade at high ambient temperatures and elevation. Projected availability is 95 percent, or better and design life is in the 40,000 to 80,000 hour range. Commercial machines have not been in service long enough to fully confirm long-term availability or operating lifetime.

Cost and performance characteristics over a range of unit sizes for cogeneration applications with full heat recovery are shown in Table J-9. Operating and maintenance costs are based on the cost of vendor maintenance service contracts. Units operating on non-standard fuels such as landfill gas, containing halides, sulfur, acids, ammonia, salts or metallic compounds will experience higher maintenance costs and shorter equipment life.

Table J-9: Cost and performance of grid-interconnected microturbine cogeneration systems[59,60]
(2005 technology base year)

	30kW	70kW	100kW	200kW
Capital cost ($/kW)[61]	$2101	$1630	$1500	$1530
O&M ($/MWh)	$17	$13	$14	$14
Electrical Heat Rate (Btu/kWh)	15100	13500	13100	11400
Net Heat Rate (Btu/kWh)[62]	6800	7500	7300	6800

[57] Premium power is power having high reliability or quality characteristics such as a narrow voltage or frequency control bands.
[58] A recuperator is a heat exchanger that heats the compressed air using energy from the power turbine exhaust. Its purpose is to increase the efficiency of the unit.
[59] Costs and heat rates from National Renewable Energy Laboratory, Gas-fired Distributed Energy Resource Technology Characterizations, November 2003.
[60] Natural gas fuel.
[61] Total installed cost, CHP configuration.

Electrical heat rate reduction 2005-25 (%/yr)	-1.2%	-1.4%	-1.2%	-1.0%
Cost reduction 2005-25 (%/yr)	-2.3%	-2.2%	-2.5%	-3.0%
Benchmark [63]Electricity Cost ($/MWh)	$98	$91	$88	$85

The forecast reductions in electrical heat rate and installation cost shown in Table J-9 are the annual averages for the period 2005-25 based on the more detailed NREL forecasts[64]. Near-term cost reduction is expected from improved package design, expanded component suppliers and reduced manufacturing costs. Over the longer-term, cost reductions and efficiency improvements are expected from larger package sizes, ceramic components or internally cooled metallic turbines to permit higher temperature operation. Concurrent improvements in emission characteristics are expected. Benchmark 2010 electricity cost values above the slashes are for cogeneration applications with full heat recovery.

Forecast levelized lifecycle electricity production costs of microturbine cogeneration systems are compared to forecast wholesale and retail power prices in Figure J-5. Most microturbine installations during this period are expected to be cogeneration installations on the customer side of the meter serving to displace electrical load. At forecasted rates of cost and heat rate reduction it appears unlikely that microturbine cogeneration systems will become generally cost-effective during the period of this plan. As with other distributed generation technologies, specific installations may prove to be cost-effective because of conditions such as substantial transmission and distribution system credit or need for premium power.

[62] Net heat rate is the total fuel energy input less the energy value of the equivalent fuel required to serve the cogeneration load (assuming 80% boiler efficiency) divided by the energy value of the electricity produced. The values shown assume full use of the available reject heat for cogeneration.

[63] Benchmark levelized electric cost, constant year 2000 dollars. Based on mixed financing (20% publicly-owned utility, 40% investor-owned utility, 40% independent, see Appendix I), 2010 service, 10-year service life, 10-year maximum amortization, commercial natural gas supply, 90% capacity factor, $2/kW/yr capacity service charge and the mean value of the CO2 penalty from the portfolio analysis of this plan.

[64] See footnote 12.

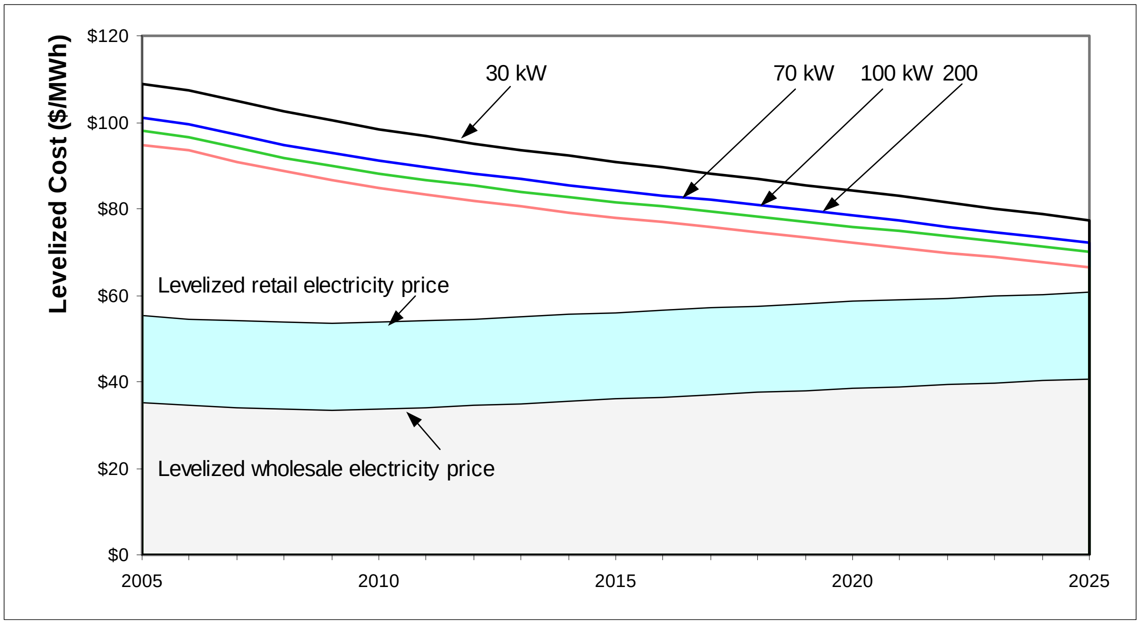


Figure J-5: Forecast levelized cost of electricity from microturbine cogeneration systems

Nitrogen oxides (NOx), carbon monoxide (CO) and unburned hydrocarbons (VOC) are the principal emissions of concern for microturbines fuelled by natural gas. Microturbines typically incorporate lean premixed ("Dry low-NOx") combustion technology but to date no post-combustion control of emissions. This approach, though producing higher emission levels than most new gas-fired combined-cycle plants, complies with the emission standards typically applying to distributed generation installations. Post-combustion catalytic combustors and improved conventional combustors are expected to lead to lower CO and NOx emissions.

Table J-10: Representative air emissions from microturbines[65]

	30kW	70kW	100kW	200kW
NOx (t/GWh)	0.30	0.27	0.28	0.26
CO (t/GWh)	0.82	0.16	0.29	0.16
THC[66] (t/GWh)	<0.10	<0.10	<0.10	<0.10
CO_2 (t/GWh)	800	760	690	670

[65] Uncontrolled, based on electrical heat rate. Net emissions of units equipped with cogeneration may be less because of the displacement of cogeneration thermal loads. 2005 values from Microturbines, Table 6 of NREL, 2003.
[66] Total hydrocarbons.

