NATIONAL REGULATORY
RESEARCH INSTITUTE

1080 Carmack Road
Columbus, Ohio 43210

Phone: 614-292-9404
Fax: 614-292-7196
www.nrri.ohio-state.edu

What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria

Joe McGarvey, Research Associate
Ken Costello, Senior Institute Economist
R. Scott Potter, Senior Research Associate
Michael Murphy, Graduate Research Associate
Paul Laurent, Graduate Research Associate

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Executive Summary

As load grows and old plants retire, the public will need new sources of electricity generation. State public utility commissioners will have obligations and opportunities to influence, and in some cases determine, the mix of generation technology and fuels for their states.

Understanding the nature and major characteristics of individual generation technologies is a first step in determining the appropriate mix of technologies. This report develops nine criteria key to that understanding; then applies those criteria to each of 14 technologies. The technologies and criteria are listed in the tables below.

A second step in determining the appropriate mix involves evaluating the "fit" of each technology in the context of an existing power system, consisting of generation facilities and customers with specific demand characteristics. The report examines the role that portfolio analysis can play in that evaluation. The report concludes by exploring what information decision-makers need to conduct their evaluations.

The appendices offer diagrams of each of the 14 technologies, along with tables detailing the current mix of generation in each state.

Types of generation technologies

Fossil-fueled
- Combined cycle gas turbines
- Combustion gas turbines
- Pulverized coal generation
- Fluidized bed combustion
- Integrated gasification combined cycle (IGCC)

Nuclear

Wind

Pumped-storage hydropower

Miscellaneous
- Photovoltaic power
- Concentrated solar power
- Biomass power
- Geothermal power
- Barrage and ocean current generation
- Fuel cells

Criteria for describing generation technologies

- Load-service function
- Time to construct
- Cost to construct
- Operational life
- Fuel costs
- Fuel dependability
- Plant dependability
- Maturity of the technology
- Externalities

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I. Introduction: Why care about generation mix?

State public utility commissions (PUCs) face decisions about the appropriate mix of generation technologies and fuels. These decisions will affect the public, the environment, the economy, and the owners of the technologies for thirty or more years. Cost is only one consideration. State regulators also must ensure reliability and service quality, all consistent with the state's environmental and economic development priorities.

Additional generation is only one part of the equation. Commissions should consider energy efficiency and demand-side management programs that lower the total level or alter the daily patterns of customer demand for electricity. But new sources of generation will be part of the solution to meeting future demand. This report focuses on generation.

Each technology has its proponents. Many of those proponents will assert that their technology serves the public interest. The commission's responsibility is to provide its judgment of what mix of technology best serves the public interest. This report provides some tools necessary to reaching that judgment, by comparing each technology across nine characteristics. **Part II** of the report describes those characteristics. **Part III** then discusses each of 14 technologies in terms of those characteristics. The technologies and criteria used to describe them are listed below.

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Understanding the major characteristics of individual generation technologies is a first step in evaluating generation. A second step involves evaluating each of the technologies in the context of a power system comprised of existing generation facilities and customers with specific demand characteristics. **Part IV** examines the role that portfolio analysis can play as a conceptual framework for state commissions to apply to information on individual generation technologies in order to make socially desirable decisions. **Part V** concludes the report by exploring what information decision-makers need to have when evaluating generation technologies.

The report now examines three reasons why the generation mix in their state should be important to state regulators: (1) the commission's regulatory obligations; (2) the presence of uncertainty in the regulatory process; and (3) federal statutory requirements.

A. Generation mix decisions arise in all states regardless of the status of retail competition

Concerns about generation mix fall within the core of state commissions' regulatory obligations. This proposition is true for all states, whether their market structure is the traditional regulated monopoly structure or one allowing for retail competition.

In states which have not authorized retail competition, there are monopoly providers of bundled retail electric service subject to rate-of-return and quality of service regulation.[1] Commissions in these states make multiple decisions that influence the mix of generation in the state:

1. Cost recovery proceedings require commissions to set the rates for power produced from current plants and set the terms and conditions for utility service.

2. Certification proceedings require commissions to evaluate a utility's resource adequacy in light of its obligation to serve the public.

3. Generation siting proceedings require commissions to examine the environmental and other locational effects of proposed plants, sometimes in the form of an environmental impact statement; transmission siting proceedings also influence the amount and type of generation since the lines are necessary to carry the power.[2]

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[1] Bundled electric service is the offering of combined generation supply, transmission, and distribution service by one company. A company offering bundled service may own its own generation, acquire its generation from third parties, or both.

[2] Siting and plant certification processes overlap in some states.

4. Some states set generation reserve margins deemed necessary to ensure that sufficient power is available to provide service and maintain the proper functioning of the transmission grid.

5. Traditionally regulated and, less often, retail competition states can also influence the generation mix though a state-wide or regional planning process. Integrated resource planning (IRP) processes are not used by commissions in all states; when used, they require utilities to evaluate different options for meeting and shaping projected future demand for electricity, with the goal of determining the best combination of demand-side and supply-side resources.

6. Renewable portfolio standards are laws that require retail electric suppliers to procure a given percentage of their power from renewable sources by a given target date. PUCs typically are responsible for implementing and enforcing these requirements. Appendix A lists the 23 states that currently have renewable portfolio standards in place.[3]

Commissions in states authorizing competition for retail sales of electricity have more circumscribed authority over power producers than in traditionally regulated states. Commission authority in restructured states typically centers on: (1) siting of new plants (where that authority existed previously); (2) overseeing statutory portfolio standards that apply to competitive retailers; (3) approving the procurement decisions of incumbent utilities acting as default service providers as mentioned above, and (4) overseeing public benefit programs for energy efficiency and renewable energy, in states where such programs exist.

Even in these retail competition states, there usually remains a legislated commitment to provide "default" or “standard" service to non-shopping customers. In these states, the majority of residential customers depend for this essential service on the default provider, which is usually the incumbent utility. These states still have an interest in attaining the proper mix of generation used for default service. And, provided these states' statutes continue to grant the commission jurisdiction over quality of service, rates, and infrastructure planning relating to default service, the state commissions still have responsibility to influence a utility's choice of generation.

B. Generation mix decisions address multiple uncertainties

A regulator’s consideration of generation mix must take into account at least five sources of uncertainty:

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[3] For a detailed discussion of renewable portfolio standards, see Scott Hempling and Nancy Rader, *The Renewables Portfolio Standard: A Practical Guide*, National Association of Regulatory Utility Commissioners, February 2001. Document available at: www.naruc.affiniscape.com/associations/1773/files/rps.pdf.

1. **Market conditions:** Uncertainties exist in load growth (i.e., the change in the total amount of demand for electricity)), load shape,[4] and market prices for power.

2. **Fuel prices**: Fuel prices fluctuate according to the supply and demand of the marketplace. Natural gas is a recent example. The increase in construction of natural gas plants started in the early 1990s, during which decade the plants compromised approximately 90 percent of new electricity generating capacity. Additions to gas generating capacity slowed after 2000 in part as a result of the high and volatile natural gas prices from 2000 to the present. The U.S. Department of Energy (DOE) Energy Information Administration (EIA) forecasts that the share of planned additional generation using natural gas will fall from 73.1 percent in 2006 to 37.6 percent in 2010.[5]

3. **National policies:** Legal actions at the national level, in the form of legislation or regulatory orders, inject additional uncertainty. National renewable portfolio standards and regulation of carbon dioxide to curb global warming, for example, are two policies that would affect generation comparisons. In addition to possible action on greenhouse gas emissions

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[4] Load shape refers to the shape of the curve on a two-dimensional axis, in which the Y-axis displays demand, the X-axis displays the time of occurrence of that demand, and the values reflect the customer (or customer group's) load at each point in time. A city's load shape for a 24-hour period in August would show low levels from midnight until about 6am, with load then growing to a peak by late afternoon, then gradually falling into the evening. A manufacturing firm with constant demand throughout the day would have a load shape consisting of a horizontal line intersecting the Y-axis at that demand level.

[5] Untied States Department of Energy, Energy Information Administration (hereafter cited as EIA), *Electric Power Annual 2005,* DOE/EIA-0348(2005), November 2006, Table 2.4. Document available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

As another indication of how changing natural gas prices alter forecasting and planning, EIA's predictions for the share of electricity generated in the U.S. from natural gas in 2020 fell from 31 percent to 21 percent in its forecasts released in 1999 and 2006. See EIA, *Annual Energy Outlook 2000*, DOE/EIA-0383, Table A8, December 1999, and EIA, *Annual Energy Outlook 2007 (Early Release)*, December 2006, Table A8. Natural gas represents 1,476 billion kilowatthours (kWh) out of a total 4,757 billion kWh of electricity generation projected for 2020 in *AEO 2000* compared to 1,060 billion kWh of natural gas-fired generation out of a total 5,037 billion kWh for the same year in *AEO 2007*.

by the 110th Congress, the Supreme Court is considering a case that addresses whether the federal government must regulate carbon dioxide under the Clean Air Act.

4. **Fuel supply:** Some fuels are more vulnerable than others to interruptions. The 1973 OPEC oil embargo is a prominent example. Other vulnerabilities include railroad lines essential to a utility's coal deliveries. natural gas pipeline ruptures, and a drought of wind or water affecting wind turbines or hydro-electric dams.

5. **Commission forecasting processes:** Forecasts are uncertain by definition. To increase accuracy, commissions and their regulated utilities revisit their forecasts periodically, within integrated resource planning or forecasting proceedings. Unforeseen events still occur, including technological change, construction delays, and cost overruns.

C. The Energy Policy Act of 2005 requires states to consider diversity in generation fuels and technologies

State commissions have a third reason to consider generation mix: Congress ordered them to do so. The Energy Policy Act of 2005 (EPAct 2005), in an amendment of the Public Utility Regulatory Policies Act of 1978 (PURPA), requires state commissions to consider whether it is appropriate to implement standards requiring each jurisdictional electric utility to: (1) develop a plan "to minimize its dependence on one fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies;" and (2) "develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation."[6]

EPAct 2005 leaves implementation of the fuel sources and fossil fuel generation efficiency standards to state commissions. The commissions will have to begin considering the standards for their jurisdictional utilities by August 8, 2007, making determinations by August 8, 2008.

Another influence on each state's generation mix is the 2005 amendments to Section 210 of PURPA. That section, enacted in 1978, required each utility to buy capacity and energy from "qualifying facilities" (defined to include cogenerators and small renewable power producers), at a price equal to the utility's "avoided cost" (the cost the utility would have incurred if it had procured the needed capacity and energy from other sources (or self-supplied)). The U.S. Supreme Court has described the 1989 Congress's two-fold intent: to reduce the demand for fossil fuels and to overcome

[6] PURPA Sec. 111(d)(12) and Sec. 111(d)(13), as added by Sec 1251(a) of EPAct 2005.

utilities' "reluctan[ce] to purchase power from, and to sell power to, the nontraditional facilities."[7]

Section 1253(a) of EPAct 2005 created multiple paths by which a utility may obtain from FERC an exemption from this purchase obligation. Common to these paths is a FERC finding that QFs who otherwise would seek to sell to the utility have access to buyers in competitive wholesale markets. Elimination of the mandatory purchase obligation in a market is likely to change the mix of generators selling into that market.

D. Structure of the remainder of this report

Part II of this report begins by describes nine criteria for evaluating different types of generation technologies. **Part III** describes the 14 generation technologies most likely to attract state interest; the descriptions apply Part II's nine criteria. **Part IV** introduces a conceptual framework, portfolio analysis, for commissions to apply to the information on individual generation technologies when determining the appropriate generation mix. **Part V** recommends steps for commissions to take in preparing for generation mix decisions.

The report includes three appendices: (1) a table listing states with renewable portfolio standards, including target years and target levels for generation from renewable resources; (2) diagrams illustrating the basic components of the 14 generation technologies; and (3) a state-by-state list of the current generation mix in each state, organized by the technologies and fuels used for the generation and listing the average age of the plants.

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[7] *FERC v. Mississippi*, 456 U.S. 742, 750 (1982); *American Paper Institute, Inc. v. American Elec. Power Serv. Corp.*, 461 U.S. 402, 405 (1983)

II. Nine criteria for comparison: What characteristics should regulators examine when evaluating generation technologies?

The following are the criteria that this report identifies as being useful for evaluating generation technologies:

- Load-service function
- Time to construct
- Cost to construct
- Operational life
- Fuel costs
- Fuel dependability
- Plant dependability
- Maturity of the technology
- Externalities

A. Load-service function

The attractiveness of a particular generation option depends on the role it will play in meeting load. Does the service territory need baseload, intermediate or peaking generation? What types of generators serve which of these functions? This subsection explains these concepts.

The demand for power – sometimes termed the "load" – varies every minute as residents and businesses make individual decisions to turn their appliances and machines on or off. Since utilities and customers cannot normally store electricity,[8] these load variations must be matched by generators, instantaneously and exactly, to keep power flowing and to keep the electric interconnected system (generation, transmission and distribution) stable. Along with the minute-by-minute variations are larger scale variations – intra-day (compare 2 pm with 2 am), intra-week (compare Monday with Sunday) and seasonal (compare August with April).

Load service function refers to the role that generators play in meeting these variations in load. Different types of generators vary in their cost of operation and time required to respond to load changes. Rather than run all plants at all times (an economically inefficient practice), in any particular hour the power system operator chooses that mix of generators that minimizes cost, subject to environmental constraints.[9]

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[8] Storage is possible in the context of pumped hydro plants. See Part III.D below.

[9] Given the dynamic nature of demand for electricity, regions of the country each maintain a margin of available generating capacity beyond the likely demand in order to provide the power necessary to maintain the stability of the power system. With the use of capacity margins, it is rarely necessary to use all available generation capacity for a given time of the day or year.

Key terms

Efficiency (or thermal efficiency): the extent to which a power plant is able to convert the energy content of fuel into electricity.

Heat rate: a measure of the thermal efficiency of a power plant.[10] The measure is expressed in British thermal units per net kilowatt-hour of electricity. The lower the plant's heat rate, the higher the plant's efficiency, because it requires fewer units of fuel input to produce a kwh of electricity.

Power supply planners normally classify generating units into one of three categories according to their operational role:

1. **Baseload plants** are run at all times, except during repairs or scheduled maintenance. These plants have low variable operating cost relative to other plants. Baseload plants are typically nuclear, coal-fired, or hydropower units. In combination, baseload plants provide the minimum level of power that is always required by customers. Because they run continuously, they provide the majority of the electric energy used. When demand rises above baseload levels, (e.g., a weekday afternoon), the operator brings other plants on line. The hours or days of "ramp up" time for typical baseload plants (i.e., the time it takes to "get them up and running" to deliver power) is longer than the time necessary for the other types of plants.

2. **Peaking plants** are dispatched to meet high demands, like air conditioning loads on weekday afternoons. Peaking plants range in operation from several hours a day to only a few hours a year. Failing to meet peak demand would lead to curtailment of customer service or, in the extreme, a system-wide blackout. Given that it is usually more expensive to build a highly efficient plant, peakers tend to be built with lower efficiency than base load plants since they are used for fewer hours. Peakers must be able to start up and deliver power on very short notice from the power system operator. Peaker plants are frequently simple cycle gas turbines burning natural gas, with diesel oil serving as a backup fuel, or compression ignition reciprocating engines burning diesel oil.

3. **Intermediate or "shoulder" plants** fall in between baseload and peaking plants in terms of their hours of usage and efficiency. The plants are used in combination with baseload plants to meet all but the highest demands for electricity; that is, they are not run all the time, but they come on line as load grows. Newly built intermediate plants are usually high-efficiency gas turbines. Sometimes operators do use natural gas- and

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[10] See Joel B. Klein, "The Use of Heat Rates in Production Cost Modeling; and Market Modeling," Staff Report, Electricity Analysis Office, California Energy Commission, April 17, 1998. Document is available at: http://www.energy.ca.gov/papers/98-04-07_heatrate.pdf.

coal-fired plants for intermediate load. Many intermediate plants are former baseload plants, no longer cost-effective for the baseload role.

Key terms

Capacity factor: The ratio of (a) the net amount of electricity a plant actually generates in a given time period to (b) the amount that the plant could have produced if it had operated continuously at full power operation during the same period.[11] Capacity factor is dependent on both the mechanical availability of the plant and the economic desirability to run the plant given the particular cost to run it.

Availability factor: The ratio of (a) the number of hours a generating unit is mechanically able to produce power in a given period to (b) the number of hours in the period.[12] A factor less than 100% indicates planned or unplanned outages for maintenance. A plant's availability factor will be higher than its capacity factor, because a plant is not used in every hour it is available.

Load factor: The ratio of the average load to peak load served by a plant or power system during a specified time interval. A higher load factor indicates higher use of the generating resources. This report does not use this factor as a variable for comparing technologies because it is specific to a particular plant and power system rather than being a general characteristic of a given technology. We include the term here to distinguish it from capacity and availability factors.[13]

A prospective owner of a plant will determine in advance of construction whether the plant is likely to serve as a baseload, intermediate, or peaking facility. This determination includes forecasts for a plant's average level of output and its annual production of electricity, which can be expressed as the plants load and capacity factors. Both of these factors affect the technical and economic choices that an owner makes when designing a plant.[14] The actual economic performance of a plant is dependent upon how often the power system operator calls upon the plant to send power onto the grid.

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[11] See EIA *Glossary*.

[12] See EIA, *Renewable Energy Annual Glossary*. Glossary is available at http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/gl.html.

[13] Ibid.

[14] For example, an owner will likely design an intended peaking plant to be able start-up quickly but will not spend as much to engineer a highly fuel efficient since it will be operated infrequently compared to a base load plant.

Power system dispatchers (also known as "operators") manage the flow of electricity from generation plants over the transmission and distribution lines to the end customer. Depending on the region of the country, dispatchers work for a single utility, an independent system operator (ISO), or a regional transmission organization (RTO). It is the power system dispatcher's job to ensure that, within his physical area of responsibility, the amount of generation necessary to meet fluctuating load is available, either from generation located in that area or imported from outside the area. Dispatchers choose which generation units will supply power at a particular time. Dispatching is often conducted automatically using computers. The dispatcher's choice of plants is faces at least two limitations. One is the level of congestion in the transmission system at different locations; for example, the operator cannot dispatch a plant if the transmission system is congested at the location where that plant would inject its power. Imagine a police dispatcher needing to dispatch a police cruiser to an emergency. If the one cruiser is located at a congested intersection, the dispatcher will send the other. A second limitation is the plant's operating characteristics. A plant's variable operating cost (i.e., the cost of producing an additional watt of power) and its ramp-up time affect how often power system operators will dispatch it.[15]

Each hour, system operators choose plants based on the principles of economic dispatch. Economic dispatch refers to "operating a coordinated system so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls)."[16] Of two comparable plants (e.g., with comparable heat rates and ramp-up times), one natural gas-fired and the other coal-fired, the coal plant with the lower variable cost (e.g., due to a lower cost of fuel), would be dispatched before the gas-fired plant during normal operation of a power system, all else equal. Among two plants using the same fuel, the one with the higher efficiency and, hence, lower variable operating cost, would be dispatched first. In addition, plants with engineering characteristics that increase their ramp-up time must be dispatched a few or many hours prior to the anticipated need.

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[15] Ramp-up time refers to the time it takes for a plant to become operational. Some plants can become operational within minutes or even seconds; others take several hours to move from cold status to operating status. As an analogy, compare a car waiting with its engine running to a car that has been sitting in the cold for a month.

[16] U.S. Department of Energy (hereafter cited as DOE), "The Value of Economic Dispatch: A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005," November 7, 2005, p. 9. Document is available at: http://www.oe.energy.gov/DocumentsandMedia/value.pdf.

B. Time to construct

Regulators must be aware of the lead time necessary to allow for the construction of new generation that will be necessary to meet future demand. In this document, "time to construct" is the estimated length of time necessary to construct the plant, excluding any pre-construction regulatory processes. The time to construct begins with the first day of construction and concludes with the first day the unit would be capable of generation if fuel was present.

Construction time also affects the capital requirement of a project because a long time horizon for construction raises the cost of financing the plant. The costs are higher because (a) the generation owner is paying interest on construction loans during the construction process, and (b) lenders tend to charge higher interest on loans associated with long construction periods due to the risk of delays and non-payments.

C. Cost to construct

Building and operating a power plant involves multiple categories of costs: fuel cost, operation and maintenance costs, overnight construction cost, and interest expense.[17] The two largest costs of a power plant are the overnight construction cost and the fuel cost. This report presents approximate values for both categories. The overnight construction cost and fuel cost are not project-specific, meaning that the reader can compare these costs across types of generation.

This report presents, for each technology, the overnight cost, consisting of all material and labor of the main contractor, plus the cost of associated sub-contractors, but excluding interest expenses.[18] We report the cost to construct in dollars per kilowatt

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[17] The following equations show the relationship between cost terms referenced in this report:

Capital cost	= overnight construction cost + interest expenses
Operating cost	= cost of fuel + fixed operation and maintenance + variable operation and maintenance
Variable cost	= variable operation and maintenance + cost of fuel
Total cost	= capital cost + operating cost
Levelized cost	= total cost per MWh, spread out equally over the life of the plant

[18] For estimates of O&M costs, see EIA, *Assumptions Used in the Annual Energy Outlook, 2006*, DOE/EIA-0554(2006), March 2006, Table 38, p. 73. Document is available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2006).pdf.

($/kW) of generation using constant 2006 dollars.[19] The term is known as "overnight cost" since it describes what the plant cost would be if it were built and paid for overnight, requiring no time-dependent expenses. The measure does not reflect the total construction cost of a plant since it excludes the interest expenses of financing a specific project. The longer the length of time needed for construction, the greater the difference between the true cost to construct and the overnight cost to construct.[20] To avoid any bias toward projects with long construction periods, a regulator must account for interest expense to arrive at the total construction cost. The figures cited in this report are representative numbers only. Given the dynamic nature of capital costs, regulators evaluating a given project should obtain data that is recent and specific to that project.

Interest rates will vary by the project and by the creditworthiness of the company proposing to build the plant. Another variable affecting fully capitalized cost to construct (i.e., overnight cost plus interest expenses) is each state's policy on the recovery of construction costs during the construction period. Some states prohibit recovery of construction costs until the plant commences operation. Other states allow recovery in the rate base of construction work in progress (CWIP). In the latter states, total construction costs for the owner will be lower since interest expenses will accumulate over a shorter period of time. The cost to consumers from a CWIP allowance depends upon whether the economic return that the consumers forego by paying for the plant before it is completed is greater than the benefit of paying lower interest costs for the plant in the rate base.

Construction costs for a project depend on many factors that vary over time or are specific to the project, including the prices of critical commodities (e.g., concrete and steel), waste disposal fees, and availability of transportation to the site. A second unit on an existing site will usually have lower costs than the first plant; a larger plant will tend to have a lower construction cost per kilowatt of capacity compared to a smaller plant due to economies of scale. State-specific environmental regulations can also require the use of more emissions control equipment, affecting the capacity and efficiency of the unit, and therefore its cost.

This report does not include costs for land, operation and maintenance (O&M), emission allowances, or transmission interconnection costs since their high variability by plant makes comparisons difficult at a generalized level across different types of generation technologies.

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[19] The authors converted nominal prices to 2006 dollars using the U.S. Department of Commerce, Bureau of Economic Analysis' GDPDEF index, the GDP implicit price deflator, available at http://research.stlouisfed.org/fred2/series/GDPDEF?&cid=18.

[20] See John M. Marshall and Peter Navarro, "Costs of Nuclear Plant Construction: theory and new evidence," *RAND Journal of Economics*, Vol. 22, No. 1, (Spring) 1991.

D. Operational life

Operational life is the amount of time that a plant is mechanically able to provide service, inclusive of any refurbishment or re-licensing. A plant typically requires more maintenance and experiences more forced outages as it ages, resulting in a lower availability factor. For each technology, the report presents the typical operational life of a plant. In addition, Appendix E presents the average age of generation units currently in service, grouped by state and type of technology, to provide a point of reference for considering the expected lifespan of plants.

Operational life is a physical concept (i.e., how long with the plant live?); it differs from book life, which is an accounting concept. (i.e., over what period of time should the owner recover its costs?).

E. Fuel costs

A generation technology that is not cost competitive at one point in time improves its competitiveness if the price for fuel used by that technology declines relative to other technologies using other fuels.[21]

This report first presents the cost of fuel in dollars per million British thermal units ($/MMBtu). This presentation facilitates comparison across fuel sources; e.g., does it cost more to get a unit of energy from coal or gas? The cost of purchasing fuel is only one variable in the calculation of a plant's total fuel cost. Total cost for a specific generation unit depends also on the unit's heat rate. The higher the heat rate, the more units of fuel is necessary to produce a given amount of energy; thus the higher the heat rate, the lower the plant's efficiency. For a particular generator, therefore, the total cost of fuel per kWh generated generation equals the product of the plant's heat rate and the price of the fuel.[22] To approximate each technology's fuel cost per kWh of output, this report uses heat rates that EIA has found typical of new units of a given type of technology.[23]

Generation technologies differ in the degree that fuel plays in its total operating cost. For example, approximately 75% of the production cost of electricity for a natural

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[21] Relative cost of fuel is only one factor that can affect the relative economic merit of technologies. Emission-control policies are an example of another factor.

[22] For a generation plant that uses fuel with a price of "*x*" dollars per million Btu and the plant burns the fuel with a heat rate of "*y*" Btu per kWh, the plant's price of fuel per kWh of electricity output would equal [$*x*/MMBtu] · [(*y*Btu($10^{-6}$))/kWh].

[23] EIA, *Assumptions Used in the Annual Energy Outlook, 2006*, Table 38.

gas combined-cycle plant is due to fuel cost, compared to 30% for a typical coal-fired plant.[24]

Key terms

British thermal unit (Btu): The amount of energy required to raise one pound of water by one degree Fahrenheit, if the water is at its highest density at about 39 degrees Fahrenheit.

Kilowatt-hour (kWh): The amount of energy produced when 1,000 watts of electrical power is expended for one hour. An average U.S. household uses about 11,000 kWh of electricity in a year.

Capacity: The maximum output that generating equipment can supply to the power system under ambient conditions, expressed in Megawatts (MW). The actual capacity of a given plant will usually be less than its installed capacity.

Installed capacity (or nameplate capacity): The maximum output of a generator under controlled conditions specified by the manufacturer, expressed in MW.[25]

F. Fuel dependability

A generator can operate only if the required fuel is available. The report describes fuel dependability for each generation type, highlighting strengths and vulnerabilities.

The presence of fuel transportation networks affects the suitability of a particular generation technology for a particular locale. Power plants sited near existing fuel supply networks are more economical, all else equal. Competition for a given fuel from other sectors of the economy can reduce the supply of that fuel available for generation. Natural gas, for example, also serves as a heating fuel and a feedstock for chemical manufacturing.

To avoid depending on a single fuel type, some plants (primarily natural gas units) have the capability to burn multiple fuels.[26] An ability to use multiple fuels is

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[24] George Booras and Neville Holt, "Pulverized Coal and IGCC Cost and Performance Estimates," presented at Gasification Technologies 2004 in Washington, D.C., October 3-6, 2004.