Stirling engines

A Stirling engine is a closed-cycle external combustion reciprocating heat engine. A basic Stirling engine consists of a cylinder containing a power piston at one end (hot end) and a displacer piston at the other (cold end). The two ends of the cylinder are externally connected by a gas transfer pipe in which is located a regenerator containing porous heat storage media. The ends of the cylinders, the transfer pipe and the regenerator contain an inert gaseous working fluid, optimally hydrogen or helium. Energy is continuously supplied to the exterior of the cylinder on the power piston side of the regenerator by a fuel combustor or other high temperature heat source. The cylinder on the displacement piston side of the regenerator is chilled by a reject heat removal system. The two pistons move to sequentially compress, heat, expand and cool the working fluid. The regenerator stores energy between the cooling and heating segments of the cycle, improving the efficiency of the engine. The power produced by expansion is greater than the power required for compression; the difference (less frictional losses) constitutes the power output of the engine. The power piston can drive a linear electric generator or through linkages, provide rotating mechanical power. Commercial models currently employ conventional rotating generators driven through linkages. Reject heat from the cold end cooling system and waste heat from the fuel combustor can be recovered for cogeneration applications. (The operation of a Stirling engine is not intuitive. Animated illustrations of Stirling engine operation can be accessed on the web at sites such as StirlingInfo.com at http://chatfaces.com/stirlinginfo/StirlingInfo.htm.)

First patented in 1816 by the Rev. Dr. Robert Stirling for the purpose of driving mine pumps, the Stirling engine has only recently entered the power generation market. Research and development has been underway for nearly seventy years for applications including automotive propulsion, remote power systems, space power systems, solar-electric plants and more recently micro-CHP applications. At present, the research and development efforts are focusing on solar thermal Stirling dish and micro-CHP applications. Key barriers to commercialization have been the development of durable seals, stress and corrosion of hot end materials and blockage of the regenerator media.

Micro-CHP packaged units employing Stirling engines are approaching early commercial status. Whisper Tech of New Zealand, has announced that it will be supplying 550 of its "WhisperGen home energy systems for a market trial installation in a residential development in East Manchester, UK. WhisperGen units for grid-connected applications use a four-cylinder, natural gas fuelled Stirling engine driving a 1.2-kilowatt generator. The unit, about the size of a residential washer, can supply over 27,000 Btu/hr for space or hot water heating. Commercial introduction is expected in 2005. In the US, STM Power has introduced a 55kW package unit suitable for natural gas or biogas operation. These units can supply up to 310,000 Btu/hr for space or hot water heating. In the Northwest, a commercial STM 55kW PowerUnit is planned for installation at the Corvallis wastewater treatment plant for operation on wastewater treatment plant biogas. A demonstration unit is also planned for operation on landfill gas at the Coffin Butte landfill gas energy recovery facility.

Stirling engines promise high thermodynamic efficiency, low emissions, quiet operation and the ability to utilize a wide variety of fuels. Because fuel combustion is continuous and external to the engine, the fuel combustor of a Stirling engine can be designed for optimal combustion and emission control for specific fuels. A wide variety of combustible fuels, as well as direct heat sources such as solar radiation, radioisotopes and high temperature reject heat from industrial processes can be used as the energy source. The initial market for Stirling engines may be applications using fuels such as corrosive biogases. If costs decline, applications such as residential CHP requiring quiet operation and low emissions may become attractive. The electrical efficiency of currently available Stirling engines is reported to be between 28 and 30% (11,400 - 12,200 Btu/kWh). This is comparable to small gas turbines and reciprocating internal combustion engines. However, the Stirling thermodynamic cycle offers the potential for ultimately higher electrical efficiencies than either gas turbines or internal combustion reciprocating engines. Full use of reject heat for cogeneration loads would result in a net heat rate of about 4600 Btu/kWh.

Cost information from early commercial installations suggests that the installed costs of small packaged Stirling CHP units are currently about $2000/kW [67]. Operating costs for the STM 55kW package appear to be approximately $13/MWh, excluding property tax and insurance, over a ten-year product lifetime. NREL estimates average annual cost reduction of 2.8% and heat rate reduction of 1.4% for the period 2005-30. The resulting benchmark power costs are $128/MWh (power-only) and $77/MWh (full CHP). Estimates of the future cost of Stirling engine-generators are highly uncertain for several reasons. Early-commercial capital costs are unlikely to be representative of mature product prices. On one hand, manufacturers often discount early installations to encourage placement. On the other, substantial production cost reductions may follow successful commercialization. Also, the lack of long-term operating experience and the high failure rates of early designs renders operating and maintenance costs uncertain as well.

Forecast levelized lifecycle electricity production costs of packaged Stirling engine cogeneration units with full heat recovery are compared to forecast wholesale and retail power prices in Figure J-6. Most installations during this period are expected to be cogeneration installations on the customer side of the meter serving to displace electrical load. At forecasted rates of cost and heat rate reduction it appears possible that packaged Stirling engine cogeneration systems in load displacement configuration may become generally cost effective towards the end of the period of this plan. Stirling engine units may find earlier application with difficult fuels such as landfill gas and wastewater treatment plant gas where the customized fuel handling and emission control capability facilitated by external combustion may prove attractive.

[67] Oregon Energy Trust.

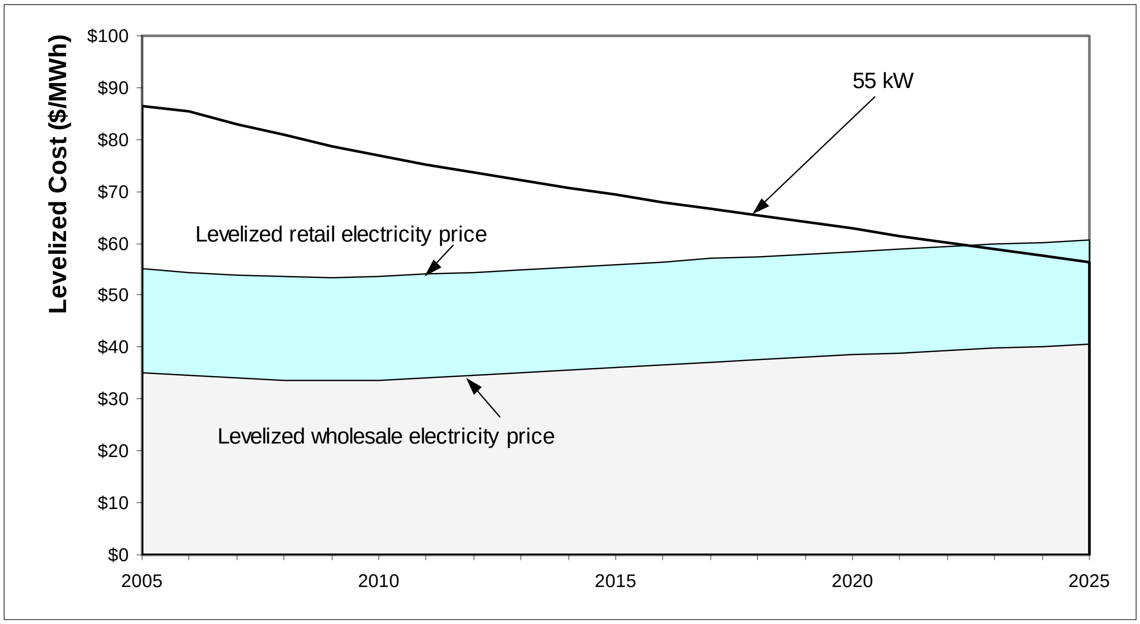


Figure J-6: Forecast levelized cost of electricity from a Stirling engine cogeneration system