[25] Unless otherwise noted, these definitions are adapted from the EIA *Glossary*.

valuable where: (1) it is expensive to store one of the fuels (e.g., natural gas); (2) the delivery infrastructure lacks redundancy; or (3) capacity margins (i.e., the surplus of capacity over peak load, necessary to ensure continued operation if one or more generators or transmission lines go out of service or load grows beyond expectations) are low.

G. Plant dependability

The report uses a generation technology's availability factor as its measure of the dependability of the plant. Availability factor is the percentage of hours in a given period that a plant is physically available to produce power. The availability factor measures whether a plant is able to produce power, not whether it actually produces power. (The measure for actual production relative to total hours is the capacity factor; see section II.A for a full definition.) The availability factor is always higher than the capacity factor for a given plant. The more hours in a year that a plant is out of service (e.g., for scheduled or unscheduled maintenance), the lower is its availability factor.

Low dependability causes several costs. First, unplanned outages harm a plant owner's revenue stream. Second, shutdowns require utilities and other service providers with sales obligations to customers to pay penalties for contract breach, or purchase higher cost power in the spot market. Third, unplanned outages in one generator can strain other components of the interconnected system, if capacity margins are inadequate.

H. Maturity of the technology

Maturity of the technology refers to the degree to which a given technology is proven commercially. The criterion measures whether the generation type is:

(1) In development: One of the first examples of the technology, yet to be installed or installed in a very few locations for testing purposes, with insufficient long-term data to make reliable and detailed analysis possible.

(2) Newly operational: Few installations, with insufficient long-term data to make reliable and detailed analysis possible;

(3) Mature: Many installations, with sufficient data to make reliable and detailed analysis possible; or

(4) Fully mature: Many installations, some past or nearing operational life expectancy, with sufficient data to make reliable analysis possible; possibly no longer an efficient or appropriate technology.

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[26] Multi-fuel capability is a consideration primarily for natural gas-fired plants to enable the use of both natural gas and distillate fuel. Coal-fired plants are also sometimes designed to burn biomass at the same time (i.e., co-fire) or can be switched to operate fully on gas liquid fuels.

The measure of maturity is subjective. This report describes the generally accepted industry view on each generation type, based on the authors' examination of technical analyses. Maturity matters, because a proven technology offers less risk to investors and more certainty to regulators. As new technologies gain a market beachhead and begin commercial operation, engineers gather operational data useful in lowering cost and improving performance.

I. Externalities

An externality exists when costs (or benefits) associated with a commercial transaction are borne (or enjoyed) by a non-party to that transaction.[27] If a person plants flowers in his or her open yard, there is a positive externality benefiting neighbors and passersby, free of charge. If a new power plant built for (and paid for) by a specified customer group provides electric power to that group, but also improves reliability of the regional transmission grid, the region's non-paying residents receive a positive externality. And if these same non-paying customers also breathe in the pollutants from the plant, yet receive no compensation for their suffering, they incur a negative externality.[28] In each case, non-parties to the transaction receive benefits or incur costs. Other examples of negative externalities include the vistas lost due to wind farm installation in a scenic area, reduced public enjoyment of rivers that are dammed for a hydropower project, or the reduction in property values arising from proximity to a large plant causing traffic, pollution, or risk of explosion.

In each example, the total cost to society of a power plant is not captured in the dollar cost that is paid by the owner to build and operate the plant. Therefore, more power would be produced by the plant, or at a lower price, or with fewer pollution controls than what would be optimal if everyone's full costs and benefits were taken into account. Neither the economic marketplace, nor the courts, nor regulatory agencies are able to evaluate all societal costs of a given power plant. Regulatory statutes usually command regulators to use their best judgment of what serves the public interest when they evaluate the sources of power; these statutes differ in terms of what elements of the public interest must receive consideration. This report highlights the most prominent environmental, social, or security externalities for each type of generation technology.

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[27] See James M. Buchanan and William C. Stubblebine, "Externality," *Economica*, Vol. 29, November 1962, pp. 371-84; and Ronald M. Coase, "The Problem of Social Costs," *Journal of Law and Economics*, Vol. 3, October 1960, pp. 1-44.

[28] Emission taxes and trading plans (also known as "cap-and-trade"), such as the programs created under Title IV of the 1990 Clean Air Act or the U.S. Environmental Protection Agency's Clean Air Interstrate Rules (CAIR) and Clean Air Mercury Rules (CAMR) of 2005, are efforts to attach a monetary cost to emissions and assign that expense to the transacting parties so that the emissions are no longer fully external costs.

III. Fourteen generation technologies: What are their characteristics?

This section describes fourteen generation technologies in terms of the nine criteria for comparison described in the previous section. The report covers the first eight technologies in more detail because they are likely to constitute the bulk of new generation coming before commissions and more information is available about them. The fourteen generation technologies that the report covers are:

1. Combined cycle gas turbines
2. Combustion gas turbines
3. Pulverized coal generation
4. Fluidized bed combustion
5. Integrated gasification combined cycle (IGCC) generation
6. Nuclear generation
7. Wind generation
8. Pumped-storage hydropower
9. Photovoltaic
10. Concentrated solar power
11. Biomass power
12. Geothermal power
13. Barrage and ocean current generation
14. Fuel cells

Of the fourteen technologies, twelve of them rely on a generator that uses mechanical energy to move an electrically conductive material through a magnetic field. The movement through that field, under the laws of electromagnetism, translates the mechanical energy into electrical energy. Whether the source of mechanical motion is (a) blowing wind, (b) steam created by the burning of fossil fuels or a nuclear reaction, or (c) the rush of water across a dam, most generators operate by spinning the blades of a turbine to create motion within a magnetic field.

Certain other technologies rely on different processes, such as the effect of light energy falling on photovoltaic materials or the conversion of chemical potential energy to electricity in a fuel cell. The specific operation of alternative power plants will be described in more detail in the technology-specific sections below. Appendix D presents diagrams of each technology. Table 1, immediately below, presents a summary of the report's information about the generation technologies.

Table 1: Summary of generation technologies (continued on next page)

	Load service function	**Time to construct**	**Cost to construct** (Overnight cost: 2006$/kW)		**Operating life**	**Fuel cost** (2006 $/MWh)	**Fuel depend-ability**	**Plant depend-ability** (availability factor)	**Maturity**	**Externality: CO_2 emissions**[2] (metric tons per MWh by 2010-2015) [Source: EPRI[1]]
			Source: EIA, others	Source: EPRI[1]						
Combined cycle	Baseload, Intermediate Peak	3-5 years	$565-$620	$500	25-30 years	$50.37	Medium	90%	Mature	.39
Combustion gas	Peak	Less than 1 year	$411-$431	Not available	25-30 years	$75.60	Medium	95%	Mature	Not available
Pulverized coal	Baseload	3-4 years	$1,235	$1,350 ($2,270 with CO_2 capture)[3]	30-50 years	$14.02	High	72-90%	Mature	.80 for supercritical plant without C02 capture (.052 with capture)
Fluidized bed	Baseload	3-4 years	$1,327	$1,480	30 years	$15.08	High	90%	In development	.87
IGCC	Baseload	3-4 years	$1,431	$1,490 ($1,920 with CO_2 capture)[3]	Not available	$13.17	High	88%	Newly operational	.86 without capture .156 with capture
Nuclear	Baseload	9 years	$1,849	$1,510-$1840	40-60 years	$4.89	Medium	90-97%	Mature	None
Wind	Intermediate	3 years	$1,157	$1,190	20 years	$0	Low	98%	Mature	None
Pumped-storage hydro	Peak	4-5 years	$2,379	Not available	50-60 years	Existent cost of electricity	High	90-95%	Mature	Not applicable

Table 1: Summary of generation technologies (continued from previous page)

	Load service function	Time to construct	Cost to construct (Overnight cost: 2006$/kW)		Operating life	Fuel cost (2006 $/MWh)	Fuel depend-ability	Plant depend-ability (availability factor)	Maturity	Externality: CO2 emissions[2] (metric tons per MWh by 2010-2015) [Source: EPRI[1]]
			Source: EIA, others	Source: EPRI[1]						
Photovoltaic	Intermediate Peak	2 years	$4,222	Not available	20-40 years	$0	Low	99%	Mature	None
Concentrated solar	Intermediate	3 years	$2,745	$3,410	30 years	$0	Low	Not available	Mature	None
Biomass	Baseload	4 years	$1,759	$2,160	Not available	$1.55-$49.19	High	90%	Mature	.10
Geothermal	Baseload	4 years	$2,227 binary	$2,270 binary; $1,400 flash	30 years	$0	High	92%	Mature	None
Barrage and Ocean current	Intermediate	Not available	Not available	Not available	Not available	$0	High	Not available	In development	None
Fuel cells	Baseload, Intermediate Peak	3 years	$4,015	$1,620 - $2,160 (by 2020)	Not available	Not available	Not available	Not available	In development	Not available

Notes on Table 1:

1. Comparison data on overnight cost to construct are courtesy of EPRI, from their 2006 presentation, "Generation Options Under a Carbon-Constrained Future." Costs are reported in 2006 dollars, but represent EPRI's outlook for 2010-2015. All fossil units assume 600 MW capacities. NGCC unit based on GE7F machine or equivalent. Binary geothermal unit includes reservoir development and associated cost of fuel supply; flash unit assumes re-injection of fluid in closed loop operation. Biomass CO_2 emissions assumes 90% of emissions are absorbed by biomass crop growth cycle.

2. See Appendix B for a discussion of CO_2 capture and storage and data on its effects on the cost to produce electricity.

3. EPRI's cost for CO_2 capture cost does not include the cost of CO_2 storage.

A. Fossil-fueled generation technologies

1. Combined cycle gas turbines

Overview: Since the early 1990s, gas-fired power plants have comprised over 90 percent of new generation capacity in the United States. Several reasons account for this happening, including new federal environmental regulations and the low price of natural gas that prevailed until 2000. Even with the continuation of high natural gas prices, EIA projections call for future construction of gas-fired facilities. Factors explaining the attractiveness of gas-fired plants include their low environmental effects relative to other fossil fuel plants, their modularity (i.e., the capability of gas-fired plants to alter their capacity over time at low cost in response to changed economic conditions), and low capital costs compared to most other generation technologies.[29] During 2005, the net generation of electricity from all gas-fired facilities approximated the generation from nuclear power plants.[30]

Gas-fired generating technologies include electric steam plants, combined cycle gas turbines (CCGTs), combustion gas turbine generators (CGTs), reciprocating engine generators, each covered in this report. CCGTs and CGTs are the gas-fired technologies under closest review in planning by electric utilities and non-utility generators. During the past fifteen years, CCGTs in particular have displaced old steam gas facilities with much lower energy efficiencies.

CCGTs use both gas and steam-turbine thermodynamic cycles to generate electricity. A CCGT uses the waste heat from the gas turbine to produce steam that, in turn, generates additional electricity by turning the blades within a steam turbine. Combining two cycles in the generation of electricity improves overall heating efficiency (i.e., the ratio of energy input to kW-hours of generated electricity) by as much as 50 percent over the heating efficiency of combustion gas turbines. The capacity of a new CCGT plant (employing two gas turbines and 1 steam turbine) is typically in the range of 500-600MW.[31] Section III.E of this report discusses integrated gasification combined-

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[29] See EIA, *Annual Energy Outlook 2006*, p. 85. In its long-term projections, the EIA projects 130 GW of new gas-fired capacity between 2005 and 2030, which represents about 85 percent of new coal-fired capacity for the same period.

[30] Ibid. Nuclear and gas-fired plants each produced about 19 percent of the total net electricity generation in 2005.

[31] For an overview of the CCGT technology, see Northwest Power Planning Council (hereafter cited as NPPC), "Natural Gas Combined-Cycle Gas Turbine Power Plants," internal paper, August 8, 2002. Report is available at: http://www.westgov.org/wieb/electric/Transmission%20Protocol/SSG-WI/pnw_5pp_02.pdf.

cycle (IGCC) power plants that fire the finished synthetic gas in a natural gas combined-cycle power plant

Load-service function: Most new gas-fired generating facilities built since the early 1990s are CCGTs. These facilities can provide baseload, intermediate or peak load services, or a combination of them. How much baseload electricity a CCGT provides depends largely on the price of natural gas, as the utilization of this technology depends upon its position in the dispatch order and, thus, its operating cost. Compared with other baseload technologies, CCGTs have high variable costs (mainly fuel costs) that cause their capacity factors to fluctuate more widely from period to period because of economic dispatch rules.

For new plants, some studies estimated the capacity factor for new CCGTs to average between 80-90 percent.[32] Over the past few years, CCGTs have operated at much lower levels – on the order of 30-40 percent – because of natural gas prices rising above the $6-$7 per thousand cubic feet (Mcf) range. An 80-90 percent capacity factor assumes a drop in natural gas prices from current levels (about $6 per Mcf at the time of this writing) that would allow a CCGT to operate mostly to serve baseload.

Time to construct: The typical construction time for a CCGT is approximately two years, as compared to the 3-5 year range for other baseload generating facilities like coal-fired and nuclear power.[33]

Cost to construct: The overnight construction costs of new CCGTs range from $565-$620 per kW.[34]

Operational life: The service life of CCGT is in the range of 25-30 years.[35]

Fuel costs: Fuel costs represent about 75 percent of the total cost (i.e., the sum of operating and capital costs) of CCGTs. In recent years with the high price of natural gas (gas prices this century are about three times their average level in the 1990s), CCGTs have operated less as other facilities with lower running costs, especially coal-fired plants, have replaced them in the dispatching order. Assuming that the price of natural

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[32] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, prepared for Docket 02-IEP-01, June 5, 2003, C-2; and Northwest Power and Conservation Council (hereafter cited as NPCC), *The Fifth Northwest Electric Power and Conservation Plan*, May 2005, p. I-29, report available at: http://www.nwcouncil.org/energy/powerplan/plan/Default.htm.

[33] Ibid.

[34] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38, p. 73.

[35] Ibid.

gas equals $7 per Mcf and the heat rate for a CCGT is 7,196 Btu per kWh, the running cost of the CCGT (excluding other variable costs) would be about $0.05 per kWh, or $50.37 per Megawatt-hour (MWh).[36] This figure compares unfavorably with the running cost of other baseload plants. EPRI studies have shown that when gas prices exceed $6 per Mcf, new CCGTs lose their competitiveness with other technologies, particularly pulverized coal plants.[37] The volatility of gas prices has also made CCGTs less economically attractive. During the years 1997-2005, the average price of natural gas to power generators fluctuated between $2.40 per Mcf and $8.45 per Mcf, with pronounced volatility beginning this century.[38] To reduce the adverse consequences of gas-price volatility on cash flow and profits, some generators have locked in gas prices through contracting or hedging.

Fuel dependability: Fuel dependability has emerged as a problem for some CCGTs, notably for units located in pipeline-constrained areas such as New England and Florida. In New England, for example, most gas-fired generators find it uneconomical to have firm contracts with pipelines, making the generators vulnerable to the risk of unavailable pipeline capacity during extreme winter peak periods.

Dependability of the plant: CCGTs have high availability factors, with new facilities having a combined scheduled and forced outage rate of less than ten percent.[39] Their dependability has made them profitable when dispatched as baseload power in organized wholesale electricity markets.

Maturity of the technology: CCGTs represent a mature technology that has been in place for almost twenty years and that has experienced minimal operational problems in electricity-generation and other industrial applications. Heat rates for new CCGT facilities are likely to continue to improve in the future.

Externalities: CCGTs emit fewer air pollutants relative to other fossil-fuel facilities. CCGTs emit about half the CO_2 per MWh of a pulverized coal plant: 0.4 tons per MWh versus 0.8 tons per MWh.[40] If the federal government or individual states

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[36] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38, p. 73.

[37] See Steve Specker, Electric Power Research Institute (hereafter cited as EPRI) "Generation Technologies in a Carbon-Constrained World," presented at RFF Policy Leadership Forum, Washington D.C., March 30, 2006. See also EPRI, "Generation Technologies for a Carbon-Constrained World," *EPRI Journal*, Summer 2006, pp. 22-39.

[38] See EIA, "Natural Gas Navigator," software program available at: tonto.eia.doe.gov/dnav/ng/hist/n3045us3a.htm.

[39] See NPPC, "Natural Gas Combined-Cycle Gas Turbine Power Plants."

[40] See Steve Specker, EPRI, "Generation Technologies in a Carbon-Constrained World"; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, p. I-34.

implement carbon-constraining regulations, the economic affect will be the highest on coal-facilities, with a lesser effect on CCGTs, and the least effect on renewable-energy and nuclear technologies.

CCGTs occupy about one-tenth the space of nuclear and a pulverized super-critical coal plants. This fact partially explains the low level of public opposition to CCGTs relative to other baseload technologies. Nevertheless, some local concerns have occurred, especially in the western states, over water consumption by a CCGT.[41] One source states that a 500 MW CCGT using the most common cooling method (i.e., recirculating wet-cooling) would use 2.1-2.6 million gallons of water per day.[42] While not a direct effect of a CCGT plant, the process of exploring, drilling, storing and transporting natural gas imposes land-use, ecological and aesthetic problems.

The siting and building of CCGTs have confronted little public opposition with the exception of some facilities contested for their consumption of water for plant condenser cooling. In the future, dry (or closed-cycle) cooling can help to reduce water consumption, although it has the potential to increase cost and reduce efficiency.

2. Combustion gas turbines

Overview: A combustion gas turbine, also known as a simple cycle gas turbine, is a rotary engine that compresses gas and air, combusts the mixture, and extracts energy by allowing the combusted gas to expand through rotating turbine blades. This technology finds use in transportation engines and heavy-duty industrial machines. Some CGTs are based on turbines designed for aircraft and are often referred to as "aero" or "aero-derivative" designs. The installed capacity of CGTs for electric generation ranges from less than one MW to approximately 200 MW, with smaller plants tending to provide localized distributed generation.[43]

Load-service function: CGTs operate mainly as peaking facilities. They can provide emergency and other ancillary services in addition to back-up power for wind and hydroelectric facilities. In the Pacific Northwest, for example, CGTs operate to back up the non-firm (i.e., not guaranteed for delivery) output of hydroelectric plants, especially during years with low rainfall and water levels.[44] CGTs are especially valuable in meeting peak demands for electricity because of their ability to provide

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[41] See NPPC, "Natural Gas Combined-Cycle Gas Turbine Power Plants."

[42] John S. Maulbetsch and Michael N. DiFillipino, "Cost and Value of Water Use at Combined-cycle Power Plants," April 2006, prepared for the California Energy Commission, CEC-500-2006-034, p. 7.

[43] Ibid.

[44] Ibid., pp. I-20 and I-21.

needed power within minutes. CGTs have a high ramp rate (i.e., the rate of change of plant output), so they are able to operate at full capacity in under an hour after a start-up notice, much more quickly than the hours or days needed for some coal and nuclear plants. Mainly serving peak demands, CGTs typically have a capacity factor in the range of 10-15 percent.

Time to construct: The construction period for CGTs varies from several weeks to as much as one year for larger facilities.

Cost to construct: In case of CGTs with an installed capacity of over 100 MW, estimates of overnight construction costs are in the \$411-\$431 per kW range.[45] Overnight costs per kW for smaller CGTs can rise to much higher levels as a consequence of economies of scale in construction.

Operational life: Service lives for CGTs range from 25 to 30 years depending in part on their load factors.

Fuel costs: Volatile natural gas prices impose a risk on CGTs generators and their customers. Compared to a CCGT, the levelized cost (i.e., the combined operating and capital costs per MWh, spread out equally over the life of the plant) of a 100-MW CGT plant operating at a ten percent capacity factor is approximately three times higher.[46] The higher cost for CGTs is largely the result of a higher heat rate and lower capacity utilization. The much higher levelized cost for CGTs does not detract from their potential economic value in meeting peak demand and in providing ancillary services. Higher gas prices also have a greater effect on the operating costs of CGTs compared with CCGTs because of their higher heat rates (approximately 40 percent higher, in the range of 9,500-10,000 Btu per kWh generated compared to a heat rate of 6,700-7,200 Btu per kWh for a CCGT). As an illustration, for every dollar increase in the price of natural gas, the cost of power from a CGT, assuming a heat rate of 10,842 Btu per kWh, would rise by \$0.01 per kWh, or \$10.80 per MWh; for a CCGT with a heat rate of 7,196 Btu per kWh, the cost of power would increase by a lesser \$0.007 per kWh, or \$7.19 per MWh.

Fuel dependability: As with CCGTs, dependability of natural gas supply delivery poses a challenge for CGTs because of potential localized pipeline bottlenecks, especially in New England and Florida.

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[45] See EIA, *Assumptions for the Annual Energy Outlook 2006*, p. 85.

[46] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, p.3

Dependability of the plant: CGTs are highly reliable, with availability factors of around 95 percent.[47] Similar to other gas-fired technologies, CGTs face the risk of the unavailability of delivered gas when needed, especially if the operator has non-firm pipeline capacity leading to potential shortfalls during "bottleneck" episodes.

Maturity of the technology: CGTs are a mature technology with a record of reliable performance over the last four decades.

Externalities: Due to their higher heat rates compared with CCGTs, CGTs emit more nitrogen oxide and carbon dioxide into the air per unit of electricity generated. For example, CGTs produce over 40 percent more CO_2 per kWh generated than CCGTs.[48] CGTs are smaller than the other power plants using fossil fuels, so their footprint on the local environment is less visible. Similar to CCGTs, natural gas drilling, storage, and transportation have a negative effect on land use, ecological conditions, and aesthetics. The footprint of a facility is more evident when it includes fuel oil storage and back-up capability for switching between gas and oil.

3. Pulverized coal generation

Overview: Currently, pulverized coal (PC) generation plants are the largest segment of the nation's generation fuel-mix, accounting for approximately 50% of the nation's energy. According to a report by the U.S. Department of Energy's National Energy Technology Laboratory (NETL), more than 50% of the planned new generation capacity plant additions through the year 2030 are likely to be coal-fired.[49]

In a PC generation facility the coal is *pulverized* (or ground) into a fine powder, mixed with air, and then blown – like a gas – into a boiler furnace. In the furnace, the PC-air mixture burns in a controlled manner somewhat similar to natural gas. However, the PC-air mixture is not as uniform as natural gas and, therefore, requires a more sophisticated combustion control process. The heat generated by the burning PC-air mixture is used to generate steam. The steam is used to drive the generator turbines which ultimately produce the electricity. The actual design of a PC generation plant varies according to the type and quality of coal, and the intended operating steam pressure and temperature.

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47 See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, p. D-1; and NPCC *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-4.

48 See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. I-27 and I-34.

49 See DOE, National Energy Technology Laboratory (hereafter cited as NETL), *Tracking New Coal-Fired Power Plants – Coal's Resurgence in Electric Power Generation,* September 29, 2006.

Coal is typically divided into four major types with differing carbon and moisture contents. Generally, the coal with the highest carbon and lowest moisture contents has the highest heat value and is the cleanest to burn. In order of most to least carbon content, the four types (or ranks) of coal are anthracite, bituminous coal, subbituminous coal, and lignite.

Anthracite or "hard coal" generally has a carbon content between 86-95 percent, a heat value between 22 and 28 MMBtu per ton, and a moisture content of less than 15 percent. Anthracite is high in carbon, low in sulfur, very black and shiny.

Bituminous coal is the most abundant coal in the United States. It is softer than anthracite and has a carbon content between 45 – 86 percent, a heat value of between 21 and 30 MMBtu/ton, and a moisture content of 20 percent or less. It is often noted by having both shiny and matte portions.

Subbituminous coal is also called black lignite. It has a carbon content of 35-45 percent, a heat value between 17 and 18 MMBtu/ton, a moisture content of 20-30 percent, and it features a matte surface. Subbituminous coal is used for generating electricity and space heating.

Lignite or "brown coal" is, geologically speaking, the youngest type of coal. It has a carbon content of 25-35 percent, a heat value between 9 and 17 MMBtu/ton, and a moisture content up to 45 percent. Lignite is brown to black in color, has a matte surface, and tends to crumble (like soil).[50]

Plants designed to burn coal with higher moisture, sulfur, and/or ash contents require more internal boiler area for heat transfer than a PC plant designed to burn only low sulfur, low moisture, high-carbon coals.

The steam systems used in the current generation of PC plants are generally classified as subcritical (or conventional), supercritical, or ultra-supercritical.[51] The classification is based on the operating steam pressure and temperature. The exact specifications for the classification vary within the worldwide power generation industry. In the United States subcritical plants operate at a pressure of 2400 pounds per square

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[50] See EIA, *Glossary*.

[51] The critical point of water is the pressure and temperature points at which water ceases to be a liquid. Supercritical steam is a steam which is under pressure above its critical temperatures. Under supercritical conditions the water is technically neither a gas or a liquid, but a fluid with a unique combination of the properties of gas and liquid. A supercritical fluid can diffuse through solids and dissolve substances.

The term "advanced supercritical" is sometimes used instead of "ultra-supercritical."

inch (psi) and a maximum temperature of 1050°F. A supercritical unit would have similar temperatures but pressures of 3500 psi or more. Ultra-supercritical units are variably defined, but commonly would have operating pressures of 4500 psi and temperatures of 1100°F or higher.

As the temperature and pressure of the steam at the generator turbine inlet increases, so does the efficiency of the power steam cycle. As the efficiency of the steam cycle is increased, the amount of fuel necessary to produce the same amount of energy is reduced, thereby reducing plant emissions.

The decision to build either a subcritical or supercritical PC plant depends on several factors including, but not limited to, the cost of coal, environment requirements, capital costs of constructions, and intended load use. For example, high fuel costs and high environmental requirement costs can make the higher operating efficiency of a supercritical plant sufficient to offset (or surpass) the higher capital cost of construction.

Load-service function: PC-fired generation units are almost always operated for baseload capacity. Subcritical PC units can also be used for load-following or cycling service as the subcritical units can generally operate with better efficiency at reduced output levels than similarly sized supercritical units.

Currently operating PC plants have capacities ranging from 100 MW to 1300 MW. The average nameplate capacity of a PC generation unit installed in the United State in the in the past 20 years is just over 300 MW.[52]

Time to construct: EIA data, actual utility construction records, and utilities estimates show a range from 36-48 months for construction of a new PC power plant, assuming no construction delays.

Cost to construct: An average cost to construct is approximately $1235/kW. [53] EIA forecasts that the cost in 2010 will be $1,308/kW and by 2020 it will be $1,271/kW.[54] The advanced materials and systems necessary for a supercritical plant make the cost to construct generally higher than that of a similarly sized subcritical unit.

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[52] See EIA, "Existing Generating Units in the United States, 2004," *Form EIA-860 Database*. Database available at: http://www.eia.doe.gov/cneaf/electricity/page/capacity/existingunits2004.xls. Estimate is derived from EIA data; the estimate considers utility generators that use only coal for the fuel source.

[53] See EIA, *Electric Power Annual, 2005*. The average is calculated from a review data from EIA's *Annual Energy Outlook 2006* and a number of specific utility construction estimates.

[54] See EIA, *Assumptions to the Annual Energy Outlook 2006,* release, Table 48, p. 85.