Because fuel combustion is external and continuous, the fuel combustor of a Stirling engine can be designed for optimal combustion and emission control for specific fuels. Uncontrolled emissions from the STM PowerUnit are reported by the manufacturer to be as follows: NOx - 0.5 lb/MWh , CO - 1 lb/MWh, VOC - < 0.1 lb/MWh and CO2 - 1480 lb/MWh.

Example Northwest cogeneration project proposals

During development of this power plan, the Council was supplied with on proforma information on several proposed Northwest cogeneration projects. These are described in Table J-11 to provide "real world" comparison to the generic technology characteristics described above. The benchmark electricity costs shown in Table J-11 were developed for these examples using the Council's forecast fuel prices and other assumptions of the portfolio analysis.

Table J-11: Example regional cogeneration project proposals

Project	Capital ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Fuel	Fuel Price/Escalation[68] ($/MMBtu/%/yr)	Heat Rate (Btu/kWh) (electrical/net)	Electricity Cost ($/MWh)[69]
48 MW gas turbine generator with heat recovery steam generator supplying pulp and paper mill process steam load. No steam turbine generator.	$860	$65	$5.00	Natural gas	$4.70/0% (NPCC industrial gas forecast)	9550/5280	$47
500 kW reciprocating engine with heat recovery supplying a hospital water heating load	$2220	$9	$12.50	Natural gas	$7.25/0% (NPCC commercial gas forecast)	9350/4920	$73
8.5 MW gas turbine generator with heat recovery steam generator supplying institutional space conditioning load. No steam turbine generator.	$2420	$150	$7.15	Natural gas	$7.25/0% (NPCC commercial gas forecast)	13,300/6000	$94
100 kW microturbine with heat recovery supplying office building hot water and space conditioning loads	$1490	Incl. in variable O&M cost	$15.00	Natural gas	$7.25/0% (NPCC commercial gas forecast)	13,130/7300	$127

[68] Forecast 2010 price in year 2000 dollars. Average annual escalation 2010-2025.
[69] Benchmark electricity 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. Except for microturbine, cost as delivered to local grid including $2/MWh ancillary service charge. Microturbine assumes load displacement, no ancillary service charge. 90 percent capacity factor. CO_2 penalty set at the mean of the portfolio analysis, as applicable. Cogeneration costs are based on fuel charged to power heat rate.

The first example appears to be clearly competitive with retail power costs and marginally competitive with forecast wholesale power costs. The second example is marginally competitive with forecast typical retail prices. In this case, savings from avoided retail power purchases and possible local benefits such as offset transmission and distribution system costs or reliability improvements, may add sufficient value to justify the project. The remaining examples would be difficult to economically justify unless exceptional locational values were present.

PROSPECTS FOR DEVELOPMENT OF COGENERATION IN THE NORTHWEST

About 3640 megawatts of cogeneration is currently installed in the Northwest. Approximately 1240 megawatts of this capacity is "industrial" cogeneration, where the power plant is closely integrated with the host facility and sized to the thermal load. The remaining 2400 MW consists of utility-scale combined-cycle plants at which a portion of the steam from the heat recovery steam generator is bled (at full pressure or from extraction taps on the steam turbine) to serve a thermal load. Operation of industrial cogeneration is largely dictated in the short-term by thermal demand, and over the longer-term by the economic competitiveness of the host facility (approximately 150 MW of the industrial capacity is currently idle or on standby). Operation of utility-scale cogeneration is largely determined by fuel and electricity prices.

Industrial cogeneration dates to the early days of electricity use, before the development of efficient long-distance transmission and emergence of remote central station generation. Cogeneration was especially common in forest products industries where low cost wood residues were readily available for fuel. Cogeneration by utility-scale plants is a more recent phenomenon dating to the emergence of reliable low-cost, easily sited gas-fired combined-cycle plants in the late 1980s. Some industrial cogeneration and much of the utility-scale capacity has been installed in the past decade. Recently installed industrial cogeneration capacity is predominantly gas-fired gas turbine generators with heat recovery steam generators though at least two new boiler-steam turbine generator plants and one plant using reciprocating engine generators have been installed within the past several years.

Assessment of Northwest cogeneration potential

An assessment of regional cogeneration potential was made using the Cogeneration Regional Forecasting Model (CRFM). The CRFM was developed for the Bonneville Power Administration and used in the development of previous power plans. The CRFM simulates the economic benefits of cogeneration for the most likely host facilities[70]. The cogeneration potential for each category of facility is scaled using facility population estimates to derive an estimate of regional cogeneration potential.

In the CRFM, the Pacific Northwest is divided into 23 sub-regions, differentiated by energy prices, climate zones, and utility service territories. Up to 25 types of potential industrial and commercial cogeneration host facilities are characterized, based on the magnitude and patterns of

[70] A "host facility" is an industrial or commercial facility (and perhaps ultimately, residences) with heating or cooling loads that might be served by cogeneration.

electrical and thermal energy use. These are shown in Table J-12. Four size categories representing energy consumption levels are defined for each type of host facility[71].

The model attempts to size and match a cogeneration technology with each of the 2300 host facility categories, using cost and performance data for various technology and size options. These included reciprocating engine-generators with and without chillers, arrays of reciprocating engine-generators with and without chillers, gas turbine generators with and without chillers, steam turbine generators and molten carbonate fuel cells. The model is also provided with forecasts of fuel prices and wholesale and retail electricity prices. Using this data and minimum thermal load and energy savings criteria, the model performs rate of return analyses to determine the most promising cogeneration system (technology type, size and operating mode), if any, for each facility type for each of several rates of return. Applications not meeting minimum energy savings and rate-of-return criteria are discarded, yielding cogeneration potential as a function of internal rate-of-return for each host facility category. The economic cogeneration potential is calculated for each host facility category using a weighting function based on assumptions regarding penetration (decisions to proceed with installation) at different rates-of-return. Sub-regional economic cogeneration potential is obtained by multiplying the weighted economic potential for each facility category by the host facility population for each sub-region less existing cogeneration installations. Regional potential is obtained by summing sub-regional estimates.

A supply curve of cogeneration can be constructed by estimating economic potential at various electricity prices. However, this assessment sought an estimate of economic potential at the forecast Mid-Columbia wholesale prices of Appendix C. Cogeneration systems were assumed to first displace host facility electrical load valued at retail rates based on the Mid-Columbia wholesale power price forecast; electricity surplus to host facility loads was assumed to be sold back to the servicing utility at the forecast wholesale price. In practice, some small-scale cogeneration facilities may be able to sell back surplus electricity at retail rates because of state net metering requirements. This potential was not assessed in this study because net metering is generally limited to much smaller facilities than those considered here. In addition, some cogeneration facilities may be able to obtain location-specific transmission, distribution or system reliability credit in addition to the wholesale value of surplus power. Because it is location-dependent the potential could not be estimated in this analysis.

Because only a limited number (25) of technology type-size-fuel options can be considered during a model run, the technologies described earlier in this appendix were screened for potential cost-effectiveness prior to the base case runs. The smallest (1 megawatt class) gas turbine generators, 250 kW class molten carbonate fuel cells, solid-oxide fuel cells and Stirling engines proved not to be cost-effective through 2025 and were omitted from the final analysis. Because this analysis was intended to identify “thermally-matched” cogeneration potential, combined-cycle technology was also omitted. Because cogeneration is largely incidental to the size and economics of these plants, their inclusion could lead to meaninglessly large estimates of potential cogeneration capacity, concealing applications where thermally-matched cogeneration may be economic.

[71] In practice, the host facility populations of most sectors are allocated to size classes based on employment (industrial sectors) or floor area (commercial sectors) because of the lack of sufficiently detailed energy consumption data.

Because of resource limitations and lack of data, the populations of most classes of potential host facilities and existing cogeneration installations were not updated from the 1995 base values used for the 4th Power Plan. However, because of its large cogeneration potential, the population of Paper sector facilities, and existing cogeneration in this sector was updated to 2002, the latest year currently available.

The final analysis used the following assumptions:

Fuel prices	5th Plan forecast, Medium cases
Technology options	Natural gas-fired reciprocating engine-generators Natural gas-fired reciprocating engine-generators w/chillers Natural gas-fired gas turbine generators Natural gas-fired gas turbine generators w/chillers Biomass residue-fired steam-electric generators (wood products and chemical pulping sectors only) Molten-carbonate fuel cells
Project financing	5th Plan assumptions for private developers (private sectors) 5th Plan assumptions for public developers (public sectors)
Surplus electricity sell-back rate	5th Plan forecast Mid-Columbia wholesale prices
Standby charges	$2/kW/yr
Carbon dioxide penalty (natural gas projects)	Levelized mean annual values of the portfolio analysis
Renewable resource incentives (biomass residue projects)	Federal production tax credit at levelized mean annual values of the portfolio analysis Green tag revenue at mean annual values of the portfolio analysis
Host facility decision criteria	20% minimum energy savings % of technical potential proceeding at given rate of return: 10% @ 10%; 15% @ 15%; 20% @ 20%; 30% @ 25%; 45%@ 30%; 60% @ 35%; 85% @ 40%

Under these assumptions, an estimated 1050 megawatts of potential cogeneration capacity is available for development in the Northwest. This capacity would produce from 840 to 945 average megawatts of electricity at the 80 to 90 percent capacity factors typical of cogeneration plants. Nearly 60 percent of the potential is in the Paper sector (Table J-12) and 80 percent of is concentrated in three sectors - Paper, Chemicals and Petroleum and Universities. The potential shown in the Wood sector is based on the incremental cost of adding backpressure turbines to an existing boiler steam cogeneration system fired by wood residues. Because this opportunity is not available at all sites, this potential is not included in the total.

The estimates of economic potential appearing in Table J-12 are best viewed as order-of-magnitude approximations. As described earlier, other than the paper sector, the regional populations of host facilities were not updated from the 1995 levels used for the 4th Power Plan. Furthermore, because of lack of readily available information, future growth rates were set to zero so the inventory of potential host facilities remains constant, whereas the population of the various sectors have and will continue to change. Food, for example, declined about 3% per year on average in terms of gross state product between 1995 and 2003. This suggests that the current potential in the food sector is somewhat over-estimated and may decline in the future. Though the inventory for the paper sector was updated to 2002 for this assessment, the average annual decline of 4.6 percent between 1995 and 2003 in terms of gross state product, suggests that the future cogeneration potential of this sector may be less than forecast here. In contrast, the chemical and petroleum sectors grew at a weighted average annual rate of 5.7% between 1995 and 2003, suggesting that both the current and future potential of these sectors are underestimated.

Table J-12: Estimated economic potential for new cogeneration

Sector	Base Case (MW)	System Types
Food	70	IC, IC w/chiller
Wood	(110[72])	ST (BPT only)
Paper	650	IC, IC Array
Chemical & Petroleum	100	IC, IC Array
Rubber & Plastic	<10	IC
Stone, Clay, Glass		
Primary Metals		
Fabricated metal products	<10	IC
Transportation equipment	10	IC
Refrigerated warehouses		
Large federal facilities	60	IC, IC w/chiller, GT
Restaurants		
Retail trade		
Offices		
Lodging	<1	IC w/chiller
Laundries		
Nursing homes		
Hospitals	60	IC, IC w/chiller
Schools		
Universities	80	IC w/chiller, GT
Correctional institutions	10	IC, IC w/chiller, IC array
Multi-family housing		
Other industries		
Total	1050	

Reciprocating engines are the predominant cogeneration technology selected by the model. This reflects both the recent and forecast improvement in this technology and the availability of a wide range of plant sizes afforded by the ability to cluster units. None of the advanced technologies (fuel cells, microturbines or Stirling engines) proved to be economical. This was not unexpected given the comparison of forecast benchmark costs to electricity prices shown in Figures J-1 through J-6. In practice, these technologies may be able to compete for applications involving challenging fuels or at locations where the noise, vibration or other adverse environmental characteristics of conventional technologies are not acceptable.

[72] Wood sector potential assuming the incremental cost of backpressure steam turbines on existing boiler-steam cogeneration systems.

The findings of this assessment appear to be supported by recent study by Energy and Environmental Analysis, Inc. for Oak Ridge National Laboratory of cogeneration potential in US DOE Region 10 (Alaska, Idaho, Oregon and Washington)[73]. That study, which used base case assumptions reasonably comparable to those of this assessment, estimated a base case economic potential of 1191 MW for Idaho, Oregon and Washington. Also, though state-level breakouts by technology type were not provided, the observation of the Oak Ridge study that "…the cost and performance of emerging technologies like microturbines and fuel cells, are predominantly outside of a competitive range." is consistent with the findings of this assessment.