Operational life: Allowing for upgrades and partial replacement, as of 2005 there were more than 500 currently operating coal-fired utility generation units that had been in operation for more than 30 years. As of 2005, there were 346 coal-fired units in service in the U.S. that had been in operation for over 50 years.[55]

Fuel costs: The sulfur content of coal affects its price since higher sulfur coal requires correspondingly higher costs for the purchase of state or federally-mandated allowances for the emission of sulfur dioxide (SO2). The proximity of the plant to the type of coal required is a key factor in the cost of fuel since transporting coal over long distances is expensive. The 2005 national average raw fuel cost for PC-fired generation was $1.54/MMBtu (in 2005 dollars), a 13.2% increase over 2004.[56] Assuming a heat exchange rate of 8,844 Btu/kWh, the cost of fuel per kWh of generation is $0.014, or $14.02/MWh (in 2006 dollars).[57]

Some portion of the increase in coal prices in 2005 was likely attributable to a extraordinary number of specific events that affected the 2005 coal production cycle.[58] The average 2001-2004 annual increase in coal prices was just over 3%. Prices declined annually between 1994 and 2000.

It is likely that coal prices will continue to increase. The demand for coal continues to increase as worldwide utilization increases. In the United States alone there are, at least, 50 new coal-fired generators planned additions in the next four years.[59]

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[55] Data are from EIA, "Annual Electric Generator Report, 2005," *Form EIA-860 Database*, released October 2006. Database available at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html. Data represents all operating, grid-connected plants using coal as their primary fuel source that were built in 1956 or earlier. See Appendix E for additional information on plant ages.

[56] See EIA, *Annual Energy Outlook 2006, Revised Report November 9, 2006,* Table 4.5 "Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1994 through 2005;" and EIA, "Coal Production in the United States – An Historical Overview, October 2006."

[57] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

[58] Included in these events, among others, were three major hurricanes, other regional flooding, and low levels on some waterways that disrupted supply transportation routes.

[59] See DOE, NETL, *Tracking New Coal-Fired Power Plants – Coal's Resurgence in Electric Power Generation,* September 29, 2006.

Fuel dependability: The dependability of the coal supply appears favorable. According to EIA's *Annual Energy Outlook 2006*, coal production "remained near 1,100 million tons annually since 1996" and will increase steadily through 2030.[60] Mining production in the United States and worldwide continues to increase.[61]

Dependability of the plant: The average capacity factor for coal power plants in the United States in 2005 was 72 percent.[62] The availability factor for both subcritical and supercritical PC power plants is between 80-90%.[63] Supercritical plants generally have a higher availability factor than the subcritical plants.

Maturity of the technology: Coal-fired power plants use mature technology. As previously mentioned, 346 plants operating in 2005 were installed more than 50 years ago.[64] Even supercritical PC plant designs are highly proven technology with installations dating back to 1957.[65]

The ultra-supercritical plants are not yet common, but are growing in numbers. China recently launched that nation's first ultra-supercritical plant.[66] In August 2006, AEP announced a proposed 600 MW ultra-supercritical plant to be built near Texarkana, Arkansas.[67]

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[60] See EIA, *Annual Energy Outlook 2006 with Projections to 2030,* February 2006, p.98.

[61] Ibid.

[62] Howard Gruenspecht, Deputy Administrator Energy Information Administration, U.S. Department of Energy, statement before the U.S. Senate Committee on Energy and Natural Resources, U.S. Senate, May 25, 2006.

[63] Estimates derived from an examination of multiple utility reports of projections and/or actual availability factors. See Tennessee Valley Authority (hereafter TVA), *Power Facts*, document available at http://www.tva.com/power/powerfacts.htm; and Associated Electric Cooperative Inc., *2005 Annual Report,* p. 3.

[64] See EIA, "Existing Generating Units in the United States by State, Company and Plant 2004," *Annual Electric Generator Report, 2005: Form EIA-860 Database*. Data available at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

[65] Philo Unit 6 in Ohio operated from 1957 to 1975.

[66] Huaneng Yuhuan Power Plant in China's Zhejiang Province announced the launch of the first 1000MW unit of a multi-unit ultra-supercritical generation facility.

[67] See American Electric Power (AEP), press release, August 9, 2006, "SWEPCO announces Hempstead County as site for new base load generation power plant."

Externalities: The combustion of coal creates several byproducts damaging to the environment, including SO_2, nitrogen oxides (NO_x), carbon dioxide (CO_2), mercury and other trace metals, ash, and volatile organic compounds (VOC). These atmospheric emissions and other waste products are factors in the actual PC plant design and the associated type of coal used as fuel. In the United States, to meet federal Clean Air Act requirements many of the PC plants originally designed to burn higher sulfur coals have been converted to enable the burning of lower sulfur coals. These environmental retrofits have high capital costs, and they can also reduce the available capacity of the plants.[68] However, according to an August 2006 report from EPRI, recent improvements in post-combustion CO_2 capture technology can make a supercritical PC plant burning bituminous or sub-bituminous coal and using post-combustion CO_2 capture "competitive with IGCC using pre-combustion capture."[69] Historically, much of the environmental concern was directed at CO_2, NO_x, and SO_2. Increasing concerns about the harmful health and environmental effects of mercury and ash are present in the public debate over coal-fired power plants.

Water use is another potential negative environmental externality for PC plants. A supercritical PC plant uses an average of 1042 gallons of water per MWh of generation.[70] While much of the water is ultimately returned to the source, the temperature and purity of the wastewater are issues. Some of the wastewater being returned to the source may contain trace-levels of metals (including arsenic, copper, mercury, and selenium), ammonia, and other chemicals.[71] The wastewater may be at a higher temperature than the source water into which it is mixing. Wastewater pollutants and thermal effects can have an impact the quality of the source water and on the aquatic plant and animals of the source water. The construction of a new PC plant, whether subcritical or supercritical, is likely to face community opposition. A PC power plant, the transmission switching stations, power lines, associated facilities and other appurtenances and can occupy 500 acres or more. The perceptions of aesthetic and environmental impacts are typically the most significant topics of opposition. The

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[68] Systems such as flue gas desulphurization (FGD) and selective catalytic reduction (SCR) require power to operate and therefore draw power ("auxiliary power") from the generation unit. In combination the two systems may reduce available capacity by 4%.

[69] John Wheeldon, George Booras, and Neville Holt, *Post-Combustion CO_2 Capture from Pulverized Coal Plants*, Electric Power Research Institute, Palo Alto, California, August 2006.

[70] See NETL, *Power Plant Water Usage and Loss Study*, August 2005.

[71] NETL, Office of Fossil Energy, *Program Facts*, "Innovative Approaches and Technologies for Improved Power Plant Water Management", January 2004.

system of coal delivery (rail or barges) also raises noise concerns if the facility is within earshot of a residential area.

4. Fluidized bed combustion

Overview: Fluidized beds suspend solid fuels on upward blowing jets of air during the combustion process. This process results in a mix of gas and solids. This mix, which resembles a turbulent fluid, provides for efficient chemical reactions and heat transfer. Emissions of SO_x and NO_x are reduced by limiting combustion temperature to between 800-900º C and by injecting a sorbent material (e.g., crushed limestone or dolomite) into the combustion chamber.[72]

There are two types of fluidized bed combustion technology: atmospheric fluidized bed and pressurized fluidized bed. Atmospheric fluidized bed systems combust fuel under atmospheric pressure. In pressurized fluidized bed systems, the reactor vessel is pressurized to produce sufficient flue gas energy to drive a gas turbine in conjunction with a steam turbine in a combined cycle.

Fluidized bed combustion combines fuel flexibility and low emissions relative to pulverized coal plants. Almost any combustible material, from coal to municipal waste, can by burned. Fluidized bed combustion plants can meet SOx and NOx emission standards without the need for scrubbers or other external emission controls. Boiler manufacturers are currently offering fluidized bed boilers as a standard package.[73]

Load-service function: Fluidized bed combustion technology is suitable for baseload operation because it combines low cost fuels and high output. Babcock and Wilcox states that its second generation Ebensburg Plant had an average availability factor of 90% over a 13-year period, and that its third generation Southern Illinois University Plant averages 93% availability.[74] DOE's JEA Large Scale CFB Combustion

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[72] DOE, *Fluidized Bed Technology Overview*. Document available at: http://www.netl.doe.gov/technologies/coalpower/Combustion/FBC/fbc-overview.html.

[73] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June24, 2005. Report available at: http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/jacks/Final_Technical_Report_Compendium.pdf

[74] M. Maryamchik and D.L. Wietzke, *B&W IR-CFB Operating Experience and New Development*, Babcock and Wilcox technical paper, presented to the 18th International Conference on Fluidized Bed Combustion May 22 - 25, 2005, Toronto, Ontario, Canada. Document available at: http://www.babcock.com/pgg/tt/pdf/BR-1765.pdf

Demonstration Project plant in Florida operated for 6,843 hours in 2003 and 5,450 hours in 2004.[75] The capacity range of installed units is from 80-460 MW.[76]

Time to construct: Construction times for fluidized bed combustion systems are similar to those of pulverized coal plants, ranging from 36-48 months.

Cost to construct: The approximate cost of an atmospheric fluidized bed combustor is $1,327/kW, or 5-10% more than a pulverized coal boiler without SO_2 scrubbers or selective catalytic NO_x reduction equipment.[77] With SO_2 scrubbers or selective catalytic NO_x reduction equipment installed, however, a pulverized coal boiler is 8-15% more expensive than a fluidized bed combustion boiler.[78] A cost estimate performed on Japan's 360-MWe pressurized fluidized bed combustion Karita Plant projected a capital cost of $1,536.[79]

Operational life: Fluidized bed combustion is a new technology and no firm estimates of operational life are available. The U.S. Environmental Protection Agency estimated a 30-year operational life for DOE's JEA Project in Florida.[80]

Fuel costs: A wide range of combustible materials can be used as fuel for a fluidized bed combustion boiler. The JEA demonstration plant in Florida has tested various coals, high sulfur petroleum coke, and coal-coke blends. The plant reported an

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[75] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

[76] The 460 MW unit is a Foster Wheeler supercritical boiler in Poland. Foster Wheeler has plans for units up to 600 MW. See Goidich *et al., Design Aspects of the Ultra-Supercritical CFB Boiler*, presented at the International Pittsburgh Coal Conference, Pittsburgh, PA, September 12-15, 2005.

[77] The cost to construct is calculated from a review of data from EIA's Annual Energy Outlook 2006, a number of specific utility construction estimates, and from Kavidass, S., *et al.*, *Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power*, Babcock & Wilcox Company, September 2000.

[78] Ibid.

[79] See NETL, *Project Fact Sheet: CCPI/Clean Coal Demonstrations: Tidd PFBC Demonstration*. The cost to construct the plant was $1,263/kW in 1997 U.S. dollars. Document available at: http://www.netl.doe.gov/technologies/coalpower/cctc/summaries/tidd/tidddemo.html.

[80] Record of Decision, JEA Circulating Fluidized Bed Combustor Project, Federal Register: December 7, 2000 (Vol.65, Num. 236). Document available at: http://www.epa.gov/fedrgstr/EPA-IMPACT/2000/December/Day-07/i31160.htm.

average heat rate of 9,516 Btu/kWh for 2003-2004. Using the same cost of coal reported in section III.C of this report (i.e., $1.54/MMBtu), the cost of fuel per kWh of generation at the JEA demonstration plant is $0.015, or $15.08/MWh (in 2006$).[81] For additional information on the costs of coal, please refer back to this report's examination of pulverized coal plants in section III.C. Fluidized bed combustion units can also use other fuels including biomass and sewage sludge.

Fuel dependability: Due to the range of fuels that fluidized bed combustion plants are able to use, the fuel supply is dependable.

Dependability of the plant: The large scale demonstration plant sponsored by DOE encountered boiler problems that led to forced outages, yet still had an availability of 75%.[82] As noted above, commercial manufacturers state availability factors of 90-93%.

Maturity of the technology: The technology is new and immature.

Externalities: The land requirements for fluidized bed combustion plants are the same as conventional coal fired plants. The combustion of coal creates several byproducts damaging to the environment, including SO_2, NO_x, CO_2, trace metals, ash, and some volatile organic compounds (VOC). Fluidized bed combustion plants can meet current SOx and NOx emission standards without any added emissions control devices. Researchers are currently investigating capturing CO_2 during the combustion process.[83] The DOE has begun selling bed ash and fly ash as industrial byproducts for fill material from the JEA Plant.[84]

5. Integrated gasification combined cycle (IGCC) generation

Overview: Integrated Gasification Combined Cycle (IGCC) generation is a combination of two technologies: coal gasification and combined cycle. Gasification

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[81] NETL, "JEA Large-Scale CFB Combustion Demonstration Project CCTDP." Document available at: http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/jacks/documents/jacks.pdf.

[82] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

[83] See Abandes *et al.*, "Fluidized Bed Combustion Systems Integrating CO_2 Capture with CaO," *Environmental Science and Technology,* Vol. 39, No. 8 (March 2005), pp. 2861-2866,.

[84] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

uses steam and oxygen to convert fuel into synthesis gas (syngas). Syngas is a mixture of carbon monoxide, carbon dioxide, and hydrogen created by the gasification process. IGCC plants can be powered by many carbon-based fuels, such as coal, petroleum coke, and biomass. The syngas contains two primary combustible components: hydrogen and carbon monoxide. The syngas is fired in a gas turbine. The hot exhaust gas from the turbine is routed to a heat recovery steam generator, where it produces steam to power a steam turbine. Electricity is produced by both cycles (the gas turbine and the steam turbine), thus the term combined cycle.

The syngas also contains carbon dioxide. Because carbon dioxide and other unwanted emission-forming constituents can be removed from the syngas and separated before combustion, IGCC plants could rival the low emissions of natural gas fired plants even when using coal as a fuel. If the gasifier is fed with oxygen rather than air, tle flue gas contains highly-concentrated CO_2 which can be captured at a lower cost than from conventional coal or gas-fired plants.[85]

Load-service function: IGCC plants are suitable for baseload operation because they combine low cost fuels and high output. The DOE-assisted demonstration plants have not achieved plant availabilities over 80%, although availability would be higher if a spare gasifier was employed. American Electric Power (AEP) predicts 85% availability for its IGCC plants.[86] The capacity of existing and planned units typically ranges from 250-630 MW. Tampa Electric's Polk County plant is 618 MW.[87] The Wabash River plant is 296 MW.[88] AEP plans to begin construction on a 600 MW unit in 2007.[89] Some companies considering IGCC plants are planning facilities that would provide from 540 to 1,100 MW of capacity.[90]

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[85] See Appendix B of this report for data from the Intergovernmental Panel on Climate Change (IPCC); see also the EPRI/CURC *Technology Roadmap*, available at http://www.coal.org/content/roadmap.htm.

[86] American Electric Power, presentation at "Wall Street Utility Group Meeting," September 21, 2006, New York City, available at: http://www.aep.com/investors/present/documents/AEPPresentationForWSUGMeeting9-21-2006.pdf.

[87] DOE, *Final Technical Report for the JEA Large-Scale CFB Combustion Demonstration Project*, June 24, 2005.

[88] Ibid.

[89] AEP, "Wall Street Utility Group Meeting," September 21, 2006, New York City.

[90] Robert Charles, e*t al.*, *Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016*, report prepared by

Time to construct: An IGCC plant requires 36 to 48 months to construct.[91] This time does not include planning and permitting.

Cost to construct: A 600 MW IGCC plant costs approximately $1,431/kW to construct.[92] Equipment to capture and sequester carbon dioxide would increase this cost to $1986/kW.[93] The gasification process facilitates carbon dioxide capture. Factoring in the possible future benefits of reduced carbon emissions lowers the net costs of IGCC.[94]

Operational life: IGCC is a new technology and no firm estimates of plant life are available.

Fuel costs: IGCC technology can use a range of fuels. The power plant portion of IGCC comprises the gas turbine combined cycle technology capable of operating on natural gas or distillate oil. The gasifier is also able to gasify most types of coal and other carbon based fuels such as biomass. IGCC technology is suitable for low grade fuel, though existing plants use bituminous coal or petroleum coke. Using the same cost of coal reported in section III.C of $1.54/MMBtu, and assuming a heat exchange rate of 9,713 Btu/kWh for IGCC with carbon capture, the cost of fuel per kWh of generation is about $0.015, or $15.39/MWh. Assuming a heat exchange rate of 8,309 Btu/kWh for IGCC without carbon capture, the cost of fuel per kWh of generation is about $0.013, or $13.17/MWh.[95] For additional information on the costs of coal, please refer back to this report's examination of pulverized coal plants in section III.C.

Fuel dependability: Due to the range of fuels that may be employed with IGCC, the fuel supply is dependable.

Dependability of the plant: Today IGCC plants have availability factors of 88% for single gasifier units. IGCC units with spare gasifiers have higher availability factors.

Sargent & Lundy and Synapse Energy Economics for Southern California Edison, February 2006, p. 212,.

[91] George Booras (EPRI) gives a construction time of about the same as a pulverized coal plant – 3 years. See George Booras, "Pulverized Coal and IGCC Plant Cost and Performance Estimates," presented at Gasification Technologies 2004, Washington, DC October 2004, p. 6. AEP estimates construction time to be 48 months.

[92] See EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38, p. 73.

[93] Ibid.

[94] AEP White Paper, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," 2005.

[95] See, EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

Suppliers (e.g., GE/Texaco, ConocoPhillips/E-Gas, and Shell) offer warranties and guarantees.

Maturity of the technology: Gasification technology has been in use since the 1920s, but IGCC electricity generation plants have a limited operating history.

Externalities: Particulate emissions into the air and discharge of solids into water are lower than other coal fired plants.[96] The sulfur in the fuel converts to hydrogen sulfide instead of sulfur dioxide. It is easier to capture hydrogen sulfide than sulfur dioxide; removal rates of 99% are common.[97] IGCC can also meet current emission standards for NOx without added control technology. Water usage is around 750 gallons/MWh for a 570 MW GE IGCC plant.[98] An IGCC plant requires at least 50 acres of land, not including buffer areas.[99] The land footprint AEP plans to use for a 629 MW plant is 390 acres. The footprint will vary depending on the land required for fuel unloading and storage and for ash disposal.

IGCC technology readily separates carbon dioxide from the syngas. The carbon dioxide can then be injected underground to keep it from entering the atmosphere. Emissions can be lowered to nearly zero by capturing and disposing of the carbon dioxide and using hydrogen as the power plant fuel. Such a plant is technically feasible now, but no hydrogen fueled combustion turbine is commercially available.[100] FutureGen is a partnership between DOE and private companies to develop a zero emissions IGCC plant with hydrogen fueled combustion.

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[96] Jay A. Ratafia-Brown, *et al.*, *An Environmental Assessment of IGCC Power Systems*, presented at the Nineteenth Annual Pittsburgh Coal Conference, 23-27 September 2002.

[97] George Booras, EPRI, *Pulverized Coal and IGCC Plant Cost and Performance Estimates*, presented at Gasification Technologies 2004, Washington, DC October 2004, p.6.

[98] Michael G. Klett, *et al.*, *Power Plant Water Usage and Loss Study*, prepared for NETL, August 2005. Document available at: http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/WaterReport_IGCC_Final_August2005.pdf.

[99] Wisconsin Public Service Commission, *Integrated Gasification Combined Cycle Technology Draft Reports: Benefits, Costs, and Prospects for Future Use in Wisconsin*, June 2006.

[100] Robert Charles, *et al.*, *Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016,* Sargent & Lundy and Synapse Energy Economics report prepared for Southern California Edison, February 2006, pp. 2-25.

The current public acceptability of IGCC is roughly the same as other coal-fired plants. Combining carbon dioxide capture and storage with IGCC could lead to greater public acceptability because of lower air emissions.

B. Nuclear generation

Overview: There are 104 commercial nuclear-fueled electricity generation units (nuclear power plants) operating in the United States.[101] Nuclear fuel generates approximately 20 percent of the nation's electricity. Worldwide, more than 400 nuclear power plants provide 16 percent of the global supply of electricity.[102] France has the highest percentage of nuclear power at approximately 79 percent.[103]

Most nuclear power plants have certain common features – the enriched uranium fuel, control rods, a cooling agent, and a moderator.[104] The rods regulate the fission of the uranium atoms. The heat produced by the fission in turn produces steam to operate the generating turbines. The coolant draws heat away from the reactor to prevent the reactor from overheating. The moderator slows the atomic process to increase the amount of energy released by the fissioning.

Nuclear power plants currently in operation around the world are of a number of different designs, including light water, heavy water, light water graphite, gas-cooled and fast-breeders reactors. Approximately 80 percent of the operating nuclear power plants are light water reactors.[105] Light water reactors are further classified as either pressurized water reactors (PWR) or boiling water reactors (BWR).

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[101] EIA, *Annual Energy Review, 2005*. "Table 9.2 Nuclear Power Plant Operations 1957 – 2005", July 2006, p. 275.

[102] World Nuclear Association, "World Nuclear Power Reactors 2005-06 and Uranium Requirements," November 27, 2006. Document available at: http://www.world-nuclear.org/info/reactors.htm. See also International Atomic Energy Agency, "Nuclear Power Reactors in the World", Reference Data Series No. 2, April 2006, table 10 "Reactors in Operation, December 31, 2005," pp. 21-42.

[103] World Nuclear Association, "Nuclear Share Figures, 1995-2005", May 2006. See www.world-nuclear.org/info/nshare.htm.

[104] The enriched fuel is approximately 4-5% uranium. Some nuclear power plants, such as the CANDU 6 design developed by Atomic Energy of Canada Limited, use natural unenriched fuel, which is about 0.7% U235.

[105] Light water is regular common water with the molecular formula H_2O. Heavy water molecules also occur naturally, but much less abundantly than light water molecules. Heavy water is still water -- it looks and tastes like regular water. The difference is that heavy water has a hydrogen atom with a mass twice that of the

“Generation III” is a common reference to the group of plant designs that have been constructed since the mid-1990’s. Generation III (or “Generation III+”) also includes those plants that are currently under construction or planned for construction in the next 10 or more years. Generation III does not refer to the nuclear-power plant designs still in the research and development phases. Industry observers project that these “Generation IV” designs are likely to be commercially available by 2030.[106]

Compared to Generation II designs (i.e. generally operational power plants built prior to 1990), Generation III plants have a greater emphasis on *passive safety*. A passive safety feature is one that is fully effective or that engages without operator action or electronic feedback. Passive safety features make use of the laws of physics and other highly predictable behaviors of materials, components, processes, and systems. One example would be the use of a liquid sodium pool instead of (or in conjunction with) a pressurized water-cooling system. In a PWR, the cooling system relies on water contained in a high-pressure system. The water would boil away quickly if the pressure system failed. If the reactor core were submerged in a large pool of liquid sodium, the natural heat absorption and boiling temperature properties of the liquid sodium would passively act to prevent overheating.

Load-service function: The capacity of nuclear power plants in the United States ranges from a low of 476MW to a high of 1314MW, with more than half of the units in the range of 1016 to 1314 MW.[107] Nuclear power facilities generally operate as baseload units.[108] Starting an off-line reactor requires at least 24 hours and often more

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hydrogen atom in regular water. The heavy hydrogen is commonly called deuterium. Heavy water is represented with either the molecular formula of ^2H_2O or D_2O. The significant increased mass of the D_2O gives heavy water different properties than H_2O. Heavy water boils at a higher temperature and has a lower critical temperature than light water.

[106] See: James A. Lake, Ralph G. Bennett and John F. Kotek. “Next-Generation Nuclear Power," *Scientific American*, January 2002. Also see: World Nuclear Association, *Generation IV Nuclear Reactors*, July 2006. Also see: Office of Advanced Nuclear Research, DOE Office of Nuclear Energy, Science and Technology: Idaho National Laboratory, *Generation IV Nuclear Energy Systems Ten-Year Program Plan, V. 1*, March 2005.

[107] EIA, *Annual Energy Review, Monthly Nuclear Generation by State and Reactor 2005,* released 2006. Data available at: http://www.eia.doe.gov/cneaf/nuclear/page/nuc_generation/usreactors2005.xls.

[108] Some nuclear power plants are used in a load-following mode rather than a straight baseload.

time.[109] This long start time means that a nuclear power plant is not a practical response to intermediate or peak demands.

Time to construct: Assuming a greenfield start (i.e., constructing on a location where no plant has existed before), it takes approximately four to six years of actual construction time to build a typical Generation III nuclear power plant. The mean period of time between the construction start date and the date of final connection to the grid for all operational nuclear power plants units in the United States is approximately 9 years. For nearly 25 percent of the currently operational units the period of time from construction start to operation was 12 or more years.[110]

Cost to construct: Construction has not started on a new nuclear power plant in the United States since 1972, so cost estimates for new plants must rely in some part on analysis of international construction data. The Energy Information Administration (EIA) has projected the overnight greenfield construction cost for a 1,000 MW nuclear unit at approximately $1.85 billion or $1,849/kW.[111] In August 2005, Tennessee Valley Authority (TVA) delivered a report to United States Department of Energy (DOE) estimating overnight construction cost at $1,708/kW (updated to 2006 dollars).[112]

Operational life: Most of the nuclear power plants currently in operation in the United States were originally licensed by the Nuclear Regulatory Commission (NRC) for a 40-year operational life. However, updates, engineering, and analysis improvements have lead to longer actual plant lives. The NRC has issued renewal licenses of up to 20 additional years to many plants in the United States.[113]

Fuel costs: Approximately two-thirds of the nuclear fuel cost is in the enrichment and fabrication process. In 2006, the approximate fuel cost was

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[109] Gerry Adamski, Ronaldo Jenkins, and Paul Gill, "Nuclear Plant Requirements during Power System Restoration", IEEE Transactions on Power Systems, Vol. 10, No.3, 1995, p.1486.

[110] The periods of time from construction start to grid connection are calculated using data from the International Atomic Energy Agency's list of "Reactors in Operation, 31 December 2005". See "Nuclear Power Reactors in the World", Reference Data Series No. 2, April 2006.

[111] EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

[112] TVA, "New Nuclear Power Plant Licensing Demonstration Project ABWR Cost/Schedule/COL Project at TVA's Bellefonte Site", August 2005, pp. 4.2-3.

[113] U.S. Nuclear Regulatory Commission, *Status of License Renewal Applications and Industry Activities,* retrieved December 4, 2006 from http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

$0.47/MMBtu, including the cost of spent fuel management and disposal.[114] Assuming a heat exchange rate of 10,400MMBtu/kWh, the cost of fuel per kWh of generation is $0.0049, or $4.89/MWh.[115]

Fuel costs of a nuclear power plant are a relatively small portion of the total cost of the electricity produced as compared to coal and natural gas.[116] Consequently, fluctuations in fuel costs have a smaller effect on the cost of electricity produced with nuclear fuel - relative to coal or natural gas. A 100 percent increase in the price of uranium might only increase the cost of electricity by about eight percent.[117] Another buffer from the effects of price volatility is the long fuel purchase interval that is common for nuclear plants. A typical light water reactor nuclear power plant refuels only every 18-24 months. This long interval could serve to give nuclear power plants sufficient time to avoid many of the fluctuations of spot market prices

Fuel dependability: Estimates of the remaining recoverable uranium resources vary widely, making it difficult to offer a reliable estimate of the dependability of the fuel supply. The World Nuclear Association asserts that the supply of uranium is sufficient to sustain the demand.[118] However, since most nuclear plants require enriched and specially

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[114] The inclusion of spent fuel management and disposal does not include any costs associated with delays in permanent storage or costs of any unplanned extensions of on-site interim storage. Fuel costs reporting and forecasts were examined from a number of different sources including: (1) EIA, *Annual Energy Outlook 2006 with Projections to 2030*, December 2005; (2) Uranium Information Centre, *The Economics of Nuclear Power, Briefing Paper 8*, Melbourne, Australia, November 2006; (3) Nuclear Energy Institute, Financial Center reports as of November 2006, available at: http://www.nei.org/index.asp?catnum=1&catid=4.