Barriers to the development of cogeneration

There appears to be more than 1000 megawatts of new economic cogeneration potential in the Northwest. Most of this potential exists in the traditional industrial sectors, including food, paper, chemicals and petroleum. Additional potential exists in the wood products and paper industries where low-cost bioresidue fuels are available and opportunities exist for adding backpressure or extraction steam turbine generators to steam boilers provided for servicing thermal loads. However, with the exception of the chemicals sector, all of these sectors continue to decline in terms of gross state product, perhaps reducing cogeneration opportunities below the levels forecast here. Continued improvement in the energy efficiency of thermal production processes will also slowly reduce cogeneration potential. Offsetting these reductions will be continued improvements in cogeneration technology that should lead to an expansion of feasible applications.

Most of the remaining potential is located in a few commercial sectors with large thermal loads including large federal facilities such as military bases, universities and hospitals.

The cost and performance of emerging cogeneration technologies (fuel cells, microturbines and Stirling engines) are expected to rapidly improve. Despite this, it appears that the conventional technologies (reciprocating engines, gas turbines and steam turbines) are likely to remain the most economic choice for most cogeneration applications for the planning period. The conventional technologies are relatively inexpensive, reliable, and readily available in a variety of sizes and configurations. They have improved greatly in recent years, particularly with respect to emissions, and will continue to improve in the future. The new technologies are unlikely to be cost competitive for many years so will have to compete on features. Ability to utilize difficult fuels, quiet operation, little routine maintenance and compact, small unit size appear to be features that could provide entrée to the cogeneration market for these technologies.

Benefits of cogeneration include more efficient use of energy resources, reduced environmental impacts, improved economic viability of the host facility, improved system reliability and reduced transmission and distribution system costs. Unfortunately, the range of benefits is rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop cogeneration. Many of the barriers to cogeneration stem from these differing perspectives. Some of the more significant barriers include:

[73] Energy and Environmental Analysis, Inc. *Combined Heat and Power in the Pacific Northwest: Market Assessment*. July 2004.

- The return on investment requirement of the host facility is often higher than that of a utility.
- Unless the utility participates in the capital investment, the utility sees no return and the cogeneration energy is equivalent to loss of load.
- Limitations on the availability of capital often constrain the ability of a host facility to develop cogeneration opportunities.
- Where energy is not a significant expense to the host facility, energy savings benefits may not be worth the hassle of installing and operating a cogeneration plant.
- Uncertainties regarding the economic viability of the host facility may result in unacceptable investment risk.
- The locational value of cogeneration is often not reflected in electricity buy-back prices.

A June 2003 workshop hosted the Council identified impediments to the development of cogeneration and distributed generation that could be remedied through institutional actions. 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.

OTHER DISTRIBUTED GENERATION TECHNOLOGIES

Solar photovoltaic power generation systems

Solar photovoltaic power generation systems are based on photovoltaic cells, large area semiconductor diodes that produce direct current (DC) electricity from incident light. A variety of cell designs have been developed and can be classified by substrate, photosensitive material and structure. The predominant types by gross structure are wafer cells, thin film cells and ribbon-grown cells. In 2003, wafer cells comprised about 89% of global production. Thin-film cells comprised about 10% and ribbon cells about 1%.

Wafer cells are produced by sawing 10 to 15 cm diameter ingots of high-purity mono-crystalline or polycrystalline silicon into wafers about 0.3 mm thick. The wafers are machined flat, trimmed to shape and doped to establish semi-conductor characteristics. Electrical contact grids are applied to the front and back, and the cell is coated or etched to improve light absorbance. The completed cell produces about 1.5 to 3 watts of power at rated incident radiation. Wafer cells are typically assembled into flat plate modules, backed by polyvinyl fluoride film, faced with tempered glass and cased with a metal or plastic frame. Most commercial crystalline silicon modules are rated between 50 and 200 watts. The ultimate potential efficiency of crystalline solar cells is in the 29 to 30% range. Record laboratory efficiencies of 23 to 24% (unconcentrated sunlight) have been achieved and current production modules achieve DC efficiencies of 15 to 17% (alternating current (AC) system efficiencies are lower because of inverter losses). The price of photovoltaic modules using crystalline silicon wafer technology has been stable for several years in the range of $2.25 to $3.50 per watt. Though reduction in the cost of crystalline silicon cells is hampered by inherently expensive batch production, improvements in cell efficiency and fabrication are expected to lower cell prices to about $2 per watt by 2010[74].

Thin-film technology is based on the deposition of thin layers of photosensitive materials on inexpensive support materials. Many industry observers expect thin film cell to ultimately dominate photovoltaic cell production because of lower materials consumption and a physical structure suitable for large-scale automated continuous production. The physical flexibility of some thin-film substrates presents a further advantage in that cells can be bonded to non-rigid or curved surface building components. A variety of thin-film cell designs have been developed including those using amorphous (non-crystalline) silicon, microcrystalline silicon, polycrystalline silicon on glass and chalcongenide semiconductors[75]. Amorphous silicon currently dominates thin film cell production. While the theoretical efficiency limit of single junction thin-film cells is 28%, efficiencies achieved are much lower. Furthermore, the efficiency of thin-film devices declines following exposure to sunlight, generally stabilizing at about 80% of the initial efficiency. Record laboratory efficiencies of single-junction thin film cells range from about 13 to 16 percent (stabilized, unconcentrated sunlight). The stabilized efficiency of commercial modules using thin-film cell technology currently ranges from 4 to 10%[76]. In an effort to improve the relatively low efficiency of thin-film designs, cells consisting of multiple layers (multijunction cells), each sensitive to a segment of the solar spectrum have been developed. Amorphous silicon thin-film cells are widely used in consumer products such as watches and calculators. Flat plate modules using thin-film technology are commercially available and building-integrated products using thin-film technology are rapidly entering the market. The price of flat plate modules using thin-film technology Currently ranges from $1.20 to $2.00 per watt and are forecast to decline to about $0.75 - 1.30 per watt by 2010[77]. Building-integrated products are more expensive because of the additional cost of the underlying product.

Ribbon cells are produced by continuously growing a ribbon of polycrystalline silicon of the desired cell width. The ribbon is cut into segments to create the cell blanks. The continuous

[74] Maycock, P. American Solar Energy Society Annual Conference. Portland, OR. July 2004.
[75] Based on compounds of the chalcogen elements oxygen, sulfur selenium and tellurium.
[76] Green, M.A. "Thin film photovoltaics" in Advances in Solar Energy, Vol 15. American Solar energy Society. 2003.
[77] Maycock, P. American Solar Energy Society Annual Conference. Portland, OR. July 2004.

production process and reduction in sawing time and material waste are expected to improve the cost-competitiveness of crystalline silicon cell technology.