[115] See, EIA, *Assumptions to the Annual Energy Outlook, 2006,* Table 38.

[116] See Nuclear Energy Institute, *Fuel as a Percentage of Electric Power Industry Production Costs 2005.* Document available at: http://www.nei.org/documents/Fuel_as_Percent_Electric_Production_Costs.pdf.

[117] Assuming that enrichment and fabrication account for two-thirds of the cost of the reactor fuel, a 100 percent increase in the price of uranium would alone cause only a one-third increase in the price of the reactor fuel. Then assuming the cost of reactor fuel accounts for approximately 25 percent of a nuclear power plant's cost to produce electricity, the 100 percent increase in the price of uranium increase the cost of electricity by about eight percent.

[118] World Nuclear Association, *Position Statement: Can Uranium Supplies Sustain the Global Nuclear Renaissance?* September 2005. See http://www.world-nuclear.org.

fabricated fuel assemblies, assessing fuel supply requires an examination of both raw material supply and fuel production capacities.

An increase in reprocessing of spent fuel assemblies, new plant designs that reduce the need for enriched fuel, improved enrichment process, and use of other raw fuel materials could significantly extend the nuclear fuel supply. For example, if relative to other reactor types, the percentage of fast breeder reactors (which can self breed a portion of the fuel supply) where higher, the existing supply of raw uranium would be depleted more slowly.

Dependability of the plant: The average capacity factor for nuclear power plants in the United States is approximately 90 percent with some reactors achieving more than 97 percent.[119] The average availability factor for nuclear power plants in the United States is also approximately 90 percent.[120] These two factors appear to be approaching the practical threshold given that a nuclear power unit must typically refuel every 18-24 months.

Maturity of the technology: The Generation II and III nuclear power plants technology is proven in the United States and around the world. Approximately 75 percent of the U.S. nuclear power plants have been operating for 20 or more years, with more than 40 of these plants operating 30 years or more. The first Generation III plants built are now ten years old.[121] The cumulative hours of successful operation and the high operating capacity and availability averages further demonstrate the maturity of the technology.

Unique regulatory issues: There are a number of special regulatory issues involving the construction and operation of a nuclear power plant. The main issues can be placed in two categories – plant design and operations.

The Nuclear Regulatory Commission (NRC) has certified four advanced Generation III reactor designs. An entity building a plant using one of the certified designs may receive authorization to proceed directly to the site-specific certification processes. Site-specific certification includes the resolution of site safety, environmental protection, and emergency preparedness issues.

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[119] EIA, *Annual Energy Outlook 2006 with Projections to 2030*, December 2005.

[120] International Atomic Energy Agency, *Nuclear Power Plants Information, Energy Availability Factor 2003-2005.*

[121] EIA, *Electric Power Annual with data for 2005*, Table "Existing Generating Units in the United States, by State, Company and Plant, 2003," released October 4, 2006. See also Uranium Information Centre Ltd., "Nuclear Power in the World Today: Nuclear Issues Briefing Paper 7", Melbourne, Australia, September 2006.

A major regulatory concern involving the operation of a nuclear power plant is the current and future handling of spent fuel assemblies (nuclear waste). The long-term delays in the creation of a permanent nuclear waste storage facility have nearly exhausted the temporary storage facilities on the power plants sites.[122] Utilities have claimed – and in some cases, filed for recovery of – hundreds of millions of additional on-site storage costs caused by the federal government's delay in opening a permanent storage facility.[123] The financial risks associated with the continued uncertainty of nuclear waste storage impede future nuclear plant construction.

The Energy Policy Act of 2005 (EPAct) provides incentives for nuclear power. Among other incentives, EPAct provides a production tax credit of $0.018/kWh from the first 6,000MW of new plant operation and risk insurance coverage of regulatory delay costs for the first six new advance design plants.

Externalities: Operating nuclear power plants do not emit greenhouse gases. A normally operating nuclear power plant does produce low-level radioactive emissions, but these emissions are similar to or less than the radioactive emissions of a coal-fired power plant of the same capacity rating.[124]

Nuclear power plant commercial operations total more than 12,000 cumulative reactor-years. The worldwide operational record of commercial nuclear power plants includes two major core-melting accidents – 1979 Three Mile Island plant[125] and the

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[122] For a summary of the storage availability at U.S. nuclear power plants see; Nuclear Energy Institute, *Status of Used Nuclear Fuel Storage at U.S. Commercial Nuclear Plants*, October 2005. See also, Uranium Information Centre Ltd., "Nuclear Power in the World Today: Nuclear Issues Briefing Paper 7", Melbourne, Australia, September 2006.

[123] See, for example, the announced settlement agreement of Exelon Corp. and the U.S. Department of Justice, announced on August 10, 2004. See Mark Holt, "CRS Report for Congress: Civilian Nuclear Waste Disposal," (as updated September 19, 2006) RL33461, p. 4. Document is available at: http://ncseonline.org/NLE/CRSreports/06Sep/RL33461.pdf.

[124] For discussions of nuclear plant radioactive emissions see: (1) U.S. Nuclear Regulatory Commission, "Fact Sheet on Radiation Monitoring at Nuclear Power Plants and the "Tooth Fairy" Issue", January 2005; (2) U.S. Environmental Protection Agency, Office of Radiation and Indoor Air (6608J) "RadTown USA, Nuclear Power Plants", EPA 402-F-06-019, April 2006; (3) Gabbard, Alex. "Coal Combustion: Nuclear Resource or Danger?" *Oak Ridge National Laboratory Review*, Volume 26, Nos. 3 & 4, Summer/Fall 1993.

[125] According to the NRC, the partial meltdown of the Three Mile Island Unit 2 reactor core caused no deaths or injuries; most of the radiation was contained within the structure. Estimates of the average radiation doses to people in the surrounding area were

1986 Chernobyl plant[126] accidents. Historically, nuclear power plants have a better major accident record than other fossil fuel or hydro power plants.[127]

In addition to the operational safety concerns of a nuclear power plant, there has been heightened public concern since 2001 on potential terrorist acts against nuclear plants. The dangers include radioactive disasters caused by an intentional attack, infiltration, or sabotage of nuclear reactors, fuel and waste storage locations, and transportation facilities. According to the NRC, there is a general credible threat of a terrorist attack on nuclear power plants.[128] There are a number of conflicting estimates of the potential results of such intentional acts.[129]

C. Wind generation

Overview: Most wind facilities in the United States use blades that are aeronautically designed, with a shape similar to airplane propellers, to collect the wind's

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about 1 millirem. For comparison, a chest x-ray would be a does of approximately 6 millirems. For more information see U.S. Nuclear Regulatory Commission, "Fact Sheet on the Accident at Three Mile Island," March 2004.

[126] The Chernobyl accident did release a large amount of radioactive material into the environment and resulted in, at least 28 near-term deaths. Several million people received doses of radiation ranging from very small to more than 30 times the natural background level of annual radiation dose. Most analyses attribute the accident largely to plant design. For more information see; *Chernobyl's Legacy: Health, Environmental and Socio-Economic Impacts and Recommendations to the Governments of Belarus, the Russian Federation and Ukraine*, *Second Revised Edition*. The Chernobyl Forum: 2003-2005.

[127] Hirschberg, S., G. Spiekerman, and R. Dones. "Severe Accidents in the Energy Sector, Comprehensive Assessment of Energy Systems", *Paul Scherrer Institut*, Switzerland, 1998. In this study, the authors consider major power plant accidents resulting in death and injury between 1945 -1996. The authors also extrapolate the long-term injury and death effects for the Chernobyl accident to 70 years.

[128] United States Government Accountability Office, *Nuclear Power Plants, Report to the Chairman, Subcommittee on National Security, Emerging Threats, and International Relations, Committee on Government Reform, House of Representatives* (GAO – 06 – 388), March 2006, p.1.

[129] One of the larger studies examined the effects of a direct high-speed impact of a fully-fueled jet. This study concluded that jet impacts would not result in release of radioactive materials. See, Nuclear Energy Institute, "Deterring Terrorism: Aircraft Crash Impact Analyses Demonstrate Nuclear Power Plant's Structural Strength", December 2002.

kinetic energy and convert it to mechanical energy, which in turn produces electricity. The drive shaft connected to the blades turns an electric generator to produce electricity.

The capacity of a wind facility to produce electricity depends on the height of the wind machine, the area swept by the blades, the speed of the wind, among other factors.[130] Advances in wind technologies will continue to drive down the costs of wind power, making it more economical in areas with less desirable wind characteristics. Technological advancements since the 1980s have contributed toward reducing the unsubsidized cost of wind power from around 40 cents per kWh to the 4-6 cents per kWh range by 2005.[131] The additional intermittency and transmission costs that wind imposes on a power system have made wind energy less competitive with traditional sources of electricity.[132] These supplemental costs partially explain why wind energy currently provides only a small portion of the total electricity generated in the United States. Finally, the competitiveness of wind power relative to other fuel sources depends on the federal production tax credit, which currently stands at 1.9 cents per kWh. In the past when this credit had expired, investments in new wind capacity fell.

California, Iowa, Minnesota and Texas are the states with the most new wind capacity installed since 1998.[133] EIA projects the generation of wind power will increase at the average annual rate of 4.2 percent during the period 2005-2030. This corresponds to wind's share of total net electricity generation increasing to 1.1 percent by 2030, compared with 0.4 percent for 2005.[134]

Load-service function: Wind power is intermittent power, diminishing its capacity value during peak periods. System operators consider wind energy an "as-available" source of power, difficult to schedule more than a few hours in advance. This characteristic requires a power system operator to incur additional costs for ancillary services such as regulation service – the management of minute-to-minute load imbalances. The size of these regulation costs varies and is the subject of debate.[135]

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[130] For an overview of wind technology, see http://www.awea.org/faq/index.html and http://www.nrel.gov/wind/consumer_home_business.html.

[131] See Blair Swezey, "Renewable Energy in Today's Power Markets," NARUC Summer Meetings, July 2004.

[132] See Joe Darmstadter and Karen Palmer, "Renewable Sources of Electricity: Safe Bet or Tilting at Windmills," *Resources*, Issue 156 (Winter 2005), 24-27.

[133] See American Wind Energy Association, *Wind Energy Fast Facts*, 2006.

[134] EIA, *Annual Energy Outlook 2006*, p. 81.

[135] See, for example, J. Charles Smith, "Wind Energy Development in the U.S.," Presentation at the OC/PC Meeting, September 16, 2006; Michael Milligan *et al*., "Wind Energy and Power System Operations: A Survey of Current Research and Regulatory

Wind's output variation also deviates from the power system's load variations; this reduced "load-following" capability further diminishes wind's value for load service, relative to other, more readily dispatchable sources.[136] This "intermittency" cost to a power system depends on, among other things, the system's generation mix. Lower costs would occur when the system has a higher mix of generation facilities with fast ramp rates, such as gas turbines and hydropower facilities; the reason is that these facilities can quickly compensate for any shortfalls in wind generation. Intermittency costs may grow as the mix of wind energy on a power system rises significantly above the current level.

Wind facilities are available in sizes up to 50 MW. Power system operators can choose the size that best fits their systems. The range of capacity factors across wind facilities vary widely, depending largely on wind conditions and the characteristics of the wind turbine. In 2004, according to the Electric Power Research Institute (EPRI) wind facilities had an average capacity factor of 30 percent.[137] This 30-percent capacity factor is low compared to other generation facilities that have large capital costs and low operating costs (e.g., pulverized coal-fired units). EIA projects higher capacity factors in the future. In its reference case, EIA projects a capacity factor of 44 percent for the best wind class by 2010, due to a combination of taller towers, more reliable equipment and advanced technologies.[138] Increasing the capacity factor improves the economic attractiveness of wind energy. EPRI estimated that increasing the capacity factor from 29 percent to 42 percent would reduce the unsubsidized cost of wind power from 7.5 cents per kWh to 5.5 cents per kWh; a relapse with the capacity factor achieving 20 percent would raise wind's cost to 10 cents per kWh.[139] According to EPRI studies of levelized costs of electricity, if wind energy could obtain a capacity factor of over 40 percent, its levelized cost of electricity would be comparable with other technologies, even absent a production tax credit.[140]

Actions," *The Electricity Journal* 15, Issue 2 (March 2002), pp. 56-67; Joseph F. DeCarolis and David W. Keith, "The Costs of Wind's Variability: Is There a Threshold?" *The Electricity Journal* 18, Issue 1 (January/February 2005), pp 69-77; and Ed DeMeo, "Integrating Wind Power into the Electric Power System," Presentation at the meeting on Unleashing the Potential: Wind Energy in Michigan, October 21, 2005.

[136] Load following refers to the response of a system operator to meet variations in electricity demand by scheduling and committing generating units for operation based on forecasted load changes over temporal cycles adjusted for random variations.

[137] See Steve Specker, "Generation Technologies in a Carbon-Constrained World."

[138] EIA, *Assumptions for the Annual Energy Outlook 2006*, March 2006, p. 135.

[139] Steve Specker, "Generation Technologies in a Carbon-Constrained World."

[140] Ibid.

Time to construct: In its long-term projections, EIA analyzes the economics of new wind facilities assuming a capacity of 50 MW.[141] EIA estimates that a 50-MW facility would have a three-year time period between the ordering of a facility and its completion. According to another source, the construction period for wind projects ranges from five to twelve months, depending on project size, weather conditions and terrain.[142]

Cost to construct: The EIA analysis of a 50 MW plant assumes construction costs of $1,157 per kW.[143] Because of economies of scale, the average cost of wind power decreases with the size of the facility.

Operational life: The service life of a wind facility is approximately twenty years; refurbishment of the turbine generators and other equipment can add as much as ten years to the service life.

Fuel costs and supply: Although wind facilities use no fuel sources, intermittency requires a system operator to deploy back-up facilities that burn fossil fuels. One potential benefit of wind energy is the displacement of power from fossil-fuel generation facilities that emit air pollutants and toxic wastes.

Dependability of the plant: Operational experience has shown that the availability factor of state-of-the-art wind turbines is around 98 percent. This statement considers only the mechanical aspects of a wind turbine. For example, a 98 percent availability factor means that a turbine is out of service for maintenance or repairs two percent of the time. If availability takes into account wind conditions, then a wind turbine could have a much lower availability factor, since the turbine may sit idle for an appreciable period even when it is ready to run if there is not sufficient wind to power it.

Wind availability and wind speed fluctuate and have limited predictability. Another measure of dependability that is helpful for understanding wind power is the effective load-carrying capability (ELCC). ELCC measures the amount of incremental load for which a new facility can handle without reducing overall power system reliability.[144] A higher ELCC means a higher capacity value for a new facility. Disagreements arise over

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[141] EIA, *Assumptions for the Annual Energy Outlook 2006*, p. 73.

[142] Global Energy Concepts, *Wind Project Lifecycle: Overview*, prepared for the New York State Energy Research and Development Authority, October 2005.

[143] EIA, *Assumptions for the Annual Energy Outlook 2006*, p. 73.

[144] See Ed Kahn, "Effective Load Carrying Capability of Wind Generation: Initial Results with Public Data," presentation at the California Energy Commission Renewables Committee Workshop, February 20, 2004.

the contribution of a wind facility in enhancing system reliability (i.e., in reducing loss of load probability (LOLP), which is the probability that demand exceeds supply within a given period of time).[145] Because of wind intermittency, the installed capacity of a wind facility contributes less to ELCC than the equivalent installed capacity of other generation technologies. ELCC estimates for wind facilities range fall within the range of 0-40 percent, whereas gas-fired and other fossil fuel generating facilities most frequently have an ELCC close to 80-90 percent.[146]

Maturity of the technology: Wind technologies are mature given their wide adoption throughout the world and more than a century of operating experience. Despite this long history, wind technologies will continue to undergo improvements making them more economical in the future. One change will facilitate interfacing wind facilities with the power grid. Another will improve turbine design by installing higher turbine towers and larger blades, both reducing operating costs and increasing reliability.[147] A major technological advancement will involve the design of wind turbines to operate economically at sites with low wind speeds and closer to load centers.[148] Overall, advancements in wind technologies, from the combination of research and development activities and increased market penetration (i.e., learning by doing), will produce improvements in both cost and operating performance.

Externalities: Wind power has more benign environmental effects compared with fossil-fuel generation technologies. Operation of wind facilities emits no air or water pollutants of any kind, and produces no toxic wastes or negative health impacts. On the other hand, one common problem with wind facilities is their noise, although new facilities have reduced this problem.

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[145] EIA defines reliability in terms of security and adequacy. Security is "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements." Adequacy refers to "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably unscheduled outages of system elements." Glossary available at: http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html.

[146] See Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, Lawrence Berkeley National Laboratory (LBNL-58450), August 2005; and California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, prepared for Docket 02-IEP-01, June 5, 2003, Appendix C and D.

[147] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, I-37; and American Wind Energy Association, *The Economics of Wind Energy*, February 2005.

[148] Dan Arvizu, "Fulfilling the Promise of Renewable Energy: A Look at the Future," Resources for the Future Forum, June 21, 2005.

Large wind facilities occupy more land area than fossil fuel facilities, but most of the land (between the towers) is available for other uses. Facilities are typically located in areas with high wind speeds, making wind energy more economical. Most facilities reside in remote areas with new transmission lines required to deliver the power to load centers. These new lines affect the economics of wind facilities, since average costs could increase with a low capacity factor. With current technology, wind energy output increases by the cube of the wind speed. Increasing the average wind speed just from 13 miles per hour to 15 miles per hour, for example, augment electricity output by over 50 percent.[149] Sites suitable for electric generation typically require sustained winds averaging, at the minimum, 14-15 miles per hour.[150]

In the future, if wind facilities locate near urban areas, they will provoke more opposition from local citizens than seen so far. Wind energy has met with mixed public acceptability up to now. Several wind projects have faced opposition because of their negative aesthetic effect and other siting concerns.[151] Especially in New England, local citizens and community groups have opposed the siting of new wind facilities.[152] The possibility for harm to birds and bats is another negative externality for large wind power units.

D. Pumped-storage hydropower

Overview: Electricity cannot be stored directly. Electricity must be produced at exactly the level to match demand at any particular moment. It is possible, however, to use electricity to store up potential energy to be released later and converted back to electricity. Pumped-storage hydropower is the most commonly used storage technology deployed on electric power systems.[153] This technology uses water from an upper

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[149] See American Wind Energy Association, *The Economics of Wind Energy*.

[150] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-24.

[151] Alan Nogee, "State Renewable Electricity Standards: Projections, Policy Details, and Experiences to Date," Presentation at the Harvard Electricity Policy group 39th Plenary Session, May 20, 2005.

[152] In one instance local-citizen groups and environmentalists opposed the building of the Cape Cod wind project in part because of the claimed impairment of coastal views. Rick Klein, "Kennedy Faces Fight on Cape Wind," *Boston Globe*, April 27, 2006.

[153] Compressing air in underground geological formations for release during peak demand is another approach to storing energy, but pumped-storage hydropower is currently the only commercially viable storage technology. For an overview of the pumped-storage technology, see:

reservoir through the blades of a turbine to generate electricity, typically during peak periods. The units pump the water into the upper reservoir from a lower reservoir during off-peak periods, such as nights and weekends. Although electricity itself is not stored, the potential energy is stored and can be released to be converted back to electricity without the use of fuel. Pumped storage serves as a load management tool by lowering the amount of power that other generation units must provide during the periods of highest demand (and highest cost) for electricity.

Today, pumped storage comprises less than two percent of the total generating capacity in the United States.[154] California has over 4,000 MW of pumped storage (which approximates 20 percent of total pump storage capacity in the U.S.), with two proposed projects expected to add as much as 900 MW of generating capacity before the end of this decade.[155] Pumped-storage net summer capacity throughout the United States has remained stable since 1990. Limitations on the expansion of pumped storage facilities stem from the availability of suitable sites where geological and ecological conditions allow for their construction and operation.

Load-service function: Pumped storage can respond quickly to sudden changes in electricity demand, making it especially valuable for meeting peak demand and the provision of ancillary services. On average, it takes between one and four minutes to activate a pumped storage facility from a cold start and less than thirty minutes to transfer the facility from pumping water to generating electricity. Pumped storage has become more economically attractive as wholesale electricity prices during peak periods increase relative to off-peak power and as wholesale prices become more volatile. Economically, storage plays an arbitrage function by exploiting short-term differentials in electricity prices.[156] Price differentials reflect the gap between the cost of electricity in pumping the water to the upper reservoir and the market price or the value of the electricity generated during peak periods. Pumped storage can help make wind energy more dispatchable. It can also absorb electricity generation from wind facilities during high-wind periods so as to minimize any system operational problems.

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http://www.duke-energy.com/about/energy/generating/pumped_storage, and http://www.electricitystorage.org/tech/technologies_technologies_pumpedhydro.htm.

[154] See http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html.

[155] See California Energy Commission, *Integrated Energy Policy Report*, CEC-100-2005-007CMF, November 2005, pp. 146-147.

[156] See, for example, Frank Graves *et al.*, “Opportunities for Electricity Storage in Deregulating Markets,” *The Electricity Journal* 12, Issue 8 (October 1999), pp. 46-56.

Functioning largely as a peaking facility, pumped storage plants have low capacity factors, in the range of 15-35 percent.[157] The sponsors for a proposed new pumped storage facility in California estimated a capacity factor of 36 percent. Although a pumped-storage facility uses no fuels at the time the stored water falls, the process of pumping the water into storage in the upper reservoir requires internal generation from existing power plants. New pumped-storage units have efficiency levels as high as 85 percent, meaning that this percentage of electricity used to pump water is "returned" in the form of generated power. The peculiarity of pumped storage is its negative net electricity generation (i.e., where more electricity is needed to pump water to an upper reservoir than the actual electricity later generated by the same pumped storage facility).

Time to construct: Limited data is available. The sponsors of a proposed new facility in California (the Lake Elsinore plant) estimate the construction time at four and a half years

Cost to construct: Pumped-storage facilities vary in size. In the United States, installed plant capacity ranges from 31 MW to over 2,880 MW, with the median plant close to 1000 MW. The Lake Elsinore plant has a capacity of 500 MW. The sponsors estimate the construction time at four and a half years, with a cost of $1.115 billion (in 2005 dollars) or $2,379 per kW (in 2006 dollars). When estimating the value of a pumped storage plant, regulators should consider its capital costs in comparison to peak power costs and its value as readily available reserve capacity for grid management. Pumped-storage facilities generally have higher construction costs and longer lead times than alternative peaking facilities such as steam combustion turbines, which have construction costs per kW that is typically less than 20 percent of the cost for the Lake Elsinore facility).

Operational life: Studies analyzing new pumped storage facilities assume a plant service life up to sixty years.[158] The sponsors of the Lake Elsinore requested an initial permit of fifty years for the plant.[159]

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[157] See Dale T. Bradshaw, "Pumped Hydroelectric Storage (PHS) and Compressed Air Energy Storage (CAES)," presentation at the IEEE PES Meeting on Energy Storage, July 19, 2000.

[158] See, for example, Paul Denholm and Gerald L. Kulcinski, "Life Cycle Energy Requirements and Greenhouse Gas Emissions from Large Scale Energy Storage Systems," *Energy Conversion and Management*, 45, Issues 13-14 (August 2004), pp. 2153-72.

[159] Information on the Lake Elsinore plant is contained in Federal Energy Regulatory Commission and U.S. Department of Agriculture, *Draft Environmental Impact Statement for Hydropower License: Lake Elsinore Advanced Pumped Storage Project, FERC Project No. 11858*, Docket No. P-11858-002, February 2006.

Fuel costs and fuel dependability: Pumped storage systems do not use fuel directly, but there is a cost for the electricity associated with pumping water to create the stored capacity. Since the plant typically pumps during periods of low electricity demand, the cost of the electricity needed for pumping will be low relative to other periods of demand. Similarly, the dependability of electricity for pumping is high because the pumping usually occurs when generating capacity is readily available.

Dependability of the plant: Pumped-storage facilities are reliable generating facilities, as long as the upper reservoir receives adequate water pumped from the lower reservoir. These facilities have availability factors of 90-95 percent and forced outage rates of less than 1.5 percent.[160] Historically a lack of water for pumping has not posed a serious problem for pumped storage facilities in the United States. The availability of electricity to pump water to the upper reservoir also poses no problem since pumping mostly occurs during off-peak periods when ample power is normally available.

Maturity of the technology: Pumped storage is a mature technology, featuring facilities that have decades of operating experience throughout the world with minimal operating problems.

Externalities: Local citizens have accepted the siting of pumped storage facilities with some reservations. Their concerns include the assurances of no adverse effects on the local wildlife habitat, recreational activities, and the water quality of local creeks and lakes. Improperly maintained and operated facilities have resulted in reservoir failure and flooding in past cases.

Pumped storage facilities occupy large tracts of land. The proposed Lake Elsinore facility referenced above would inhabit over 2,410 acres of land. In addition, the facility would require large amounts of water (namely, 5,500 acre-feet) for the initial filling of the upper reservoir. The Environmental Impact Statement (EIS) for the project expressed concern over the location of the upper reservoir in an area used for recreation and with a diverse ecosystem.

E. Miscellaneous generation technologies

In addition to the electric generation technologies discussed above, there are several others that are responsible for a small share of generating capacity. The technologies described below typically feature higher power costs compared to the technologies described above or their use is constrained by geography, as is the case with geothermal power and solar power. The technologies described below cannot be grouped together as "new" or "emerging" because some of them have been around for decades. On the other hand, most of the technologies are not fully mature because their engineered efficiency and cost profiles will likely improve with time and wider use. The report

[160] Dale T. Bradshaw, "Pumped Hydroelectric Storage (PHS) and Compressed Air Energy Storage (CAES)."

offers less detailed coverage of the technologies below and omits entries for the criteria for comparison for which the authors identified no data.

1. Photovoltaic power

Overview: Photovoltaic (PV) systems consist of arrays of modules that absorb solar radiation and causes current to flow between oppositely charged layers of the module. The solar energy converts to electricity without moving parts. The PV material can be fixed in place or mounted on single or dual axis sun trackers that tilt toward the sun seasonally (north to south), daily (east to west), or both for maximum exposure to the sun. A complete PV system includes concentrator modules, support and tracking structures, a power-processing center, and land.[161]

Load-service function: High levels of sunlight to power PV systems tend to correspond to high levels of demand for electricity, so PV generation in the U.S. is used for providing peak power and intermediate daytime load.[162] One advantage of PV systems is that they can be built in arrays of almost any size; the large arrays currently in operation supply around 1 MW of power.[163] Most arrays are residential (about one kW) or commercial (one to several hundred kW) alternatives to retail electricity.[164]

Time to construct: Photovoltaic power plants require a construction time of 2 years.[165]

Cost to construct: The overnight cost for a photovoltaic electric generation plant is $4,222 /kW, according to the EIA.[166]

Operational life: PV generation systems typically last 20 to 40 years.[167]

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[161] See National Renewable Energy Laboratory. *Power Technologies Energy Data Book* (cited hereafter as, NREL-*PTED),* 3ed. NREL/TP-620-37930, April 2005; and NREL U.S. Climate change Technology Program, *Technology Options: For the Near and Long Term*, DOE/PI-0002, November 2003; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-22 and 5-23.