Photovoltaic power systems can be based on flat plate modules, building-integrated products or concentrating modules. Flat plate modules, in all but the smallest systems are assembled into arrays ranging in capacity from several hundred watts to hundreds of kilowatts. These are customarily land or roof-mounted on stationary racks but are occasionally mounted on tracking devices to improve solar radiation capture. Building-integrated photovoltaic products include shingles, roofing tiles, semitransparent glazing, sunshades and spandrels. These provide improved aesthetics and installed costs less than the sum of the installed cost of separate building products and photovoltaic modules. Somewhat compromised output is common to building-integrated installations as the architecture and orientation of the building may result in sub-optimal angles of incidence. Typical building-integrated installations range from several kilowatts to several megawatts of capacity. Concentrator photovoltaic technology uses lenses to focus and intensify sunlight on high-quality crystalline silicon photovoltaic cells. Unlike flat plate modules or building-integrated products, concentrator modules can use only direct beam solar radiation so are mounted on tracking devices to follow the sun. The potential advantage over other photovoltaic technologies is the ability to leverage the cost of expensive but highly efficient photovoltaic cells against a lower-cost concentrator system. Relatively few concentrating photovoltaic systems are in operation.

A typical grid-connected photovoltaic power generation system consists of an array of flat-plate modules or building-integrated photovoltaic products, collector wiring, a DC disconnect, an inverter to convert the DC module output to alternating current (AC), an AC grid disconnect protective relays and metering equipment. Grid-independent systems need no grid disconnection equipment and may not have inverters if loads are DC, but may include batteries, charge controllers and backup generation equipment.

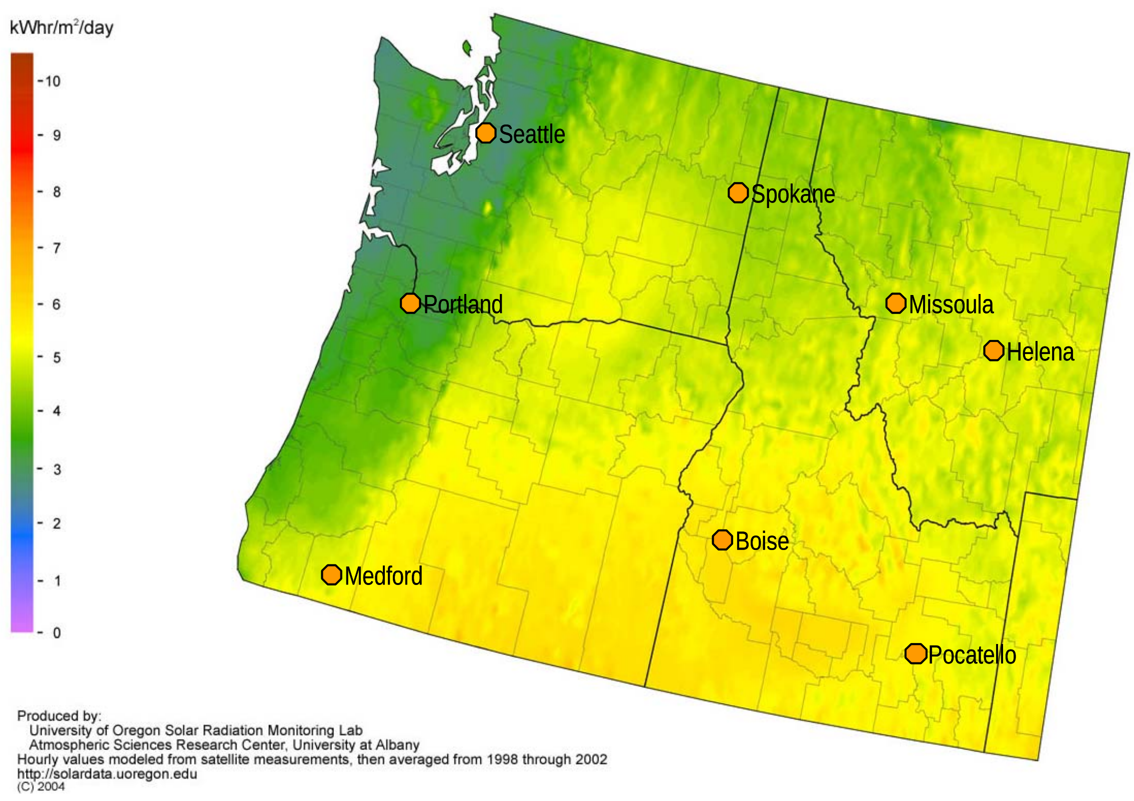
Modules typically comprise 50 to 60 percent of the cost of a fully installed system. At the prices cited above, the installed cost of crystalline silicon flat-plate systems should range from about $4200 to $7000 per kilowatt. This is consistent with the International Energy Agency (IEA) reported range of $4500 to $7000 per kilowatt for US systems[78], but lower than the $8000 - 10,000 per kilowatt prices reported by the Oregon Energy Trust in 2003[79]. The actual installed costs of systems supported by Trust funding are closer to the IEA estimates: $6420 per kilowatt for grid-connected residential systems averaging 2.8 kW capacity and $7350 per kilowatt for commercial systems averaging 6.9 kW in capacity (mixed 2003 and 2004 dollars). Economies of scale can result in lower cost for larger systems; for example, the IEA reports the cost of systems larger than 50 kW as 14 percent lower than systems averaging 2.4 kW. The higher cost of the larger commercial systems supported by Oregon Energy Trust funding may result from inclusion of several building-integrated systems. For example, the installed cost of European façade-integrated photovoltaic systems is reported by the IEA to range from $7300 - $12900 per kilowatt compared to a range of $6000 - $9500 for roof-mounted systems[80]. Also, the cost of

[78] International Energy Agency. Renewables for Power Generation. 2003.
[79] Energy Market Innovations (EMI). Oregon Photovoltaic Market Characterization. Oct 2003.
[80] International Energy Agency. Renewables for Power Generation. 2003, p56.

residential-scale systems might have dropped relative to large commercial systems as a result of standardization.

Annual operation and maintenance costs for photovoltaic systems are estimated by the IEA to be 1 to 3 percent of installed capital cost. Modules are very reliable and largely maintenance-free; the bulk of O & M costs result from inverter and battery (for stand alone systems) replacement every five to ten years[81]. Modules are expected to last the life of the system, 20 to 30 years. Improvement in inverter durability is key to reducing O&M cost.

Solar photovoltaic system productivity is a function of the quality of the solar resource, the conversion efficiency of the system and siting factors such as orientation and shading. The solar resource at a site is a function of latitude, atmospheric conditions (primarily cloud cover) and shading. The highest resource potential in the Northwest is east of the Cascades especially in southeastern Oregon and southwestern Idaho (Figure J-7). These areas receive about 75 percent of the annual solar radiation received at Barstow, California, one of the best sites in the United States. The solar radiation in the Northwest, however, has a more pronounced summer peak due to latitude[82].



[81] International Energy Agency (IEA). Renewables for Power Generation. 2003, p57.
[82] Additional maps of solar radiation in the Northwest, including monthly plots are available from the University of Oregon Solar Radiation Monitoring Lab, http://solardata.uoregon.edu.

Figure J-7: Pacific Northwest annual direct normal solar radiation

Estimates of the expected AC productivity of 5-kilowatt grid-connected solar photovoltaic systems, located at selected Northwest population centers are shown in Table J-13. These estimates were developed using the PVWATTS performance calculator for grid-connected solar photovoltaic systems. PVWATTS was developed by the National Renewable Energy Laboratory and is available at http://rredc.nrel.gov/solar/codes-algs/PVWATTS.

Table J-13: Productivity of 5kW silicon cell flat plate solar photovoltaic systems[83] at selected Pacific Northwest locations

Location	Annual Energy Production (kWh)	Annual Capacity Factor (%)
Boise	8604	20%
Helena	7949	18%
Medford	7908	18%
Missoula	7142	16%
Pocatello	8456	19%
Portland	6428	15%
Seattle	6124	14%
Spokane	7454	17%

The productivity of systems supported by the Oregon Energy Trust has been lower than the values estimated by PVWATTS. The average capacity factor of residential systems has been 10 percent and commercial systems, 12 percent. Factors leading to the lower productivity of actual systems may include the use of lower efficiency building-integrated systems based on amorphous silicon technology (the estimates of Table J-13 are based on crystalline silicon cells), sub-optimal building orientation and shading.

Photovoltaic systems produce no air emissions or water releases in operation. Concerns have been voiced about the energy and material input required to manufacture photovoltaic modules, toxic constituents of some cell designs and the land use impacts of future utility-scale systems. About two to four years are required to recover the energy currently needed to manufacture photovoltaic systems. Over a 30-year life, current photovoltaic systems provide an energy payback ratio of 7.5 to 15. While low compared to windpower (80 to 120), this is comparable to coal-fired power plants (11 to 16). Cell efficiency and manufacturing process improvements are expected to increase energy payback ratios to 15 to 30; still low compared to wind, but much better than coal. Certain chalcongenide cell designs employ cadmium and other toxic materials. The possible release of these materials to the environment through disposal of failed or obsolete modules has not been of great concern because of the limited market penetration of these technologies (outdoor cadmium telluride cells comprised 0.4 percent of global cell production in 2003). Should cells containing toxic material assume a greater market share, special efforts to ensure proper disposal of modules at end of life may be desirable (toxic materials present little problem during operation because they are encapsulated in the cell structure). In the near-term

[83] Based on the AC output of an unshaded grid-connected crystalline silicon photovoltaic system with modules installed at a fixed tilt equal to latitude.

it appears that most photovoltaic projects will be located on existing structures, so land impacts will be modest. However, the land use of possible future utility-scale plants could be substantial. Ground-mounted photovoltaic systems are estimated to directly disturb about 25 to 30 acres of land per average megawatt of energy production assuming that the system is installed in a prime solar resource area (as such systems presumably would be). In comparison, approximately 2 to 3 acres of land are typically directly disturbed (tower footprint, access roads, transmission line right-of-way, etc.) per average megawatt of wind energy. However, the total land encompassed by a wind project could range from 20 to 50 acres per average megawatt of wind energy.

Compared to the retail rates against which most photovoltaic systems are likely to compete for the foreseeable future, the cost of power from solar photovoltaic systems is currently very high. Benchmark electricity costs, calculated on the same basis as benchmark costs appearing elsewhere in this appendix, are provided in Table J-14. Though installed system prices are reported to have declined significantly in Europe over the past several years, US prices appear to have been stable, reputedly because of strong overseas demand, lack of investment in automated large-scale cell and module production facilities and the inflationary effects of subsidy programs. Over the longer-term, prices are expected to decline fairly rapidly on average for reasons including cell efficiency improvements, expansion of and improvements to cell and module production facilities, system standardization and improved installation practice. The Council assumes that these factors will lead to an average effective price decline (net of efficiency improvements and module cost reduction) of 8% annually for the period of this plan. The implied learning rate of 20 percent is generally consistent with forecasted increases in production and reductions in module cost. The effect of this learning rate on the cost-effectiveness of photovoltaic systems is shown in Figure J-8.

The building-integrated system costs of table J-14 do not include credit for the avoided cost of the building materials displaced by the photovoltaic materials. The amount of the credit is highly variable. Substitution of photovoltaic materials for high-cost building materials such as stone could result in substantially reducing the net cost of the system. Conversely, substitution for low-cost material such as composition roofing would have relatively little effect on net system cost.

Table J-14: Costs and performance of solar photovoltaic systems (2005 technology base year)

	Residential, Rooftop (3kW Flat Panel)	Commercial, Rooftop (50kW Flat Panel)	Commercial, Building-Integrated (50kW)
Capital cost[84] ($/kW)	$6000	$5200[85]	$9400/8460
O&M cost[86] ($/kW/yr)	$120	$104	$188/169
Capacity Factor (%)	10%	15%	12%
Benchmark Electricity Cost	$328	$188	$432

[84] "Overnight" full system installation cost (no financing charges).
[85] Based on 14% bulk pricing discount observed in (IEA). Renewables for Power Generation. 2003, p67.
[86] Assuming 2% of overnight capital cost per year.

($/MWh)[87]			