[162] See NREL-*PTED*, p 25.

[163] United Nations Environment Program, Division of Technology, Industry and Economics, “Energy Technology Fact Sheet: Photovoltaics,” 2004. Document available at: http://www.unep.fr/energy/publications/pdfs/pv.pdf.

[164] Ibid.

[165] See EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38.

[166] Ibid.

Fuel costs: PV systems do not have fuel costs since they rely on solar radiation.

Dependability of fuel supply: The amount of sunlight available for PV arrays varies by time of day, latitude, cloud cover, and local shading. According to the National Renewable Energy Laboratory (NREL), however, nearly all locations in the U.S. have enough sunlight for PV electric generation to occur.[168] PV arrays tend to have higher capacity factors in sunny areas, making them the most economically attractive locations for new PV systems.

Dependability of the plant: PV systems have few moving parts, which minimizes their need for maintenance. Similar to wind, PV arrays have very high mechanical availability factors (approaching 99%), but much lower capacity factors (around 16%) partly because they provide power only intermittently following the availability of sunlight.[169]

Maturity of technology: Most PV arrays installed to date are made of crystalline silicone, a technology NREL considers relatively mature.[170] Photovoltaic arrays can also be made of utility scale thin-film and concentrator cells.[171] PV conversion efficiencies have improved 50% over the past ten years.[172] Current PV electric conversion efficiency for crystalline silicon, thin film, and concentrator systems is 14.1, 8.8, and 17.1 percent, respectively.[173]

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167 See Tom Markvart, and Luis Castaner, eds. *Solar Cells: Materials, manufacture and operation,* Elsevier Science, Inc, New York, New York, 2005; Czanderna, A. W. and Jorgensen, G. J., *Accelerated life testing and service lifetime prediction for PV technologies in the twenty-first century,* NREL, Golden, Colorado, 1999; Realini, A., *et al*., *Mean time before failure of photovoltaic modules (MTBF-PVm*), Swiss Federal Office of Energy, Canobbio, Switzerland, 2002.

168 NREL-*PTED*, p. 26. The amount of sunlight in Kansas, for example, varies only 25%.

169 See Avery Lovins, *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, Snowmass, Colorado, Rocky Mountain Institute, 2002; and Itron, "CPUC Self-Generation Incentive Program Fourth Year Impact Report, submitted to Southern California Edison and the Self-Generation Incentive Program Working Group, April 2005, p. 1.4.

170 NREL-*PTED,* p 28.

171 Ibid.

172 NREL-*PTED*, p. 26.

173 NREL-*PTED*, p 35 and *Renewable Energy Technology Characterizations*, EPRI TR-109496, 1997.

Externalities: PV arrays avoid negative externalities like fuel wastes, air pollution, or greenhouse gasses. Small residential and commercial systems can be located inconspicuously (e.g., on rooftops or modeled to look like windows). Owners of large arrays can choose to locate them away from population centers, assuming the transmission service to do so.

2. Concentrated solar power

Overview: Concentrated solar power (CSP) systems produce electricity with sun-tracking mirrors that concentrate the sun's energy to heat a working fluid. The working fluid is used to create steam that produces electricity in conventional steam or gas turbines. CSP systems can also produce electricity on cloudy days by using stored heat energy or substituting fossil fuels to heat the working fluid.[174]

There are three types of CSP systems: parabolic trough, power tower, and dish engine. Parabolic trough CSP plants range in size from 10 to 100 MW; power tower CSP systems vary from 30 to 200 MW; and dish/engine systems from 2 to 25 kW.[175] According to NREL data, the capacity factor for parabolic trough, power tower, and dish/engine CSP plants are between 30 and 50 percent.

Load service function: CSP electric generation in the U.S. has been used primarily to supply bulk electricity for the grid in the southwest. These systems, however, were installed under power supply purchase rates that are no longer typical, according to the NREL. As it stands, CSP technology is too expensive to compete in domestic markets without subsidies.[176]

Time to construct: Solar thermal generation plants have a 3 year construction time.[177]

Cost to construct: The overnight cost of a solar thermal electric plant, a general category, is in the range of $2,745-$3,234/kW.[178]

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[174] NREL-*PTED*, p 19.

[175] See NREL-*PTED*, p23 and *Renewable Energy Project Information System* (REPiS), Version7, NREL, 2003; and *Renewable Energy Technology Characterizations*, EPRI TR-109496.

[176] NREL, *PTED*, p 26.

[177] EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38.

[178] Ibid.

Operational life: The operational life of a solar thermal electric generation plant is about 30 years.[179]

Fuel costs: CSP systems do not have fuel costs since they rely on solar radiation.

Maturity of technology: CSP generation is an immature technology.

Externalities: Like PV arrays, CSP systems avoid negative externalities like fuel wastes, air pollution, or greenhouse gasses.

3. Biomass power

Overview: Biopower refers to electric power generated from converted vegetation (i.e., biomass). The most common biomass resources today are waste wood and agricultural crop residues. Current research, however, is exploring the production of switch grass and other crops for the specific purpose of biomass conversion for electricity production.[180]

Biopower generation is a two step process. The first step is to convert biomass feed stock into what is known as biofuel. Feed stock can be converted into biofuel in one of three ways: homogenization, gasification, and anaerobic digestion. Homogenization is a process by which feedstock is made uniform for further processing or combustion. In the gasification process, biomass is converted into fuel gas that is used as a substitute for fossil fuel in combustion turbines. Anaerobic digestion converts agricultural and animal waste into biogas that can be used in standard or combined heat and power (CHP) applications. Anaerobic digestion also occurs in landfills as part of the decomposition process. Biogas can be converted into liquid fuels like methanol, ethanol, hydrogen, and bio-diesel as well.[181]

The second step is to convert biofuel into electricity. Most biopower today is produced in direct combustion gas turbines, but it can also be used in combined cycle turbines, diesel engines, or serve as a substitute in existing coal-fired burners.[182]

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[179] See California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, 2003. Table 1: Levelized Costs by Technology, p 3.

[180] See NREL-*PTED,* p3; NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-2, “Generating resources and technologies with moderate potential,” p. 5-9; and Alexander E. Farrell, *et al*., “Ethanol Can Contribute to Energy and Environmental Goals,” *Science,* Vol. 311, January 27, 2006.

[181] NREL-*PTED*, p3.

[182] Ibid.

Load service function: Biopower serves as baseload power supply. Direct combustion and gasification biopower generation plants have a capacity factor of about 80.0 percent.[183]

Time to construct: Biomass electric generation plants typically require four years for construction.[184]

Cost to construct: The overnight cost for a biomass electric plant is in the range of $1,759/kW.[185]

Fuel costs: The cost of fuel, or feed cost, for both direct combustion and gasification systems is $694.44/kW, and $202.78/kW for co-fired systems, according to NREL.[186] The cost of biofuel varies from about $0.174/MMBtu for landfill gas, to $2.78/MMBtu for agricultural field residue, to up to $5.52/MMBtu for logging residue.[187] Assuming a heat rate of 8,911 MMBtu/kWh, the cost of fuel per kWh of generation varies from $0.0016 ($1.55/MWh) to $0.49 ($49.19/MWh).[188]

Dependability of fuel supply: The supply of biomass is highly dependable, drawing on a waste products and agricultural crops.

Dependability of the plant: Direct combustion and gasification biopower generation plants have a capacity factor of about 80.0 percent.[189] And according to the NPCC, both wood residue and animal manure biogas electric generation plants have an availability factor of 90%. Landfill gas facilities have an availability factor of about 80%.[190]

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[183] Ibid., p. 9.

[184] EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38.

[185] Ibid.

[186] NREL-*PTED,* p. 9. The numbers for co-fired systems represent only the biofuel portion of capital, operating, and feed cost.

[187] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-3, “Estimated biofuel supply and cost,”p. 5-10.

[188] See EIA, *Assumptions to the Annual Energy Outlook, 2006*. Table 38.

[189] See NREL-*PTED,* p. 9.

[190] See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-4, “Generating resource planning assumptions,” p. 5-26.

Maturity of technology: Biopower is an immature technology.

4. Geothermal power

Overview: Geothermal energy plants tap underground reservoirs of hot water and steam that can be used for heat, electric generation, or both (i.e., CHP). Water pumped into hot dry rocks, found just below the earth's surface, can also be used to produce electricity.[191] There are three types of geothermal energy plants in use today, dry steam, flash steam, and binary-cycle. Dry steam plants use the earth's thermal energy to spin turbines directly. Flash steam plants pump hot high pressure water into low pressure tanks instantly creating steam which is then used to spin turbine blades to generate electricity. In binary-cycle plants, geothermal steam is used to heat a secondary fluid—one that has a much lower boiling point than water—causing it to vaporize. The vapor is then used to drive turbines. Cumulative geothermal installed capacity in the U.S. ranged from 2,020 to 2,252 MW in 2003.[192]

Load service function: Geothermal plants usually operate as baseload plants.[193] The capacity factors for flash steam and binary-cycle geothermal energy are approximately 93 percent; the capacity factor for hot dry rock systems is around 82 percent.[194]

Time to construct: Geothermal plants have a four year construction time.[195]

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[191] See Australian Department of the Environment and Heritage, Greenhouse Office, "Hot Dry Rock Geothermal Reservoir Development." Document available at: http://www.greenhouse.gov.au/renewable/recp/hotdryrock/two.html. Water is injected through a borehole, permeates the hot rock (which can reach 250 degrees C), and becomes superheated. The superheated water then returns to the surface where it is used to power conventional steam turbines.

[192] See NREL-*PTED*, p.1; EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003), 2004, Table 8.11a; International Geothermal Association at http://iga.igg.cnr.it/index.php; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-15 and 5-16.

[193] See NREL-*PTED,* p11; and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-2, "Generating resources and technologies with moderate potential," p. 5-2; and California Energy Commission, *Comparative Cost of California Central Station Electricity Generation Technologies*, June 6, 2003, Table 1, "Levelized Cost by Technology," 2003, p 3.

[194] NREL-*PTED,* p18.

[195] EIA, *Assumptions for the Annual Energy Outlook 2006,* Table 38, "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies," p 73.

Cost to construct: The overnight cost of a geothermal generation plant is $2,227.10/kW.[196]

Operational life: The typical operational lifetime of a geothermal electric generation plant is 30 years.[197]

Fuel costs: Geothermal units do not have fuel costs since they rely on the heat of the earth.

Dependability of fuel supply: Sources of geothermal power are very dependable since they rely on heat generated by the earth.

Dependability of the plant: Flash steam geothermal electricity plants have an availability factor of 92%.[198]

Maturity of technology: Geothermal generation technology is very mature. The world's first geothermal CHP application was built in Idaho in 1892.[199]

5. Ocean current and barrage generation

Overview: There are several different technologies used to harness the power of the ocean. This section presents an overview of the two most prominent technologies, barrage-type and ocean current. A barrage-type generator is, essentially, a large underwater dam that traps water during high tide and releases it through conventional turbines to produce electricity during the ebb, much like land-based generation dams. Ocean current technology is further divided into two subcategories, depending on the orientation of the generator's driveshaft. In *vertical-axis turbines*, also known as Davis Hydro turbines, tidal currents flow through vertically mounted rotating hydrofoils connected to a rotating shaft. Ocean currents push through the hydrofoils, applying torque, and turn the drive shaft connected to a generator housed just above sea level.[200]

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196 Ibid.

197 See California Energy Commission, *Comparative cost of California Central Station Electricity Generation Technologies*," June 6, 2003, Table 1, "Levelized Costs by Technology," p 3.

198 See NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, Table 5-4, "Generating resource planning assumptions," p. 5-26.

199 See NREL-*PTED*, p 12.

200 See Micahel Masser, *Tidal Energy: A Primer*, Blue Energy Canada, Inc., Vancouver, British Columbia, Canada, 2004. Horizontal-axis turbines are relatively new

Horizontal-axis electric generation works much like an underwater wind farm. Prevailing tidal currents turn large propeller-like hydrofoils that are coupled to submerged generators.[201] Electricity is transmitted to on-shore transformers and then to the grid.

Cost to construct: Ocean current technologies are too immature to provide firm cost data. Due to high construction and dredging costs (to remove accumulated silt), barrage-type generation dams are not economically competitive with other technologies.[202]

Fuel costs: There is no fuel cost associated with barrage-type or ocean current electric generation; the kinetic energy of the ocean is free.[203]

Dependability of fuel supply: Barrage and ocean current electric generation is very dependable because it relies on naturally occurring ocean currents.

Dependability of the plant: Information about the dependability of ocean current and barrage units is limited. The La Rance tidal barrage, located in the north of France, has been in use since the mid-1960. [204]

Maturity of technology: Barrage generators have been used in Europe since the mid-1960s and are still used around the world today.[205] Horizontal-axis ocean current technology was introduced during the 1970s, but it was not installed commercially until the mid-1990s and is still experimental today.[206]

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technology. The Canadian National Research Council and Blue Energy Canada, Inc. have successfully tested five turbine prototypes in the St Lawrence Seaway.

[201] Ibid.

[202] Ibid.

[203] Ibid.

[204] See University of Strathclyde in Glasgow, *Renewables in Scotland: Tidal Power Case Studies*. Document available at: http://www.esru.strath.ac.uk/EandE/Web_sites/01-02/RE_info/tidal1.htm.

[205] See Michael Maser, *Tidal Energy: A Primer*, and NPCC, *The Fifth Northwest Electric Power and Conservation Plan*, pp. 5-21 to 5-24.

[206] See Michael Maser, *Tidal Energy: A Primer*, and http://www.itpower.co.uk/OceanEnergy.htm. The first horizontal-axis tidal wave turbine (15kW) was installed in Loch Linnhe, Scotland. As of 2003, two UK companies planned to demonstrate horizontal-axis turbines off the coast of Norway. Currently, there are

6. Fuel Cells

Overview: Fuel cells are similar to common batteries. Both have positive and negative ends, rely on chemical reaction, and produce electricity when the circuit is closed. In hydrogen fuel cells, hydrogen passes through an anode catalyst where it is split into an ion (positively charged H+) and an electron (negatively charged e-). The positive ions pass through a conductive medium (e.g., an electrolyte membrane) and then combine with oxygen flowing in through the cathode catalyst to form water as a byproduct. The separated hydrogen electrons (e-) flow along a circuit in the cathode, creating electrical current.[207]

Fuel cells are classified by the type of electrolyte used: AFC (alkaline fuel cells), PAFC (phosphoric acid fuel cells), PEMFC (proton exchange membrane fuel cells), and MCFC (molten carbonate fuel cells), and SOFC (solid oxide fuel cells). Electric output for PEMFCs and SOFCs ranges from 5 to 250 kW. PAFCs are capable of producing 200 kW, and MCFCs can produce anywhere from 250 kW to 2 MW of power. Electric efficiency for PEMFC, PACF, MCFC, and SOFCs are 32 to 40 percent, 30 to 40 percent, 35 to 45 percent, 40 to 50 percent, and 45 to 50 percent, respectively.[208]

Load service function: Fuel cells can be sized for grid-connected or customer-sited applications, but are generally too expensive to compete without subsidies.[209]

Time to construct: Lead time for fuel cell electric generation plants, according to the EIA, is 3 years.[210]

Cost to construct: The EIA estimates overnight cost for a 10 MW fuel cell generation plant to be about $4,015/kW.[211]

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seven other ocean tide generation projects and one river tide project launched by IT Power.

[207] NREL-*PTED*, p 73.

[208] See NREL-*PTED*, p75; and Anne Marie Borbely and Jan F. Kreider. *Distributed Generation: The Power Paradigm for the New Millennium*, CRC Press 2001; and Arthur D. Little, Distributed Generation Primer: Building the Factual Foundation (multi-client study), February 2000.

[209] NREL-*PTED*, p 73.

[210] See EIA, *Assumptions to the Annual Energy Outlook, 2006*, Table 38.

[211] Ibid.

Fuel supply reliability and costs: While hydrogen itself is a clean fuel, it is most commonly obtained from fossil fuels, predominantly natural gas. Emissions-free production of hydrogen is an objective of DOE's FutureGen project for a zero-emissions IGCC plant.

Maturity of technology: Fuel cells are an immature technology.

Externalities: The only byproducts of fuel cell electricity are water and heat, but currently production of hydrogen requires fossil fuels.[212]

[212] NREL-*PTED*, p 73.

IV. The interaction of old and new generation technologies in planning decisions: the role of portfolio analysis

A. Introduction

This section introduces a conceptual framework for state commissions and other decision-makers to apply the information on individual generation technologies for making socially desirable decisions. These decisions reflect the objectives underlying generation planning subject to economic, environmental, political and public acceptability, and other constraints. Comprehending the nature and major characteristics of individual generation technologies is a first step in planning. Parts II and III of this report provide information useful in achieving that comprehension. The second step involves evaluating each of these technologies in the context of a power system consisting of existing generation facilities and customers with specific demand characteristics. Carrying out the second step requires a framework that blends the information on new and existing generation technologies to derive a desirable planning outcome.

From the perspective of the decision-maker, a framework for integrating optimally new and existing generation technologies on a power system demands more than information about the characteristics of individual technologies. It also requires factors such as: (1) specification of the objectives underlying generation planning, (2) the weights imputed for each objective (e.g., the importance of achieving the lowest cost for electricity relative to improving environmental quality), and (3) the tradeoffs between conflicting objectives (e.g., the dollar cost in achieving a higher reliability level). The collection of information on individual generation technologies combined with the application of an analytical framework can help identify and quantify the consequences of alternative ways for trading off alternative objectives.

B. A paradigm for generation planning: the portfolio approach

1. Background on the portfolio approach

A framework well suited to conceptualize the optimal interaction of both old and new generation technologies on a power system is the portfolio approach (PA). PA, originally developed for financial assets, offers several perspectives on the economics of merging different physical assets such as generating facilities into a group of assets or a portfolio.[213] PA has the feature of making decision-makers cognizant of the tradeoffs between different objectives (i.e., objectives for which advancing one compromises another). As applied to both financial and physical assets, PA emphasizes the importance of managing risk to a tolerable level for decision-makers.

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[213] See, for example, Harry Markowitz, "Portfolio Theory," *The Journal of Finance* 7 (March 1952), pp. 77-91.

PA helps decision-makers achieve efficient outcomes by minimizing the opportunity cost of a particular decision. Put another way, PA assists a decisionmaker in attaining one objective (e.g., acceptable level of fuel price risk) with minimum impediment of other objectives (e.g., total fuel cost). Recognizing that no single generation technology can advance all societal objectives, PA attempts to balance various objectives ascribed to generation planning. In other words, no generation technology emerges as an elixir for addressing all societal objectives associated with generation planning. Exploiting one or more of them inevitably will involve tradeoffs and, thus, tough choices, in advancing societal objectives

The term "societal objectives" reflects the multi-objective nature of generation planning. These objectives encompass economic, environmental and other facets of generation planning. Even within the economic category, there are sub-dimensions (e.g., least-cost, risk minimization); the same holds for environmental effects (e.g., air pollutants, nuclear waste, aesthetics). In the 1990s, natural gas was the fuel of choice for the vast majority of new generating facilities because of its attractive economic and environmental attributes, which alleviated the need for decision-makers to trade off different objectives.

Any portfolio, whether of financial assets, generation assets, or any other assets, has a risk. In this context, "risk" means the possibility that the outcome will deviate negatively from the expected outcome. Portfolio theory says that the risk of a portfolio comprised of different components relates to: (1) the inherent risks of individual assets, (2) the share of individual assets in a portfolio, and (3) the covariances between the different assets (i.e., the interdependency of different assets where events affecting one asset also affect others).[214] This paradigm accounts for the dissimilar characteristics of generation technologies by amalgamating them into a grouping of facilities that satisfies multiple objectives most efficiently.

As an illustration, let us assume that one technology has lower generation costs than a second technology, but it has higher environmental costs. Under PA, the decision-maker would gather information on the generation costs-environmental costs combinations where minimal generation costs occur at different levels of environmental costs; or equivalently, where minimal environmental costs occur at different levels of generation costs. From these various efficient combinations, the decision-maker chooses the one best corresponding with his preference for low generation costs relative to low

[214] Expressed mathematically: The expected return for a portfolio with i electricity generation technologies equals $E(R_p) = \Sigma\ w_iE(R_i)$, where $E(R_i)$ is the expected "return" from technology i and w_i is the weight of technology i held in portfolio p (e.g., the net electricity generation from i technology relative to total net generation). The risk of the portfolio is equal to its variance: $\sigma^2_p = \Sigma\Sigma w_iw_j cov(i,j)$, where cov(i,j) is the covariance between two technologies i and j. Covariance measures the diversity of the portfolio, with a lower value reflecting greater diversity and lower overall portfolio risk, assuming other things held constant.

environmental costs. For example, in the hypothetical case where the decision-maker places no value on a clean environment, he would always choose the low generation-cost technology to supply 100 percent of the electricity. At the other extreme, indifferent to the magnitude of generation costs, the decision-maker would select only the low environment-cost technology. In the real-world case where the decision-maker imputes value to both lower generation costs and lower environmental costs, he would select both technologies proportionally to the value he places on low generation costs relative to low environmental costs.

2. The rationale for the portfolio approach

The rationale for the application of PA to generation planning stems from three major sources. The first is the uncertainty and risk facing decision-makers over all facets of generation planning.[215] For example, new generation technologies share one or more of the risks pertaining to: technology design, development and siting, construction costs, future legislation and regulations, operating performance, fuel price and supply, waste and other byproducts, and dispatching of generation facilities. With uncertainty quantifiable, PA can measure the risks associated with different groupings of generation technologies. It can also measure the effect on other objectives (e.g., minimum generation costs) when risk assumes different levels.

Although managing risk constitutes an important function for risk-averse firms and society, in almost all instances minimizing risk would impose a prohibitive cost. The tradeoff involved in reducing risk through the grouping of assets requires compromising other objectives (for example, least-cost generation for a utility system). Rather than minimizing risk, the objective of most corporate entities involves selecting the risk-versus-other-objectives combination most compatible with the mission and goals of the firm in addition to preventing future states of nature that would cause them undue stress. For this reason, the term managing risk is more appropriate than minimizing risk when describing regulatory or societal goals for generation planning.

Rationalizing the use of PA can also come from the multi-objective nature of generation planning. In the case of financial assets, PA assumes an objective other than merely maximizing expected return or minimizing risk. A portfolio of different assets usually means managing risk at a cost acceptable to the decision-maker subject to the degree and nature of her risk adversity (i.e., her preference for reducing risk relative to advancing other objectives). As an example, selecting a specific generation technology, or group of technologies, may stem from its lower risks relative to other technologies,

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[215] Uncertainty differs from risk. Uncertainty exists when the decisionmaker is unable to identify future events; or can identify them but is unable to assign them probabilities. Risk assumes the availability of this information. See Andrew Stirling, "Diversity and Ignorance in Electricity Supply Investment," *Energy Policy* 22 (1994), pp. 195-216. The author argues that diversity in an environment of ignorance or a high uncertainty over the future state of affairs (i.e., where quantification of the likelihood of future events is infeasible) has inherent benefits.

even if these other technologies have lower expected generation costs. As the number and variations of objectives increase, on many occasions a portfolio of generation assets with dissimilar characteristics would be socially desirable. If at one extreme the only objective is to minimize generation cost, the socially preferred portfolio would be both easier to identify and less diversified (i.e., having assets of a similar nature) than if several objectives come into play.

A third rationale for PA lies with the heterogeneity of different generation technologies. Heterogeneity can produce benefits when the inter-asset differences are complimentary. An example of complimentary assets is oil stocks paired with airline stocks. The price of oil stocks tends to move in the opposite direction of the price of airline stocks, because airline profits drop when their operating costs rise. Thus, a portfolio with only these two stocks would have much less risk than if the portfolio consists of only one of these stocks or if the portfolio includes stocks whose prices tend to move in the same direction.

3. The goal: complementarity, not diversity

Diversity exists in many systems – biological, social, financial and physical systems, among others. A diverse system contains dissimilar elements. In a diverse system, dissimilarity produces benefits if its heterogeneous elements complement each other. Complementary traits include those that compensate for the deficiencies and shortcomings of others.[216] The goal is not diversity for diversity's sake, but diversity which produces complementarity.

Fossil fuels and renewable energy complement each other. Fossil fuel generation has lower present cost, but renewable energy insulates against environmental compliance costs incurred by the fossil fuels. An example of a non-complementary relationship is two fuels (for example, natural gas and oil) whose prices move together. With these two fuels in the same portfolio, neither one protects against adverse events associated with the other.

Complementary generation technologies in a portfolio achieve robustness. Robustness reflects a system's ability to withstand adverse events, external or internal failures. Applied to generation planning, robustness reduces the risks to customers of adverse events like equipment failures, or price spikes or shortages in particular fuels. Robustness includes flexibility -- the electricity system's ability to respond quickly to unforeseen events. Flexibility can permeate the planning and operations processes of power systems. Robustness at reasonable cost is the goal of generation planning: to

[216] Congress has recognized the relevance of diversity. EPAct 2005, adding to the PURPA a new section 111(d)(12), requires each state to consider whether each electric utility under its jurisdiction "shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to customers is generated using a diverse range of fuels and technologies, including renewable technologies."

identify those groupings of technologies that best complement each other in attaining a balanced mix of predetermined objectives.

The concept of diversity relates to PA in different ways. PA recognizes the value of diversity in achieving the specified objectives. For example, if the objective is to avoid catastrophic outcomes, then diversity can act as insurance against such results. Diverse power systems or financial portfolios tend to be more adaptable to external changes. A network with a greater variety of generation facilities would more likely have a greater capacity to adapt to large or small internal or external changes. In other words, a more diverse network is better able to respond to contingencies by avoiding seriously adverse outcomes.

The various conditions rationalizing PA also applies to diversity. With multiple objectives, an optimal decision would more likely involve a diverse portfolio to mitigate unacceptable risk. As an example, selecting a specific generation technology, or group of technologies, may stem from its lower risks relative to other technologies, even if these other technologies have lower generation costs. As the number and variations of objectives increase, generally a more diversified portfolio of generation assets would be acceptable to decision-makers. Since no single generation technology by itself best advances all objectives, a diversified portfolio of generating plants becomes more tenable.

When uncertainty inevitably becomes part of the landscape, both PA and diversity takes on added importance. Uncertainty and risk increase the benefits from selecting a mix of generation assets with dissimilar characteristics. Finally, in recognizing benefits from a grouping of heterogeneous assets in a portfolio, PA explicitly places a value on diversity. PA suggests that an optimal outcome oftentimes involves the blending of assets with dissimilar and complementary characteristics. Overall, PA can assist decision-makers in examining the merits of a diverse portfolio in mitigating risks and advancing other societal objectives.