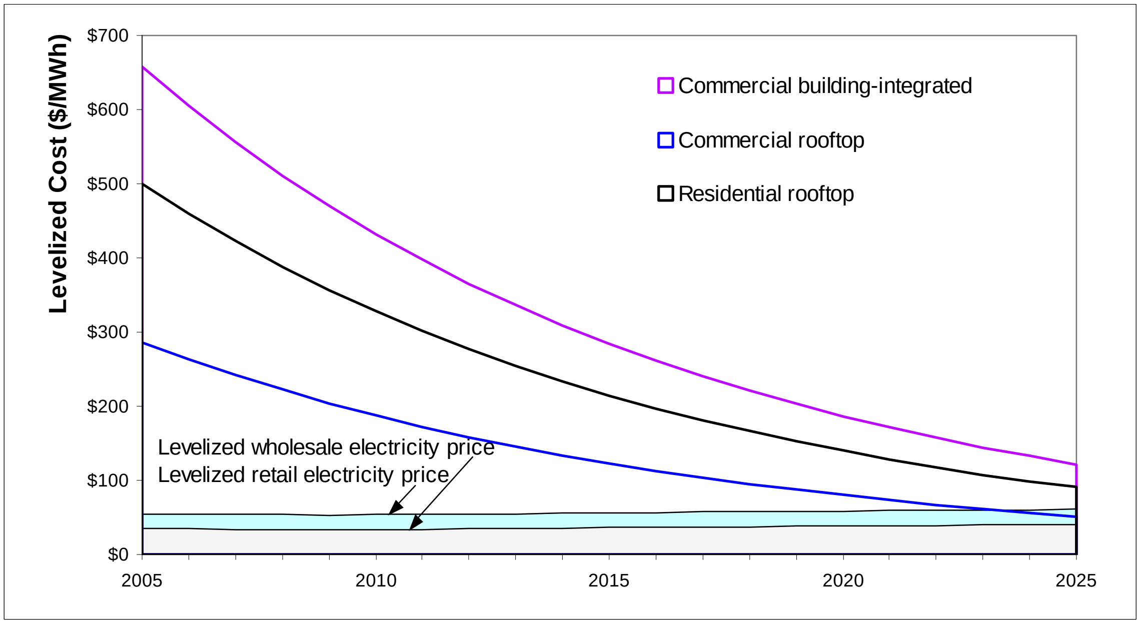


Figure J-8: Forecast levelized electricity cost for solar photovoltaic systems

High initial cost and electric power production costs much greater than alternatives has limited the development of photovoltaic systems. The situation is especially challenging in the Northwest because of poor solar resource in populated areas and the absence of seasonal coincidence between the solar resource and winter-peaking electrical loads. However, financial incentives, such as those provided by the Oregon Energy Trust and Oregon state business tax credits, coupled with the popular appeal of solar photovoltaic power is resulting in an increasing number of residential and commercial installations. Several of the latter range to hundreds of kilowatts capacity.[88]

Photovoltaics is a commercially mature technology in some respects, with a limited market because of extremely high cost, but with substantial potential for cost reduction over the term of this plan. Though not suitable for capacity backup or for cogeneration (concentrating systems excepted), photovoltaic installations are widespread, expanding, and cost-effective for low power consumption applications remote from grid service ("remote" in a cost-of-service sense. Some applications are only feet from grid distribution lines.). Grid-connected installations are on the rise among those willing to pay a premium for the low environmental impact and cachet of

[87] Benchmark power cost assumptions: Levelized lifecycle cost, 2010 service, uniform financing (20% publicly-owned utility, 40 percent investor-owned), 30-year system life. Production tax credit and renewable energy (green tag) credit set at the annual means of the portfolio analysis. Residential system is assumed to be net-metered (no capacity cost); $2/kW/yr capacity cost assumed for commercial systems.
[88] Renewables Northwest Project maintains and inventory of regional solar photovoltaic installations at www.rnp.org.

photovoltaics. Though prices have not significantly declined in recent years, the nature of solar photovoltaics suggests that there is potential for significant reduction in cost and for some improvement in performance. It appears possible that the cost of electricity from unsubsidized small-scale photovoltaic installations could be competitive with retail electricity prices by the end of the planning period.

Small wind turbine-generators

Small wind turbine-generators (to 100 kW rated capacity) are an established, commercial technology. Small wind turbine-generators were first marketed in the early decades of the 20th century to provide electricity at rural sites not served by electric utilities. The technology has improved greatly since the late 1970s with new materials and better engineering, though reliability issues remain. Three-blade, horizontal axis designs using direct-drive DC generators are typical. Inverters are used for interconnected with the grid or when serving AC loads. A 10 kW turbine might have a 22-foot diameter rotor assembly and be mounted on a guyed tower ranging to about 100 in height.

Applications for small wind turbines include remote residential, telecom and water pumping loads, and village power systems in remote locations or in areas of developing countries without reliable grid service. Though the cost of small-scale wind turbines precludes widespread use where reliable grid service is available, grid-connected installations are occasionally found, especially where renewable energy development incentives are available. The American Wind Energy Association estimates that about 15 MW of small wind turbine capacity is currently installed in the United States.

The installed cost of a typical 5 to 15kW grid-connected wind turbine generating system in 2002 was reported to be about $3500/kW. These machines will operate at a capacity factor of about 14 percent in a USDOE Class 2 wind resource area, producing 1200 kWh per kilowatt of capacity per year. Equipment design life ranges from 20 to 30 years. Industry goals are to reduce installed costs by 5 percent per year and to increase system productivity by about 2 percent per year, on average, while improving reliability, life expectancy, noise levels and reducing inspection and maintenance requirements.[89] Limited available information suggests operation and maintenance costs range from 2 to 4 % of capital costs per year. The resulting benchmark power cost is about $200 MWh.[90] The effect of goal technology cost and productivity improvements on the cost-effectiveness of small wind turbine systems is shown in Figure J-9.

[89] American Wind Energy Association. The US Small Wind Turbine Industry Roadmap. June 2002.
[90] Benchmark power cost assumptions: Levelized lifecycle cost, 2010 service, uniform financing (20% publicly-owned utility, 40 percent investor-owned), 25-year system life. Production tax credit and renewable energy (green tag) credit set at the annual means of the portfolio analysis. Residential system is assumed to be net-metered (no capacity cost).

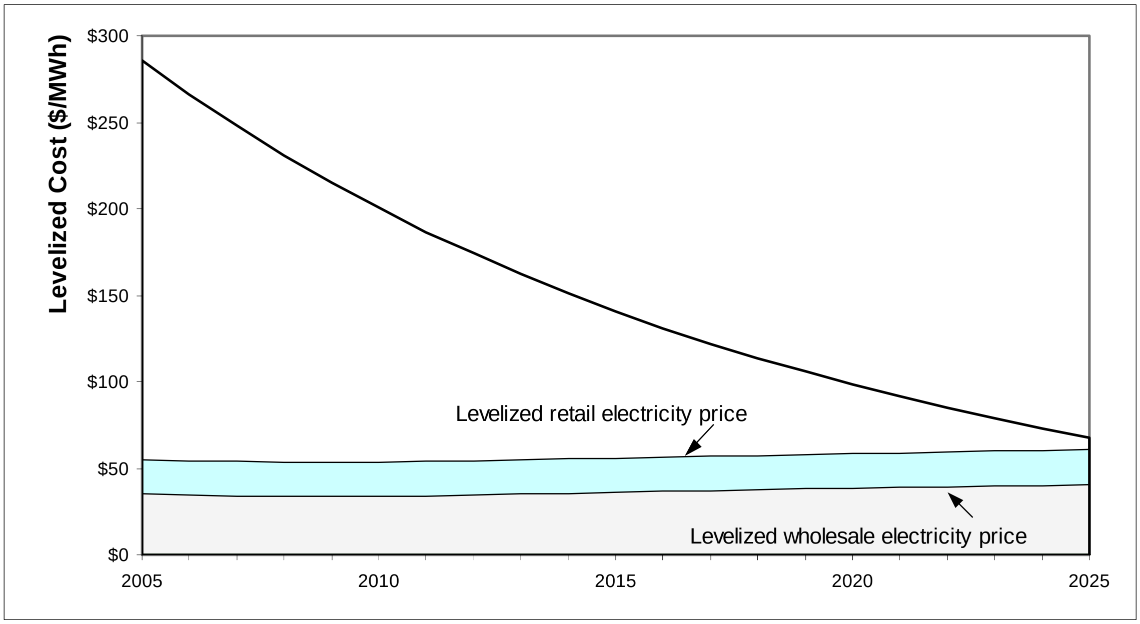


Figure J-9: Forecast levelized electricity cost for small wind turbine systems