PA recognizes that while diversity can produce good results, it also can lead to adverse effects when not implemented carefully. By definition, optimal diversity maximizes net societal benefits, with departures from optimality resulting in a net cost. The cost of excessive diversity – or diversity for the sake of diversity -- can derive from the following sources: (1) lost scale economies resulting from the reduced operation of technologies (e.g., baseload plants) that require intensive use to exploit their full benefits on a power system; (2) transaction costs stemming from the acquisition and validity of information for generation technologies unfamiliar to the utility; and (3) additional capital and operating costs associated with configuring generating units to make them more flexible (for example, to handle alternative fuel sources or to interact complementarily with other generating plants). A co-author of this report previously concluded that fuel and technology diversity, considered alone, is not necessarily desirable. The desirability of diversity hinges on its ability to advance specified societal objectives, collectively, taking into account the various constraints and risks associated with those objectives. He concluded that decision-makers should not bind themselves to a pre-specified diversity target.[217]

4. Implications of PA for generation planning

A generation portfolio aggregates the old and the new. A decision about new generation therefore must take into account existing generation. The decision-maker must ask not only "Do I like this proposed generation technology?" but also "Does adding this technology to my existing portfolio help achieve my multiple objectives?" Generation planning requires consideration of the interaction among possible new options with existing generation. Decision-makers should consider whether current procedures accommodate such analysis.[218]

In the typical generation approval proceeding, the proponent proffers a single generation option in detail. Less detail is available on how the proposed plant, and the rejected plants, would interact with existing generation. A selection process that focuses the decision-maker on a single option does not fit well with PA considerations. Evaluation of an option on a stand-alone basis ignores the benefits and costs of the option – and other options -- on the power system network. In sum, evaluation of different generating technologies requires evaluation of alternative resource portfolios.

The application of PA to generation planning explicitly accounts for the risk effects of different technologies on a power system. Although a particular technology can have high risk on a stand-alone basis, when combined with existing plants the risk can decrease and become societally desirable. PA also helps decision-makers to conceptualize the tradeoffs between different planning objectives. It goes further by quantifying the benefits and costs of advancing certain objectives at the expense of others. PA accounts for the tradeoffs between different planning objectives by identifying the most efficient way to advance one or more objectives. For example, in moderating risk to a specified level, PA can show the preferred approach in terms of minimizing the increase in generation costs.

Some critics of PA application to physical assets – for example, generation facilities -- argue that the underlying theory is more pertinent to financial assets partially because of they can more easily be bought and sold on the open market at incremental quantities. Critics also point to the complexities of applying PA to generation technologies because of the multiple objectives. (i.e., in addition to risk and generation costs, typically decision-makers judge technologies because of their environmental,

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[217] Ken Costello, *Making the Most of Alternative Generation Technologies: A Perspective on Fuel Diversity*, NRRI Briefing Paper (05-02), March 2005.

[218] For additional insights on the applicability of portfolio theory to generation planning, see Shimon Awerbuch, "Portfolio-Based Electricity Generation Planning: Policy Implications for Renewables and Energy Security," *Mitigation and Adaptation Strategies for Global Change* 11 (2006), pp. 693-710.

safety, and reliability effect, among others). Critics also contend that the immeasurable nature of probabilities for many future events diminishes the usefulness of PA or any tool that attempts to quantify the effects of those events. PA also requires a well-defined preference function for the different objectives of generation planning, in addition to covariance coefficients (i.e., measures of the interdependencies between different technologies in response to events), both of which are difficult to quantify.[219] Even the validity of these criticisms, however, does not prevent PA from offering decision-makers a useful conceptual framework to evaluate new generation technologies.

C. Applying portfolio analysis to generation: five steps

Determining an appropriate generation portfolio requires a five-step analysis. Each step involves the regulator's judgment:

1. *Identify the objectives of generation planning.* These objectives can include reasonable generation costs, a clean environment, high power-system reliability and moderate price risk; the specification of objectives affects the ranking and selection of new technologies.

2. Determine the relative weights of the individual objectives. For example, the regulator values low cost, and she values low environmental impact. By assigning weights to these desires, preferably through quantification (to allow for apples-to-apples comparisons), she can make the tradeoffs -- the opportunity costs - - explicit. This explicitness aids rational decisionmaking in the achievement of societal goals.

3. *Identify inherent characteristics of individual technologies.* For example, natural gas technologies have high price risk relative to other technologies while nuclear power has high construction cost and public-acceptability risks; information on individual technologies provides critical, but not sufficient, input into the generation planning process and the determination of socially optimal decisions.

4. *Recognize and consider "tradeoff" effects.* An example is the added generation cost associated with higher environmental quality or lower price risk. With no single technology advancing all societal objectives by itself, a balanced grouping of different technologies can best satisfy overall generation-planning goals; moving toward one or more technologies inevitably will involve tradeoffs and, thus, tough choices for decision-makers, in advancing societal objectives.

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[219] See Nigel Lucas *et al*., "Diversity and Ignorance in Electricity Supply Investment: a Reply to Andrew Stirling," *Energy Policy* 23, no. 1 (1995), pp. 5-7; and Frank C. Graves, "Response to Synapse Report," unpublished paper, August 2006, available at: http://www.brattle.com/_documents/Publications/ArticleReport2408.pdf.

5. *Create efficient portfolios.* An efficient portfolio advances the desired objectives at minimum cost. The decisionmaker has multiple objectives. Some of these objectives are in opposition to each other (e.g., price level vs. price predictability). She seeks to minimize the tradeoffs among opposing objectives so that the achievement of one occurs at minimum cost to another. In regard to financial assets, PA derives an "efficient frontier" that maps out the set of portfolios with the maximum expected return for every given level of risk, or the minimum risk for every level of expected return; portfolios along the efficient frontier are preferable to all other portfolios; portfolios off the efficient frontier are ether infeasible or inefficient.

The inputs to the efficient frontier are data: data on costs, reliability, and other possible outcomes, negative and positive. The regulator then has to choose among the options, options which equal each other in efficiency but which differ from each other in terms of the tradeoffs and uncertainties involved. To make this choice, the regulator cannot demand certainty because certainty comes at too high a price. Nor can the regulator defer the decision until certainty arrives, because certainty will not arrive. The regulator must use judgment – the judgment being, which point on the frontier best advances the public interest.

V. Conclusion

This report has discussed two steps necessary to ensuring an appropriate mix of generation: develop an understanding of different generation technologies and how those technologies can fit together in a portfolio. A regulator should also examine the possibility of using demand-side responses or providing additional investment in energy efficiency as a lower-cost alternative to additional generation capacity.

A state commission is responsible for advancing the public's need for affordable, available, and environmentally-acceptable sources of electricity. The regulator should determine what authorities his or her commission has over generation resource decisions and what new authorities the commission needs to fulfill its responsibilities. Regulators should also determine how to participate effectively in any regional and national planning processes.

A regulator should understand that a state commission's decision on future generation is shaped by the state and region's current mixture of generation. There are infrastructure costs and benefits from currently predominant technologies. Existing pipelines, railways, and transmission corridors all exert influence on the feasibility of alternative technologies. Currently predominant technologies also offer a familiarity to both regulators and utilities, but regulators should inform themselves about other alternatives.

In addition, commissions should recognize that the condition of a state or region's retail or wholesale market and the markets' ability to send clear signals to power producers also determines what technologies will be feasible. Ultimately, new plants are only built unless prices provide a return on investment to cover the cost of building and running the plant.

This report offers an approach for state commissioners to employ for evaluating different generation technologies. Technological considerations are only one factor among many in determining the proper mix of generation, however. In short, the judgment of decision-makers is critical when commissions make choices about generation choices. This judgment revolves around decision-makers' perceptions of the public policy objectives attached to electricity generation, their assessment of the possible risks and rewards offered by the technologies, and the decision-makers' comfort with those risks and rewards.

Appendix A

State renewable portfolio standards:

The percentage or amount of generation that must come from renewable sources by a given target year.

State	Year Enacted	Year Revised	Initial target	Final target
Arizona	2001	2006	0.2% by 2001	15% by 2025
California	2002	2005	13% by 2003	33% by 2020
Colorado	2004		3% by 2007	10% by 2015
Connecticut	1999	2003	4% by 2004	10% by 2010
Delaware	2005		1% by 2007	10% by 2019
District of Columbia	2005		4% by 2007	11% by 2022
Hawaii	2004		7% by 2003	20% by 2020
Illinois (voluntary)	2005		2% by 2007	8% by 2013
Iowa	1991		None	105 MW
Maine	1999		None	30% by 2000
Maryland	2004		3.5% by 2006	7.5% by 2019
Massachusetts	1997		1% new by 2003	4% new by 2009
Minnesota	1997		1,125 MW by 2010	1,250 MW by 2013
Montana	2005		5% by 2008	15% by 2015
Nevada	1997	2005	6% by 2005	20% by 2015
New Jersey	2001	2004	6.5% by 2008	20% by 2020
New Mexico	2002	2004	5% by 2006	10% by 2011
New York	2004		None	25% by 2013
Pennsylvania	2004		1.5% by 2007	18% by 2020
Rhode Island	2004		3% by 2007	16% by 2020
Texas	1999	2005	2,280 MW by 2007	5,880 MW by 2015
Vermont	2005		None	Load growth by 2012
Wisconsin	1999	2006	None	10% by 2015

Source: Barry R. Rabe, "Race to the Top: The Expanding Role of U.S. State Renewable Portfolio Standards," Pew Center on Global Climate Change, June 2006, p. 4.

Appendix B

Carbon dioxide capture and storage

Electricity generation results in multiple externalities. The technology-specific sections of Part III of this report describe the most salient externalities for each technology. This appendix addresses in more detail the emission of carbon dioxide (CO_2), which is produced by all of the fossil-fueled plants. The likelihood of future regulation of CO2 has reached a level warranting state commissions' attention. National, regional, or state-level policies to lower emissions of CO_2will affect comparisons of generation technologies.[220]

CO_2 capture and storage (CCS) is one means of limiting the amount of CO_2 released into the atmosphere, namely by removing CO_2 from the flue gas of fossil fuel-based electricity generation plants. CCS consists of the separation of CO_2 from a plant's emissions, compression of the CO_2, transport to a storage location, and long-term sequestration from the atmosphere in subsurface geologic formations.[221]

The cost of a full CCS system for a new fossil fuel-based generation plant depends on a number of factors, including the characteristics of the power plant, the capture system, and the storage site; the amount of CO_2; and the transport distance. Capture (including compression) of CO_2 is the largest cost component.[222] There is little experience using CSS as an integrated system, so the data reported here about the cost of CSS are general estimates. Using data from multiple countries, the International Panel on Climate Change estimates that using CCS with a new plant increases the cost of producing electricity in comparison to a similar plant without a CCS system.[223] The costs are reported in Table 2 below.

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[220] The 110th Congress is considering legislation to limit greenhouse gas emissions. Currently there are greenhouse gas measures in place in the Northeast (the Regional Greenhouse Gas Initiative; see www.rggi.org) and California (The Global Warming Solutions Act of 2006).

[221] Intergovernmental Panel on Climate Change (IPCC), *Special Report on Carbon Dioxide Capture and Storage*, IPCC, Geneva, Switzerland, 2005. Report available at: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/IPCCSpecialReportonCarbondioxideCaptureandStorage.htm.

[222] Ibid., p. 9.

[223] Ibid., Table TS.10, p. 43. As the IPCC report indicates at footnote 5 (p. 27), "The cost of electricity production should not be confused with the price of electricity to customers." The production cost in the report excludes the capital cost of the generating unit. If the cost of CCS is applied to the total cost of electricity (capital plus operating cost) the percentage increase in cost from the use of CCS is lower than the figures reproduced in this appendix.

Table 2

Increase in cost of producing electricity with carbon capture and storage for selective technologies

Technology	**Pulverized coal**	**Natural gas combined cycle**	**Integrated gasification combined cycle**
Cost of producing electricity without CSS ($/kWh)	0.043 – 0.052	0.031 – 0.050	0.041 – 0.061
Increase in cost of producing electricity with CCS ($/kWh)	0.019 – 0.047	0.012 – 0.029	0.010 – 0.032
Percentage increase in cost of producing electricity with CCS	43 – 91%	37 – 85%	14 – 53%

Plant emissions can be lowered to nearly zero by employing CCS with hydrogen as the power plant fuel. Such a plant is technically feasible now, but no hydrogen-fueled combustion turbine is commercially available at present.[224] The FutureGen initiative is a partnership between DOE and private companies to develop a zero emissions IGCC plant with hydrogen fueled combustion.[225]

[224] Charles, R., *et al.*, *Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016*, Sargent & Lundy and Synapse Energy Economics report prepared for Southern California Edison, pp. 2-25, 2006.

[225] See http://www.fossil.energy.gov/programs/powersystems/futuregen/.

Appendix C

List of acronyms

AFC	Alkaline fuel cell
Btu	British thermal unit
BWR	Boiling water reactors
CAES	Compressed air energy storage
CAIR	Clean Air Interstate Rules
CAMR	Clean Air Mercury Rules
CCGT	Combined cycle gas turbine
CGT	Combustion gas turbine
CCS	Carbon dioxide capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CSP	Concentrated solar power
CWIP	Construction work in progress
DOE	United States Department of Energy
EIA	Energy Information Administration, United States Department of Energy
EIS	Environmental impact statement
ELCC	Effective load-carrying capacity
EPAct	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulphurization
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated resource planning
ISO	Independent system operator
kW	Kilowatt
kWh	Kilowatt-hour
LOLP	Loss of load probability
Mcf	Million cubic feet
MCFC	Molten carbonate fuel cells

MMBtu	Million British thermal units
MW	Megawatt
NETL	National Energy Technology Laboratory
NO_x	Nitrogen oxide
NPCC	Northwest Power and Conservation Council
NPCC	Northwest Power Planning Council
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
PA	Portfolio analysis
PAFC	Phosphoric acid fuel cells
PC	Pulverized coal
PEMFC	Proton exchange membrane fuel cells
PHS	Pumped hydroelectric storage
Psi	Pounds per square inch
PUC	Public utility commission
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
PWR	Pressurized water reactor
RTO	Regional transmission organization
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SOFC	Solid oxide fuel cells
TVA	Tennessee Valley Authority
VOC	Volatile organic compounds

Appendix D

Generation technology diagrams

Figure 1: Combined cycle gas turbine
(Source: DOE, Office of Energy Efficiency and Renewable Energy)

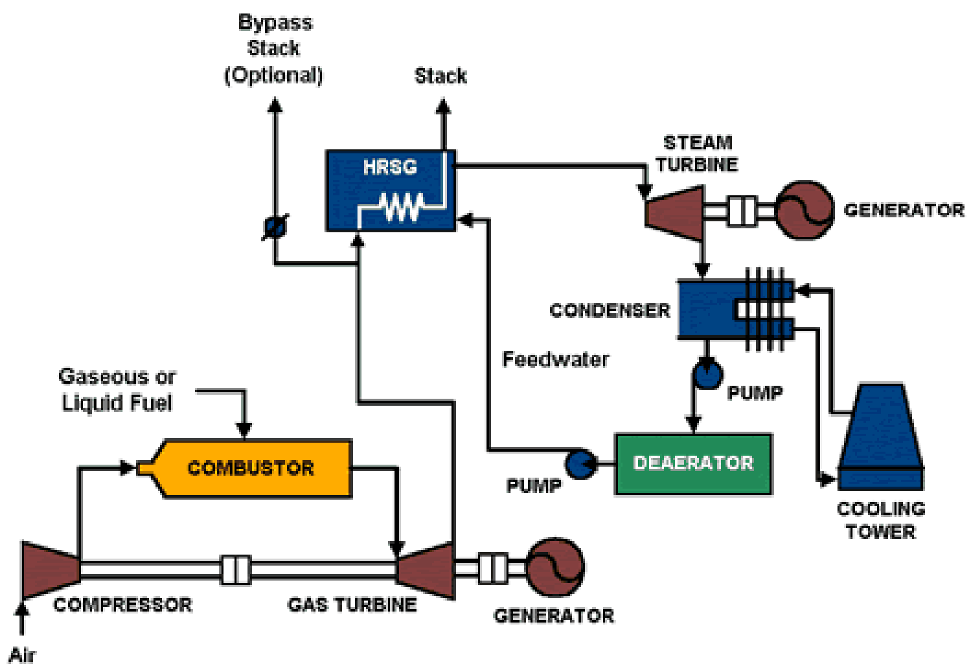


Figure 2: Combustion gas turbine
(Source: Tennessee Valley Authority)

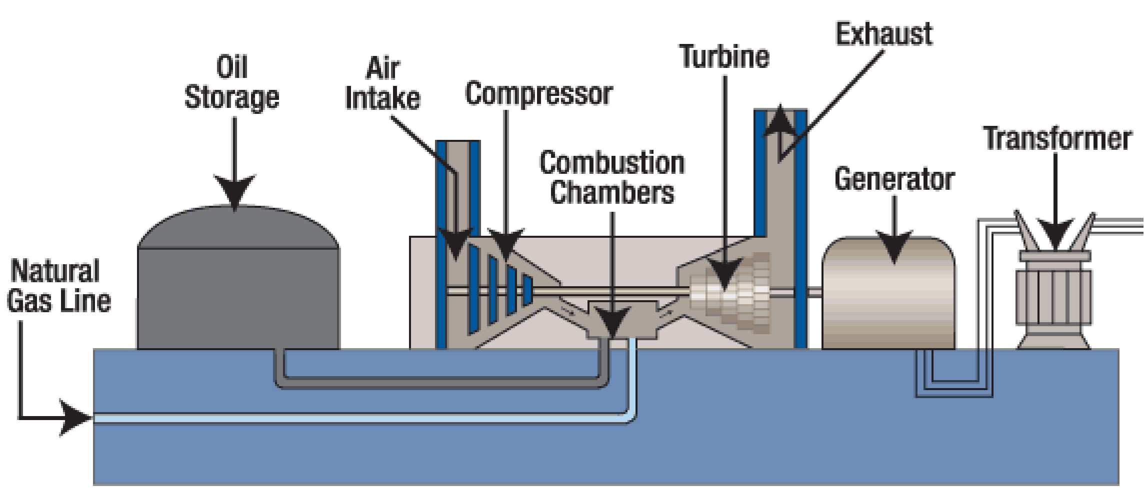


Figure 3: Pulverized coal generation
(Source: Tennessee Valley Authority)

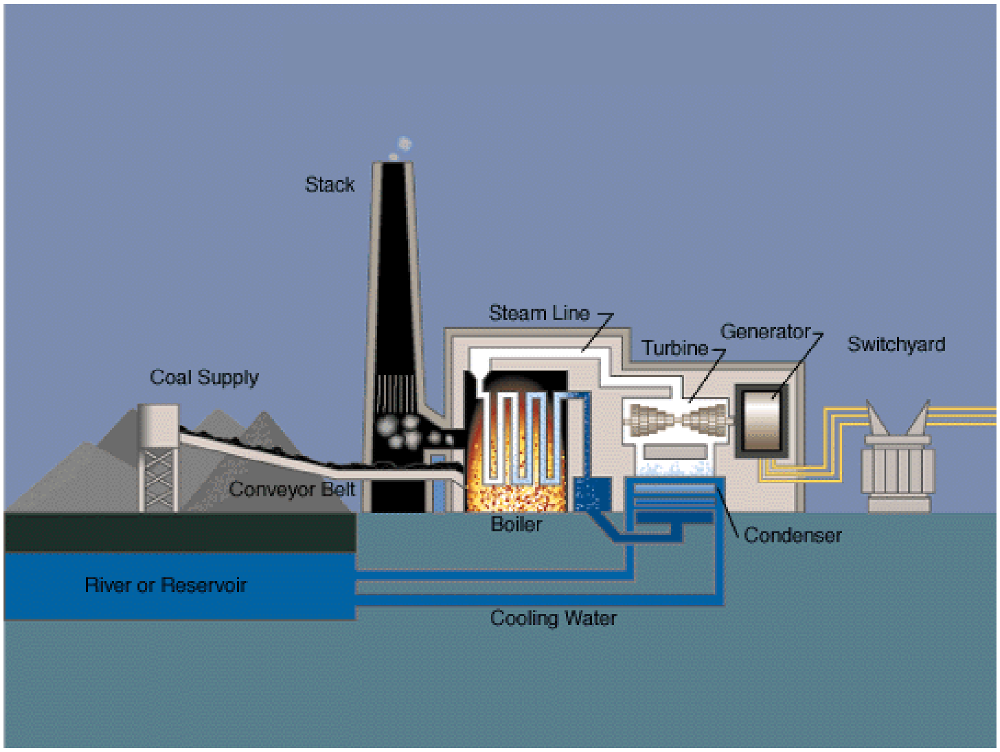


Figure 4: Fluidized bed combustion
(Source: DOE, National Energy Technology Laboratory)

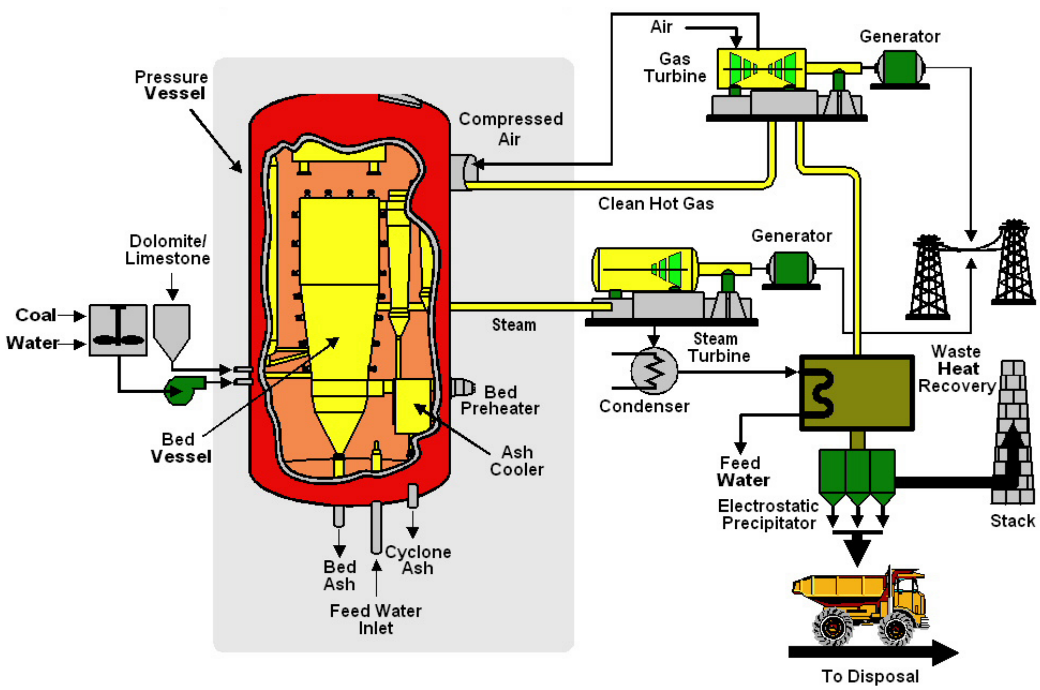


Figure 5: Integrated gasification combined cycle (IGCC) generation
(Source: DOE, National Energy Technology Laboratory)

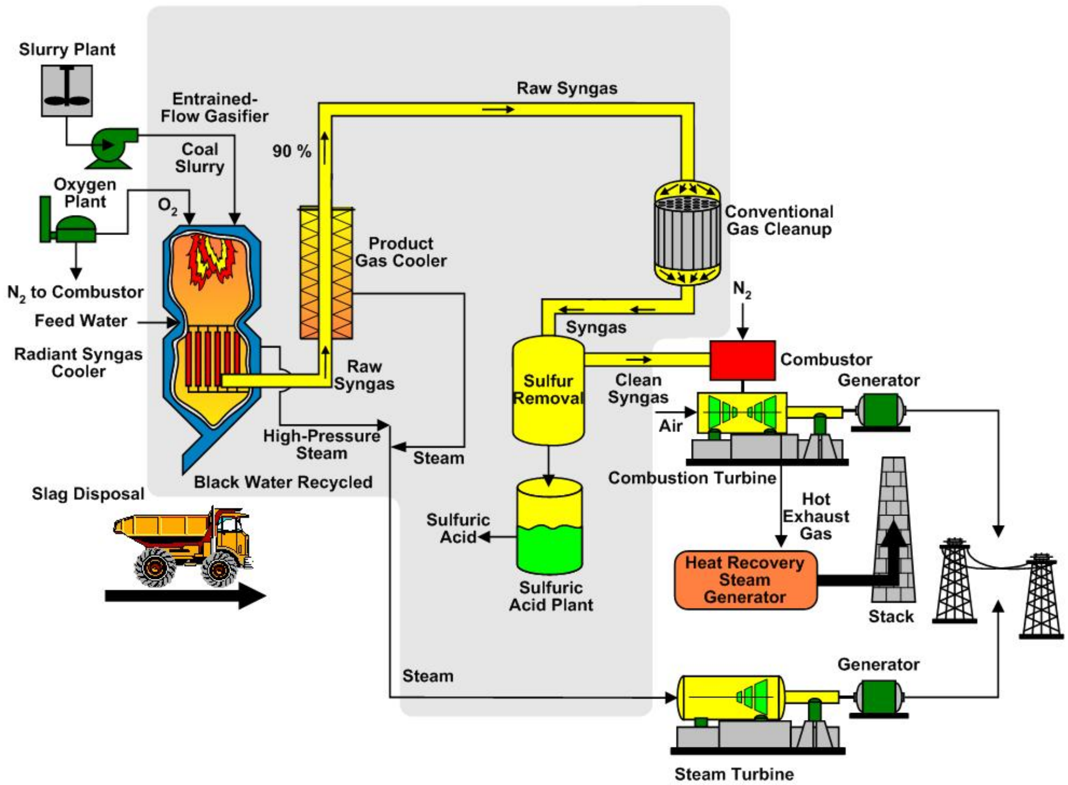


Figure 6: Pressurized water nuclear reactor
(Source: Tennessee Valley Authority)

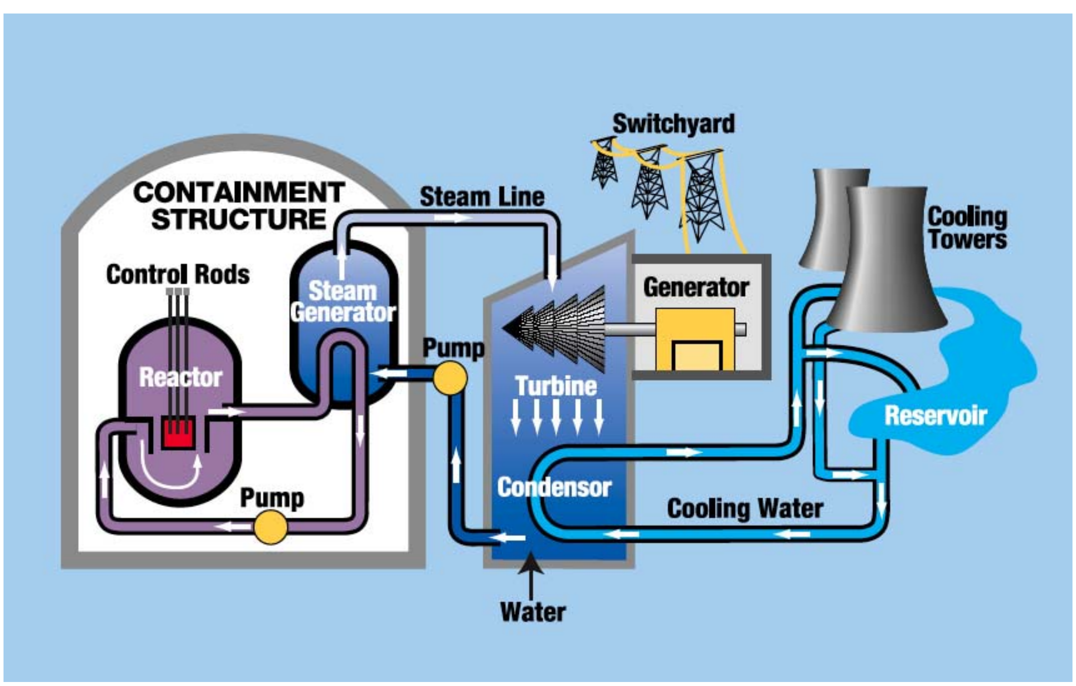


Figure 7: Wind turbine
(Source: DOE, National Renewable Energy Laboratory)

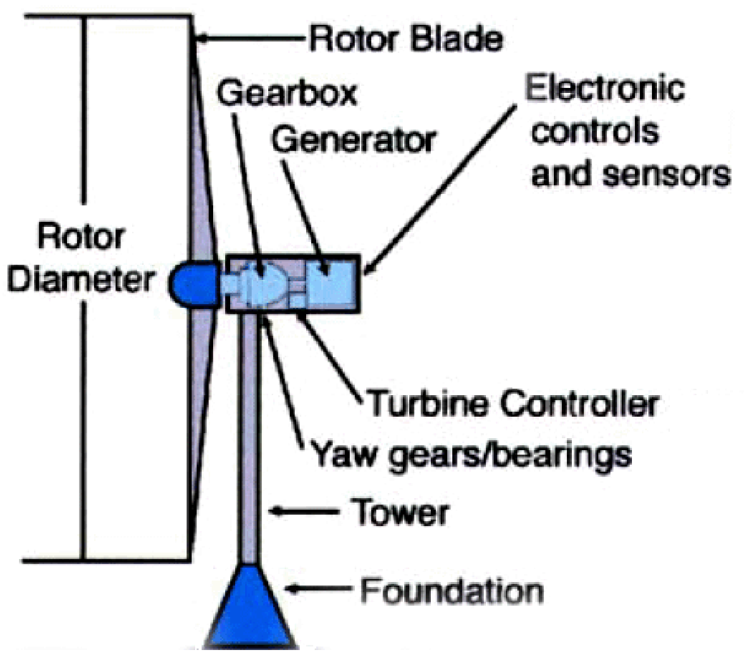


Figure 8: Pumped-storage hydropower
(Source: Tennessee Valley Authority)

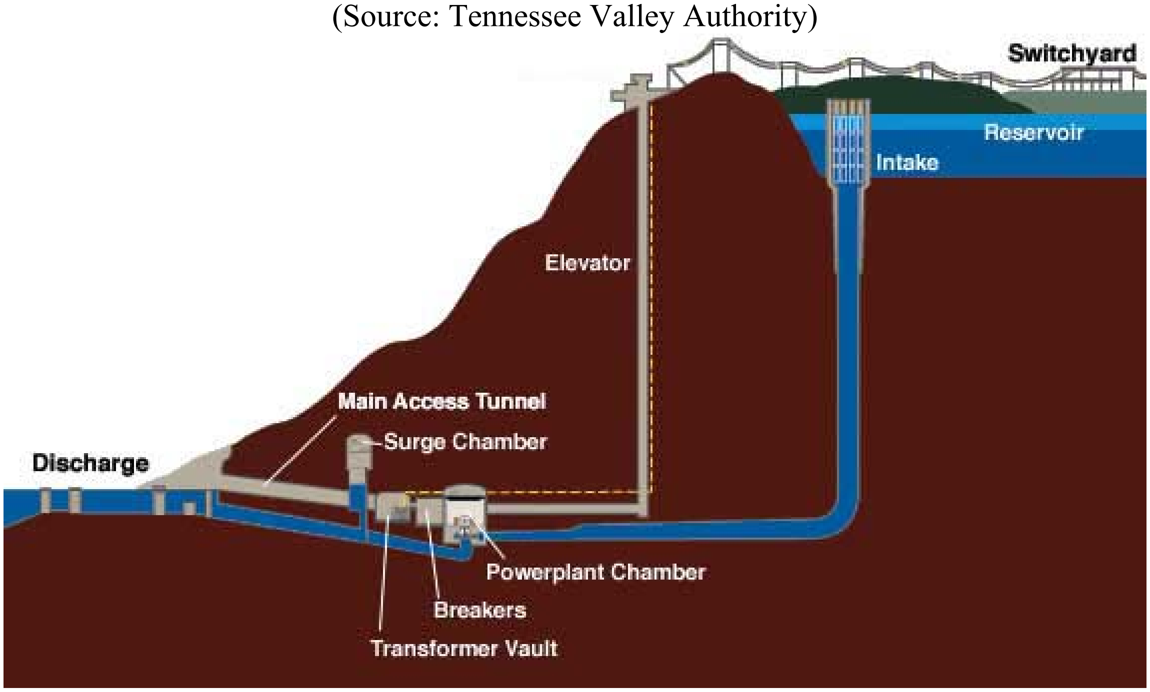


Figure 9: Photovoltaic power
(Source: DOE, National Renewable Energy Laboratory)

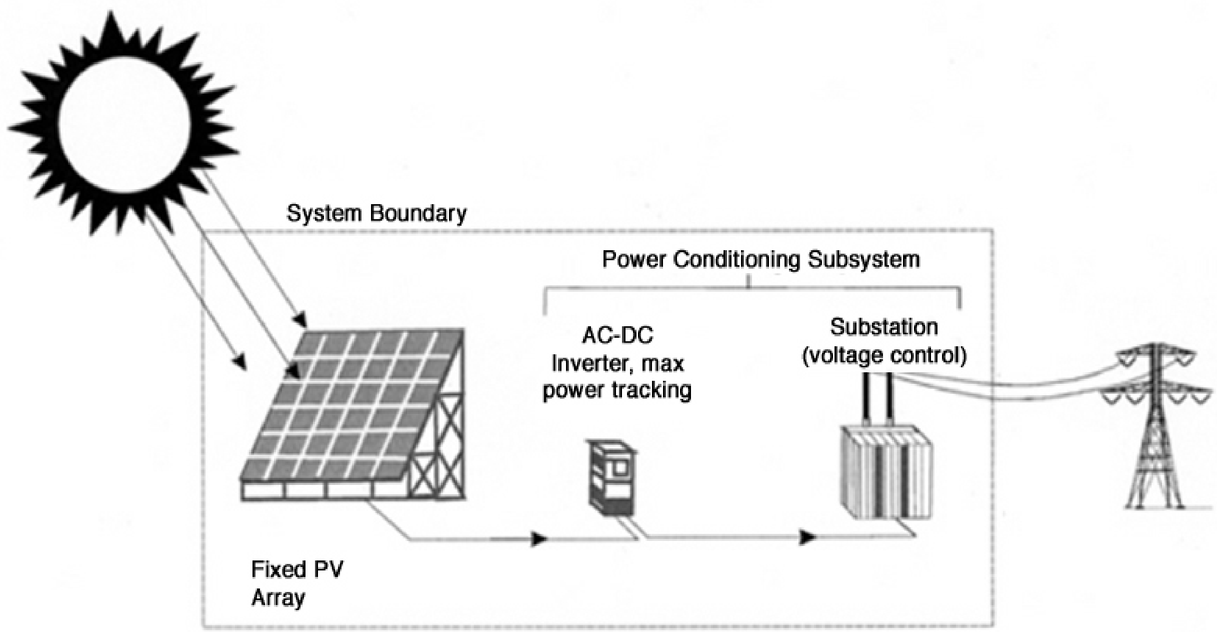


Figure 10: Concentrated solar power
(Source: DOE, National Renewable Energy Laboratory)

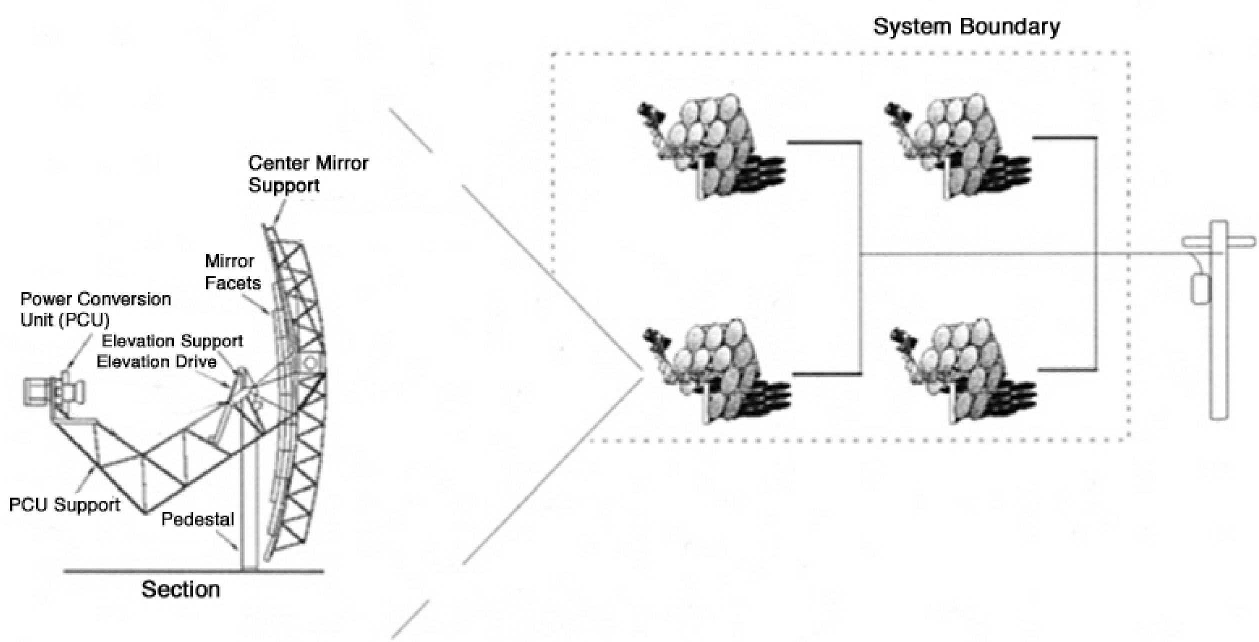


Figure 11: Biomass power
(Source: DOE, Office of Energy Efficiency and Renewable Energy)

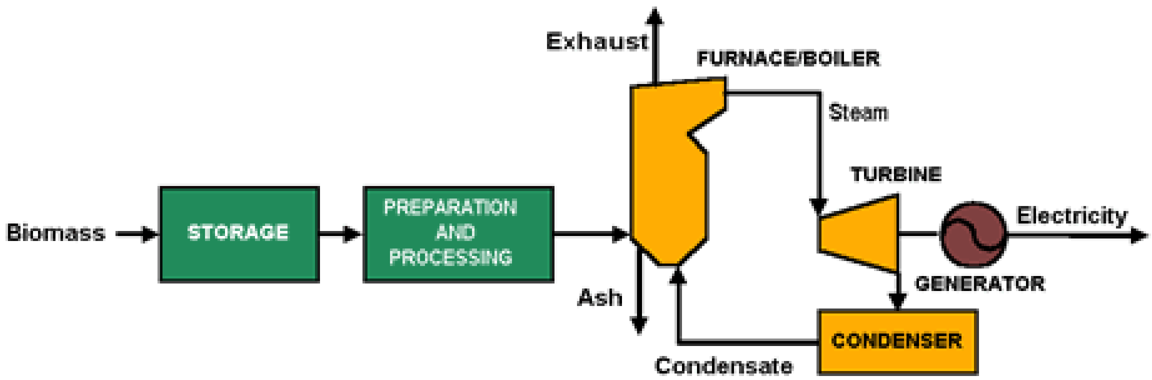


Figure 12: Geothermal power (binary-cycle)
(Source: DOE, Office of Energy Efficiency and Renewable Energy)

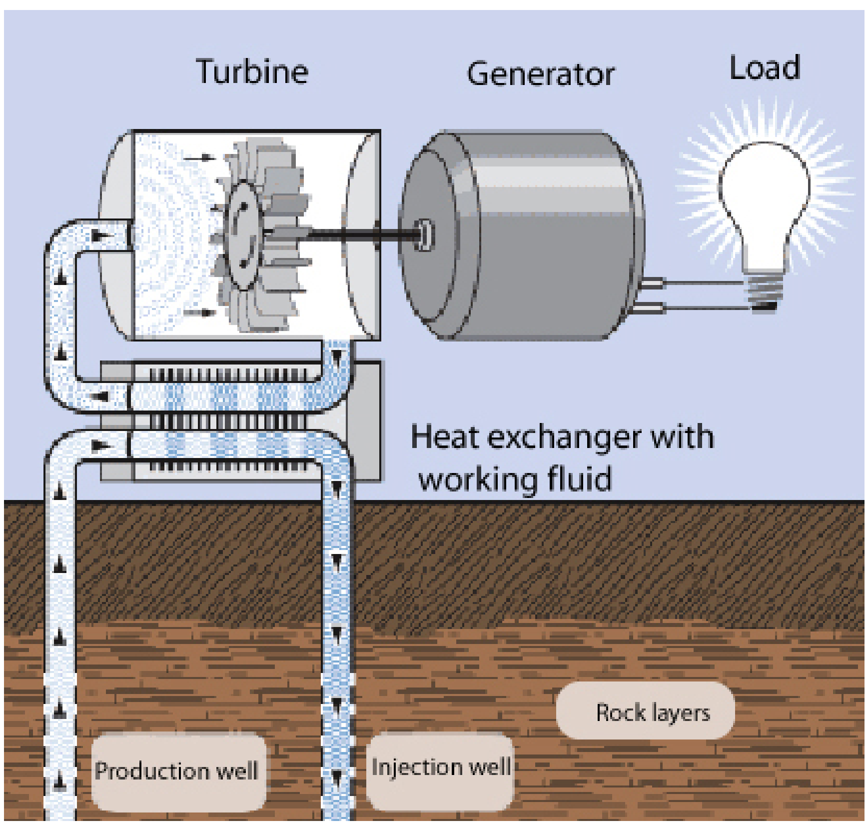


Figure 13: Tidal turbine
(Source: DOE, Energy Information Agency)

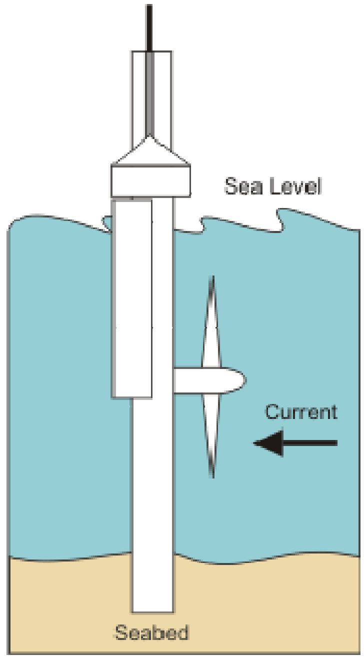
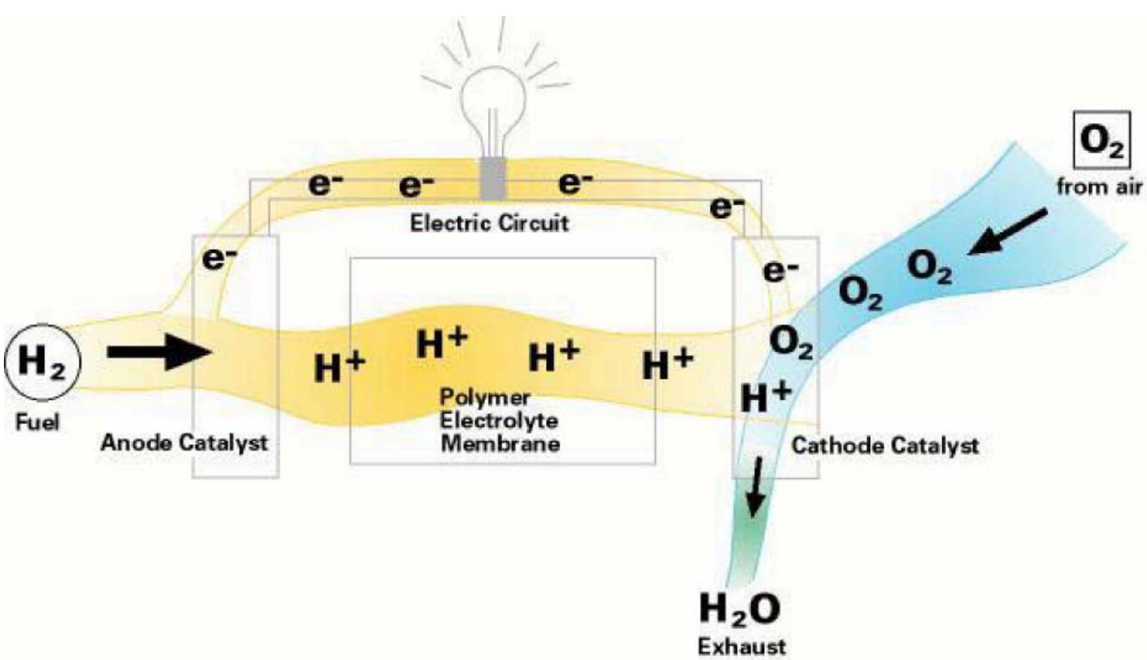


Figure 14: Fuel cell
(Source: DOE, National Renewable Energy Laboratory)



Appendix E: Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Alabama	Combined cycle	Natural gas	55	8,699.8	7,857.4	3	4	7
		Total	55	8,699.8	7,857.4	3	4	7
	Combustion (gas) turbine	Distillate fuel oil	1	21.2	16.0	36	36	36
		Natural gas	29	2,400.0	2,172.6	7	10	34
		Total	30	2,421.2	2,188.6	7	11	34
	Hydraulic turbine	Water	101	3,238.9	3,199.0	40	56	77
		Total	101	3,238.9	3,199.0	40	56	77
	Internal combustion engine	Distillate fuel oil	13	26.6	26.6	6	8	9
		Total	13	26.6	26.6	6	8	9
	Steam turbine	Biomass	5	192.4	181.5	24	27	28
		Coal	39	12,359.1	11,284.9	35	46	52
		Natural gas	2	49.0	38.0	21	30	39
		Nuclear material	4	4,118.4	3,943.0	27	29	30
		Other coal	1	269.2	255.0	40	40	40
		Other gas	3	28.8	19.8	9	48	48
		Total	54	17,016.9	15,722.1	28	41	51
	Total	Biomass	5	192.4	181.5	24	27	28
		Coal	39	12,359.1	11,284.9	35	46	52
		Distillate fuel oil	14	47.8	42.6	6	8	10
		Natural gas	86	11,148.8	10,068.0	4	6	11
		Nuclear material	4	4,118.4	3,943.0	27	29	30
		Other coal	1	269.2	255.0	40	40	40
		Other gas	3	28.8	19.8	9	48	48
		Water	101	3,238.9	3,199.0	40	56	77
		Total	**253**	**31,403.4**	**28,993.7**	**8**	**36**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Alaska	Combined cycle	Natural gas	6	388.7	329.4	27	28	30
		Total	6	388.7	329.4	27	28	30
	Combustion (gas) turbine	Distillate fuel oil	9	241.7	212.2	23	29	30
		Natural gas	22	490.2	460.1	22	30	38
		Total	31	731.9	672.3	22	29	35
	Hydraulic turbine	Water	37	324.2	326.6	22	33	52
		Total	37	324.2	326.6	22	33	52
	Internal combustion engine	Distillate fuel oil	156	229.6	220.1	8	18	26
		Natural gas	2	3.0	3.0	12	12	12
		Total	158	232.6	223.1	8	17	26
	Steam turbine	Coal	15	108.5	104.9	31	42	54
		Total	15	108.5	104.9	31	42	54
	Total	Coal	15	108.5	104.9	31	42	54
		Distillate fuel oil	165	471.3	432.3	9	18	27
		Natural gas	30	881.9	792.5	22	28	35
		Water	37	324.2	326.6	22	33	52
		Total	**247**	**1,785.9**	**1,656.3**	**12**	**22**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Arizona	Combined cycle	Natural gas	64	11,635.2	9,561.3	3	4	5
		Total	64	11,635.2	9,561.3	3	4	5
	Combustion (gas) turbine	Distillate fuel oil	4	127.1	108.0	28	30	33
		Natural gas	39	1,795.8	1,635.8	4	32	34
		Total	43	1,922.9	1,743.8	4	32	34
	Hydraulic turbine	Water	34	2,718.0	2,720.4	41	55	67
		Total	34	2,718.0	2,720.4	41	55	67
	Internal combustion engine	Distillate fuel oil	1	1.5	1.5	16	16	16
		Natural gas	1	1.6	1.6	6	6	6
		Other gas	5	5.0	4.0	5	5	5
		Total	7	8.1	7.1	5	5	6
	Photovoltaic	Solar	7	9.0	9.0	4	5	8
		Total	7	9.0	9.0	4	5	8
	Pumped storage hydraulic turbine	Water	6	194.1	216.0	13	13	34
		Total	6	194.1	216.0	13	13	34
	Steam turbine	Biomass	1	3.0	2.5	2	2	2
		Coal	16	5,861.3	5,430.0	26	28	32
		Natural gas	13	1,393.5	1,285.0	46	48	51
		Nuclear material	3	4,209.3	3,875.0	18	20	20
		Total	33	11,467.1	10,592.5	26	32	46
	Total	Biomass	1	3.0	2.5	2	2	2
		Coal	16	5,861.3	5,430.0	26	28	32
		Distillate fuel oil	5	128.6	109.5	28	28	32
		Natural gas	117	14,826.1	12,483.7	3	5	33
		Nuclear material	3	4,209.3	3,875.0	18	20	20
		Other gas	5	5.0	4.0	5	5	5
		Solar	7	9.0	9.0	4	5	8
		Water	40	2,912.1	2,936.4	35	54	66
		Total	**194**	**27,954.4**	**24,850.1**	**4**	**20**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Arkansas	Combined cycle	Natural gas	30	4,667.3	4,042.0	3	4	4
		Total	30	4,667.3	4,042.0	3	4	4
	Combustion (gas) turbine	Natural gas	10	265.9	252.6	16	26	36
		Total	10	265.9	252.6	16	26	36
	Hydraulic turbine	Water	45	1,300.3	1,379.8	18	41	53
		Total	45	1,300.3	1,379.8	18	41	53
	Internal combustion engine	Distillate fuel oil	7	13.3	13.4	30	43	51
		Natural gas	3	19.2	18.0	5	5	5
		Other gas	3	1.5	1.5	23	23	23
		Total	13	34.0	32.9	15	23	43
	Pumped storage hydraulic turbine	Water	1	28.0	28.0	34	34	34
		Total	1	28.0	28.0	34	34	34
	Steam turbine	Biomass	12	366.5	294.0	15	32	44
		Coal	5	3,958.0	3,793.0	23	25	26
		Natural gas	14	2,457.5	2,359.0	40	53	56
		Nuclear material	2	1,845.0	1,834.0	26	29	32
		Total	33	8,627.0	8,280.0	26	38	52
	Total	Biomass	12	366.5	294.0	15	32	44
		Coal	5	3,958.0	3,793.0	23	25	26
		Distillate fuel oil	7	13.3	13.4	30	43	51
		Natural gas	57	7,409.9	6,671.6	4	5	36
		Nuclear material	2	1,845.0	1,834.0	26	29	32
		Other gas	3	1.5	1.5	23	23	23
		Water	46	1,328.3	1,407.8	18	41	53
		Total	**132**	**14,922.5**	**14,015.3**	**6**	**31**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
California	Combined cycle	Natural gas	171	15,910.4	13,457.3	3	12	18
		Other gas	4	35.2	28.7	4	13	20
		Total	175	15,945.6	13,486.1	3	12	18
	Combustion (gas) turbine	Distillate fuel oil	14	651.7	536.7	26	29	30
		Natural gas	221	6,623.6	6,054.2	5	18	21
		Other gas	18	248.5	203.3	7	17	19
		Other petroleum	1	15.0	14.0	35	35	35
		Total	254	7,538.8	6,808.2	5	18	22
	Geothermal binary cycle turbine	Geothermal	22	99.5	91.4	13	15	16
		Total	22	99.5	91.4	13	15	16
	Hydraulic turbine	Water	430	9,978.2	10,079.7	22	45	82
		Total	430	9,978.2	10,079.7	22	45	82
	Internal combustion engine	Distillate fuel oil	10	24.0	24.0	37	37	41
		Natural gas	84	160.7	152.7	5	15	17
		Other gas	91	116.1	107.9	7	13	21
		Total	185	300.8	284.6	6	15	21
	Other	Waste heat	1	7.5	7.5	23	23	23
		Total	1	7.5	7.5	23	23	23
	Photovoltaic	Solar	2	2.0	2.0	20	21	22
		Total	2	2.0	2.0	20	21	22
	Pumped storage hydraulic turbine	Water	30	3,352.6	3,688.4	29	38	39
		Total	30	3,352.6	3,688.4	29	38	39
	Steam turbine	Biomass	34	660.7	589.2	16	17	21
		Coal	8	415.4	366.9	17	18	24
		Geothermal	125	2,632.8	1,903.4	18	19	20
		Natural gas	67	16,641.1	16,278.6	39	43	47
		Nuclear material	4	4,577.0	4,324.0	21	22	23
		Other gas	10	144.4	115.4	16	19	70
		Other petroleum	8	190.8	167.4	16	17	20
		Solar	9	400.4	399.8	18	19	20
		Waste	3	71.6	53.0	18	18	20
		Waste heat	1	19.3	19.3	17	17	17
		Total	269	25,753.5	24,217.0	17	20	33

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
California (continued)	Wind turbine	Wind	81	2,037.6	2,023.3	9	18	21
		Total	81	2,037.6	2,023.3	9	18	21
	Total	Biomass	34	660.7	589.2	16	17	21
		Coal	8	415.4	366.9	17	18	24
		Distillate fuel oil	24	675.7	560.7	28	31	37
		Geothermal	147	2,732.3	1,994.8	17	19	20
		Natural gas	543	39,335.8	35,942.8	5	17	21
		Nuclear material	4	4,577.0	4,324.0	21	22	23
		Other gas	123	544.2	455.3	7	15	21
		Other petroleum	9	205.8	181.4	16	17	23
		Solar	11	402.4	401.8	18	20	21
		Waste	3	71.6	53.0	18	18	20
		Waste heat	2	26.8	26.8	17	20	23
		Water	460	13,330.8	13,768.1	23	42	81
		Wind	81	2,037.6	2,023.3	9	18	21
		Total	**1,449**	**65,016.1**	**60,688.1**	**15**	**20**	**37**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Colorado	Combined cycle	Natural gas	30	2,750.1	2,311.0	7	12	16
		Total	30	2,750.1	2,311.0	7	12	16
	Combustion (gas) turbine	Distillate fuel oil	2	129.4	100.0	29	29	29
		Natural gas	34	2,344.0	1,788.3	4	5	7
		Other gas	2	7.0	5.0	6	6	6
		Total	38	2,480.4	1,893.3	4	6	7
	Hydraulic turbine	Water	49	634.1	646.1	21	52	75
		Total	49	634.1	646.1	21	52	75
	Internal combustion engine	Distillate fuel oil	43	68.8	64.9	13	42	58
		Natural gas	26	150.3	121.0	4	4	4
		Other gas	4	8.0	4.8	21	21	21
		Total	73	227.1	190.7	4	39	48
	Pumped storage hydraulic turbine	Water	5	508.5	562.5	25	39	39
		Total	5	508.5	562.5	25	39	39
	Steam turbine	Coal	31	5,304.4	4,923.7	27	38	47
		Natural gas	8	249.0	235.8	27	52	55
		Total	39	5,553.4	5,159.5	27	42	49
	Wind turbine	Wind	7	229.3	227.7	2	5	7
		Total	7	229.3	227.7	2	5	7
	Total	Coal	31	5,304.4	4,923.7	27	38	47
		Distillate fuel oil	45	198.2	164.9	29	42	57
		Natural gas	98	5,493.4	4,456.1	4	6	18
		Other gas	6	15.0	9.8	6	21	21
		Water	54	1,142.6	1,208.6	21	50	74
		Wind	7	229.3	227.7	2	5	7
		Total	**241**	**12,382.9**	**10,990.8**	**6**	**22**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Connecticut	Combined cycle	Natural gas	13	2,076.4	1,785.9	4	8	16
		Total	13	2,076.4	1,785.9	4	8	16
	Combustion (gas) turbine	Distillate fuel oil	5	104.9	96.8	2	2	34
		Natural gas	6	275.8	216.0	5	5	5
		Other gas	1	3.0	2.9	15	15	15
		Other petroleum	18	554.4	439.1	21	37	38
		Total	30	938.1	754.8	5	28	37
	Hydraulic turbine	Water	28	128.6	133.1	20	81	92
		Total	28	128.6	133.1	20	81	92
	Internal combustion engine	Distillate fuel oil	3	6.4	6.5	16	39	39
		Other gas	3	2.7	2.7	8	8	8
		Total	6	9.1	9.2	8	12	39
	Pumped storage hydraulic turbine	Water	2	7.0	4.0	77	78	78
		Total	2	7.0	4.0	77	78	78
	Steam turbine	Coal	2	613.9	555.3	17	28	38
		Nuclear material	2	2,162.9	2,037.1	20	26	31
		Other petroleum	11	2,414.2	2,366.4	35	45	49
		Waste	8	247.1	186.6	15	18	18
		Total	23	5,438.1	5,145.4	18	31	45
	Total	Coal	2	613.9	555.3	17	28	38
		Distillate fuel oil	8	111.3	103.3	2	25	39
		Natural gas	19	2,352.2	2,001.9	4	5	16
		Nuclear material	2	2,162.9	2,037.1	20	26	31
		Other gas	4	5.7	5.6	8	8	12
		Other petroleum	29	2,968.6	2,805.5	35	37	42
		Waste	8	247.1	186.6	15	18	18
		Water	30	135.6	137.1	20	80	92
		Total	**102**	**8,597.3**	**7,832.4**	**14**	**26**	**46**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Delaware	Combined cycle	Natural gas	8	1,193.0	1,087.5	5	9	16
		Total	8	1,193.0	1,087.5	5	9	16
	Combustion (gas) turbine	Distillate fuel oil	5	124.0	105.0	38	39	42
		Natural gas	4	190.1	192.4	5	5	10
		Other gas	2	184.0	172.0	6	6	6
		Total	11	498.1	469.4	5	15	39
	Internal combustion engine	Distillate fuel oil	5	7.0	6.8	44	48	52
		Total	5	7.0	6.8	44	48	52
	Steam turbine	Coal	10	1,082.2	1,083.0	36	48	67
		Other gas	4	140.0	135.0	35	48	50
		Other petroleum	4	597.2	581.0	32	39	44
		Total	18	1,819.4	1,799.0	33	45	50
	Total	Coal	10	1,082.2	1,083.0	36	48	67
		Distillate fuel oil	10	131.0	111.8	38	43	48
		Natural gas	12	1,383.1	1,279.9	5	5	15
		Other gas	6	324.0	307.0	6	35	50
		Other petroleum	4	597.2	581.0	32	39	44
		Total	**42**	**3,517.5**	**3,362.7**	**15**	**35**	**47**
District of Columbia	Combustion (gas) turbine	Distillate fuel oil	16	288.0	256.0	38	38	38
		Total	16	288.0	256.0	38	38	38
	Steam turbine	Distillate fuel oil	2	580.0	550.0	34	36	38
		Total	2	580.0	550.0	34	36	38
	Total	Distillate fuel oil	18	868.0	806.0	38	38	38
		Total	**18**	**868.0**	**806.0**	**38**	**38**	**38**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Florida	Combined cycle	Coal	2	326.3	255.0	10	10	10
		Natural gas	121	19,624.4	16,266.2	4	7	13
		Other gas	4	11.2	10.9	12	17	17
		Total	127	19,961.9	16,532.1	4	7	13
	Combustion (gas) turbine	Distillate fuel oil	58	3,733.6	3,118.3	31	32	33
		Natural gas	110	7,711.7	6,584.5	8	28	35
		Total	168	11,445.3	9,702.8	13	32	35
	Hydraulic turbine	Water	6	55.7	54.5	4	13	21
		Total	6	55.7	54.5	4	13	21
	Internal combustion engine	Distillate fuel oil	41	149.7	144.7	17	36	41
		Natural gas	26	88.6	80.6	25	34	39
		Other gas	11	11.7	11.2	3	9	20
		Total	78	250.0	236.5	17	33	38
	Steam turbine	Biomass	20	416.3	360.8	19	26	43
		Coal	28	11,055.8	10,148.0	20	25	38
		Natural gas	23	2,991.0	2,798.0	30	40	49
		Nuclear material	5	4,110.4	3,902.0	29	30	33
		Other	9	307.8	288.5	16	18	21
		Other petroleum	27	8,933.0	8,328.0	34	42	46
		Waste	13	499.8	422.6	15	19	21
		Waste heat	4	114.0	93.0	18	24	27
		Total	129	28,428.1	26,341.0	21	30	42
	Total	Biomass	20	416.3	360.8	19	26	43
		Coal	30	11,382.1	10,403.0	19	24	37
		Distillate fuel oil	99	3,883.3	3,263.0	28	32	36
		Natural gas	280	30,415.7	25,729.3	5	14	35
		Nuclear material	5	4,110.4	3,902.0	29	30	33
		Other	9	307.8	288.5	16	18	21
		Other gas	15	22.9	22.1	6	17	17
		Other petroleum	27	8,933.0	8,328.0	34	42	46
		Waste	13	499.8	422.6	15	19	21
		Waste heat	4	114.0	93.0	18	24	27
		Water	6	55.7	54.5	4	13	21
		Total	**508**	**60,141.0**	**52,866.8**	**11**	**25**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Georgia	Combined cycle	Natural gas	30	5,832.6	5,292.6	2	4	4
		Total	30	5,832.6	5,292.6	2	4	4
	Combustion (gas) turbine	Distillate fuel oil	28	2,216.4	1,871.0	6	34	34
		Natural gas	79	8,505.5	7,201.6	5	6	11
		Total	107	10,721.9	9,072.6	5	6	26
	Hydraulic turbine	Water	96	1,891.5	1,971.9	43	79	92
		Total	96	1,891.5	1,971.9	43	79	92
	Internal combustion engine	Distillate fuel oil	20	41.7	41.2	17	18	22
		Natural gas	1	3.0	3.0	26	26	26
		Other gas	3	2.4	2.4	13	13	13
		Total	24	47.1	46.6	15	18	22
	Pumped storage hydraulic turbine	Water	13	1,634.6	1,675.0	4	11	26
		Total	13	1,634.6	1,675.0	4	11	26
	Steam turbine	Biomass	14	313.4	298.7	17	26	49
		Coal	40	14,409.1	13,282.8	32	41	49
		Natural gas	1	126.0	115.0	34	34	34
		Nuclear material	4	4,041.8	4,060.0	18	23	29
		Other petroleum	4	233.7	205.7	18	33	51
		Waste	2	5.5	2.5	7	7	7
		Total	65	19,129.5	17,964.6	24	36	48
	Total	Biomass	14	313.4	298.7	17	26	49
		Coal	40	14,409.1	13,282.8	32	41	49
		Distillate fuel oil	48	2,258.1	1,912.2	17	22	34
		Natural gas	111	14,467.1	12,612.2	4	6	7
		Nuclear material	4	4,041.8	4,060.0	18	23	29
		Other gas	3	2.4	2.4	13	13	13
		Other petroleum	4	233.7	205.7	18	33	51
		Waste	2	5.5	2.5	7	7	7
		Water	109	3,526.1	3,646.9	29	56	86
		Total	**335**	**39,257.2**	**36,023.3**	**6**	**24**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Hawaii	Combined cycle	Distillate fuel oil	11	275.2	237.1	6	13	29
		Other petroleum	5	304.4	224.8	6	6	15
		Total	16	579.6	461.9	6	13	16
	Combustion (gas) turbine	Distillate fuel oil	6	157.8	150.8	17	29	33
		Other gas	3	9.0	9.0	16	16	16
		Other petroleum	2	59.1	47.5	4	14	24
		Total	11	225.9	207.3	16	17	33
	Hydraulic turbine	Water	13	24.9	23.8	24	81	85
		Total	13	24.9	23.8	24	81	85
	Internal combustion engine	Distillate fuel oil	63	207.4	200.3	10	19	33
		Total	63	207.4	200.3	10	19	33
	Steam turbine	Biomass	4	50.1	48.6	9	18	29
		Coal	1	203.0	180.0	14	14	14
		Geothermal	10	35.0	31.0	14	14	14
		Other petroleum	23	1,187.7	1,133.6	36	43	52
		Waste	1	63.7	60.0	17	17	17
		Total	39	1,539.5	1,453.2	14	34	47
	Wind turbine	Wind	3	11.4	11.4	19	21	21
		Total	3	11.4	11.4	19	21	21
	Total	Biomass	4	50.1	48.6	9	18	29
		Coal	1	203.0	180.0	14	14	14
		Distillate fuel oil	80	640.4	588.2	12	19	33
		Geothermal	10	35.0	31.0	14	14	14
		Other gas	3	9.0	9.0	16	16	16
		Other petroleum	30	1,551.2	1,405.9	24	40	49
		Waste	1	63.7	60.0	17	17	17
		Water	13	24.9	23.8	24	81	85
		Wind	3	11.4	11.4	19	21	21
		Total	**145**	**2,588.7**	**2,357.8**	**14**	**21**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Idaho	Combined cycle	Natural gas	4	322.3	268.8	5	8	10
		Total	4	322.3	268.8	5	8	10
	Combustion (gas) turbine	Natural gas	5	439.2	376.0	5	5	11
		Total	5	439.2	376.0	5	5	11
	Hydraulic turbine	Water	169	2,521.4	2,390.1	18	23	57
		Total	169	2,521.4	2,390.1	18	23	57
	Internal combustion engine	Distillate fuel oil	2	5.0	5.4	39	39	39
		Total	2	5.0	5.4	39	39	39
	Steam turbine	Biomass	6	126.2	77.7	23	25	29
		Coal	6	18.9	16.9	38	57	58
		Other	1	15.9	14.8	20	20	20
		Total	13	161.0	109.4	23	29	56
	Wind turbine	Wind	1	10.5	10.5	1	1	1
		Total	1	10.5	10.5	1	1	1
	Total	Biomass	6	126.2	77.7	23	25	29
		Coal	6	18.9	16.9	38	57	58
		Distillate fuel oil	2	5.0	5.4	39	39	39
		Natural gas	9	761.5	644.8	5	5	10
		Other	1	15.9	14.8	20	20	20
		Water	169	2,521.4	2,390.1	18	23	57
		Wind	1	10.5	10.5	1	1	1
		Total	**194**	**3,459.4**	**3,160.2**	**17**	**23**	**56**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Illinois	Combined cycle	Natural gas	23	3,479.2	2,964.0	4	5	8
		Other gas	4	25.0	19.0	9	9	9
		Total	27	3,504.2	2,983.0	4	5	9
	Combustion (gas) turbine	Distillate fuel oil	12	133.2	105.1	5	6	35
		Natural gas	175	13,116.1	10,505.6	4	5	7
		Other gas	17	82.8	76.2	7	10	17
		Other petroleum	12	400.8	305.0	38	38	38
		Total	216	13,732.9	10,991.9	4	6	15
	Hydraulic turbine	Water	19	28.5	24.1	15	77	81
		Total	19	28.5	24.1	15	77	81
	Internal combustion engine	Distillate fuel oil	117	217.5	206.4	6	26	47
		Natural gas	70	158.6	149.8	13	14	39
		Other gas	55	57.5	52.0	7	9	9
		Total	242	433.6	408.1	7	13	38
	Steam turbine	Coal	77	17,348.5	15,542.2	28	41	51
		Natural gas	12	217.2	183.7	50	57	58
		Nuclear material	11	11,882.0	11,388.0	19	22	34
		Other coal	3	99.0	120.0	43	43	43
		Other gas	2	17.7	17.7	19	20	20
		Other petroleum	6	439.7	424.0	56	57	59
		Total	111	30,004.1	27,675.6	24	41	52
	Wind turbine	Wind	2	103.4	103.4	1	2	3
		Total	2	103.4	103.4	1	2	3
	Total	Coal	77	17,348.5	15,542.2	28	41	51
		Distillate fuel oil	129	350.7	311.5	6	24	42
		Natural gas	280	16,971.1	13,803.1	4	6	18
		Nuclear material	11	11,882.0	11,388.0	19	22	34
		Other coal	3	99.0	120.0	43	43	43
		Other gas	78	183.0	164.9	7	9	10
		Other petroleum	18	840.5	729.0	38	38	56
		Water	19	28.5	24.1	15	77	81
		Wind	2	103.4	103.4	1	2	3
		Total	**617**	**47,806.7**	**42,186.1**	**6**	**13**	**38**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Indiana	Combined cycle	Coal	2	304.5	274.0	11	32	53
		Natural gas	19	2,829.9	2,479.6	2	3	4
		Total	21	3,134.4	2,753.6	2	4	9
	Combustion (gas) turbine	Distillate fuel oil	11	252.4	242.0	33	37	38
		Natural gas	53	3,931.5	3,228.7	5	6	14
		Total	64	4,183.9	3,470.7	5	6	33
	Hydraulic turbine	Water	21	92.1	59.5	17	39	83
		Total	21	92.1	59.5	17	39	83
	Internal combustion engine	Distillate fuel oil	28	56.0	53.6	14	34	39
		Other gas	12	9.6	9.6	7	12	12
		Total	40	65.6	63.2	12	14	37
	Other	Other gas	1	15.0	10.0	25	25	25
		Total	1	15.0	10.0	25	25	25
	Steam turbine	Coal	72	20,746.8	19,006.0	33	43	51
		Distillate fuel oil	5	202.0	188.0	57	59	62
		Other gas	9	489.2	377.4	36	37	47
		Waste	1	6.5	5.0	18	18	18
		Waste heat	1	94.6	88.0	8	8	8
		Total	88	21,539.1	19,664.4	33	44	51
	Total	Coal	74	21,051.3	19,280.0	32	43	51
		Distillate fuel oil	44	510.4	483.6	21	35	39
		Natural gas	72	6,761.4	5,708.3	4	6	12
		Other gas	22	513.8	397.0	9	12	37
		Waste	1	6.5	5.0	18	18	18
		Waste heat	1	94.6	88.0	8	8	8
		Water	21	92.1	59.5	17	39	83
		Total	**235**	**29,030.1**	**26,021.4**	**7**	**30**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Iowa	Combined cycle	Natural gas	11	1,245.4	1,128.9	2	3	49
		Total	11	1,245.4	1,128.9	2	3	49
	Combustion (gas) turbine	Distillate fuel oil	14	472.0	405.4	6	16	28
		Natural gas	39	1,371.0	1,144.8	12	28	37
		Other petroleum	1	23.8	17.0	36	36	36
		Total	54	1,866.8	1,567.2	12	22	36
	Hydraulic turbine	Water	23	131.3	131.4	75	93	93
		Total	23	131.3	131.4	75	93	93
	Internal combustion engine	Distillate fuel oil	265	451.7	438.9	6	16	48
		Natural gas	28	64.3	60.1	28	37	45
		Other gas	10	8.0	8.0	8	8	8
		Total	303	524.0	507.0	6	19	47
	Steam turbine	Coal	61	6,378.1	6,029.2	25	39	49
		Natural gas	1	18.7	17.2	59	59	59
		Nuclear material	1	597.1	580.6	31	31	31
		Total	63	6,993.9	6,627.0	25	39	50
	Wind turbine	Wind	8	816.7	816.7	3	5	7
		Total	8	816.7	816.7	3	5	7
	Total	Coal	61	6,378.1	6,029.2	25	39	49
		Distillate fuel oil	279	923.7	844.3	6	16	47
		Natural gas	79	2,699.4	2,351.0	12	32	39
		Nuclear material	1	597.1	580.6	31	31	31
		Other gas	10	8.0	8.0	8	8	8
		Other petroleum	1	23.8	17.0	36	36	36
		Water	23	131.3	131.4	75	93	93
		Wind	8	816.7	816.7	3	5	7
		Total	**462**	**11,578.1**	**10,778.2**	**6**	**30**	**48**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Kansas	Combustion (gas) turbine	Distillate fuel oil	4	288.6	230.1	30	31	32
		Natural gas	37	1,965.1	1,565.0	6	24	33
		Total	41	2,253.7	1,795.1	6	27	33
	Hydraulic turbine	Water	6	2.2	2.2	81	84	84
		Total	6	2.2	2.2	81	84	84
	Internal combustion engine	Distillate fuel oil	184	345.5	318.0	12	35	46
		Natural gas	112	284.7	267.3	24	39	49
		Total	296	630.2	585.3	18	36	48
	Steam turbine	Coal	16	5,472.3	5,249.8	27	35	48
		Natural gas	27	1,705.0	1,663.0	41	47	55
		Nuclear material	1	1,235.7	1,166.0	21	21	21
		Total	44	8,413.0	8,078.8	35	45	52
	Wind turbine	Wind	4	263.4	263.4	3	6	7
		Total	4	263.4	263.4	3	6	7
	Total	Coal	16	5,472.3	5,249.8	27	35	48
		Distillate fuel oil	188	634.1	548.1	13	35	46
		Natural gas	176	3,954.8	3,495.3	23	38	48
		Nuclear material	1	1,235.7	1,166.0	21	21	21
		Water	6	2.2	2.2	81	84	84
		Wind	4	263.4	263.4	3	6	7
		Total	**391**	**11,562.5**	**10,724.8**	**20**	**36**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Kentucky	Combustion (gas) turbine	Distillate fuel oil	1	98.8	65.0	30	30	30
		Natural gas	47	5,890.3	4,657.0	4	5	11
		Total	48	5,989.1	4,722.0	4	5	11
	Hydraulic turbine	Water	30	777.4	817.1	54	62	78
		Total	30	777.4	817.1	54	62	78
	Internal combustion engine	Distillate fuel oil	9	13.9	13.9	52	57	58
		Other gas	12	9.6	9.6	3	3	3
		Total	21	23.5	23.5	3	3	54
	Steam turbine	Biomass	2	5.0	3.3	4	8	11
		Coal	56	16,509.5	14,337.1	32	39	50
		Distillate fuel oil	2	62.4	58.0	58	59	59
		Total	60	16,576.9	14,398.4	31	39	51
	Total	Biomass	2	5.0	3.3	4	8	11
		Coal	56	16,509.5	14,337.1	32	39	50
		Distillate fuel oil	12	175.1	136.9	42	58	59
		Natural gas	47	5,890.3	4,657.0	4	5	11
		Other gas	12	9.6	9.6	3	3	3
		Water	30	777.4	817.1	54	62	78
		Total	**159**	**23,366.9**	**19,961.0**	**5**	**36**	**52**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Louisiana	Combined cycle	Natural gas	62	8,924.5	7,699.3	4	5	28
		Total	62	8,924.5	7,699.3	4	5	28
	Combustion (gas) turbine	Natural gas	38	2,065.0	1,696.4	5	6	9
		Total	38	2,065.0	1,696.4	5	6	9
	Hydraulic turbine	Water	8	192.0	192.0	16	16	16
		Total	8	192.0	192.0	16	16	16
	Internal combustion engine	Distillate fuel oil	3	18.5	15.0	37	37	41
		Natural gas	10	17.8	15.6	44	49	55
		Total	13	36.3	30.6	41	44	53
	Other	Natural gas	1	4.5	3.1	2	2	2
		Total	1	4.5	3.1	2	2	2
	Steam turbine	Biomass	1	12.1	10.9	22	22	22
		Coal	6	3,764.3	3,453.0	23	24	24
		Natural gas	68	11,107.8	10,127.9	34	39	46
		Nuclear material	2	2,235.7	2,124.0	20	21	21
		Other	2	22.0	20.5	38	38	38
		Other gas	3	75.0	63.9	37	64	64
		Other petroleum	2	227.2	213.0	47	47	47
		Purchased steam	1	7.2	7.2	1	1	1
		Total	85	17,451.3	16,020.3	31	38	46
	Total	Biomass	1	12.1	10.9	22	22	22
		Coal	6	3,764.3	3,453.0	23	24	24
		Distillate fuel oil	3	18.5	15.0	37	37	41
		Natural gas	179	22,119.6	19,542.3	5	28	41
		Nuclear material	2	2,235.7	2,124.0	20	21	21
		Other	2	22.0	20.5	38	38	38
		Other gas	3	75.0	63.9	37	64	64
		Other petroleum	2	227.2	213.0	47	47	47
		Purchased steam	1	7.2	7.2	1	1	1
		Water	8	192.0	192.0	16	16	16
		Total	**207**	**28,673.6**	**25,641.7**	**6**	**24**	**40**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Maine	Combined cycle	Natural gas	8	1,377.0	1,250.0	5	6	6
		Total	8	1,377.0	1,250.0	5	6	6
	Combustion (gas) turbine	Distillate fuel oil	2	35.0	29.4	36	36	36
		Natural gas	5	359.8	314.8	5	6	7
		Total	7	394.8	344.2	5	7	36
	Hydraulic turbine	Water	251	677.0	678.0	22	66	86
		Total	251	677.0	678.0	22	66	86
	Internal combustion engine	Distillate fuel oil	20	36.0	32.7	45	47	57
		Total	20	36.0	32.7	45	47	57
	Steam turbine	Biomass	26	657.8	618.6	17	21	36
		Coal	1	102.6	85.0	16	16	16
		Natural gas	1	72.0	72.0	18	18	18
		Other petroleum	11	966.1	940.4	36	48	50
		Waste	4	65.6	53.4	16	19	19
		Total	43	1,864.1	1,769.4	18	24	41
	Total	Biomass	26	657.8	618.6	17	21	36
		Coal	1	102.6	85.0	16	16	16
		Distillate fuel oil	22	71.0	62.1	45	46	57
		Natural gas	14	1,808.8	1,636.8	5	6	6
		Other petroleum	11	966.1	940.4	36	48	50
		Waste	4	65.6	53.4	16	19	19
		Water	251	677.0	678.0	22	66	86
		Total	**329**	**4,348.9**	**4,074.3**	**20**	**52**	**86**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Maryland	Combined cycle	Natural gas	3	288.8	230.0	10	10	10
		Total	3	288.8	230.0	10	10	10
	Combustion (gas) turbine	Distillate fuel oil	30	1,514.0	1,305.0	16	34	36
		Natural gas	15	1,364.1	1,175.2	3	37	37
		Other petroleum	1	135.0	127.0	36	36	36
		Total	46	3,013.1	2,607.2	15	35	37
	Hydraulic turbine	Water	13	494.4	566.0	42	78	78
		Total	13	494.4	566.0	42	78	78
	Internal combustion engine	Distillate fuel oil	25	60.9	57.4	11	33	38
		Other gas	4	4.0	3.9	3	3	3
		Other petroleum	4	25.0	25.0	17	23	28
		Total	33	89.9	86.3	11	18	38
	Steam turbine	Biomass	2	3.8	1.9	19	19	19
		Coal	14	3,919.3	3,654.0	40	44	47
		Natural gas	4	89.7	95.5	26	49	53
		Nuclear material	2	1,828.7	1,735.0	29	30	31
		Other coal	2	1,252.0	1,244.0	35	36	36
		Other gas	4	120.0	152.3	57	57	57
		Other petroleum	5	2,027.5	1,908.0	31	34	34
		Waste	3	132.3	115.3	5	11	22
		Total	36	9,373.3	8,906.0	24	41	48
	Total	Biomass	2	3.8	1.9	19	19	19
		Coal	14	3,919.3	3,654.0	40	44	47
		Distillate fuel oil	55	1,574.9	1,362.4	15	34	38
		Natural gas	22	1,742.6	1,500.7	10	37	37
		Nuclear material	2	1,828.7	1,735.0	29	30	31
		Other coal	2	1,252.0	1,244.0	35	36	36
		Other gas	8	124.0	156.2	3	30	57
		Other petroleum	10	2,187.5	2,060.0	25	30	34
		Waste	3	132.3	115.3	5	11	22
		Water	13	494.4	566.0	42	78	78
		Total	**131**	**13,259.5**	**12,395.5**	**15**	**36**	**42**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Massachusetts	Combined cycle	Distillate fuel oil	5	383.0	325.6	25	25	25
		Natural gas	40	6,058.5	4,819.2	4	13	16
		Other petroleum	1	95.0	87.0	31	31	31
		Total	46	6,536.5	5,231.8	4	13	18
	Combustion (gas) turbine	Distillate fuel oil	17	503.7	392.5	24	36	37
		Natural gas	8	252.2	184.9	4	8	25
		Other gas	1	5.3	4.4	6	6	6
		Other petroleum	4	126.0	107.2	31	35	37
		Total	30	887.2	689.0	11	34	36
	Hydraulic turbine	Water	71	257.7	247.4	25	78	89
		Total	71	257.7	247.4	25	78	89
	Internal combustion engine	Distillate fuel oil	35	105.3	95.5	19	28	37
		Natural gas	21	29.6	29.1	5	12	22
		Other gas	25	26.1	24.2	6	9	9
		Total	81	161.0	148.8	9	13	28
	Other	Other petroleum	1	21.1	16.6	37	37	37
		Total	1	21.1	16.6	37	37	37
	Pumped storage hydraulic turbine	Water	6	1,540.0	1,642.9	32	33	33
		Total	6	1,540.0	1,642.9	32	33	33
	Steam turbine	Biomass	1	18.0	17.0	14	14	14
		Coal	11	1,701.5	1,672.6	43	48	54
		Natural gas	7	1,004.7	943.1	26	37	59
		Nuclear material	1	670.0	684.7	34	34	34
		Other gas	1	17.5	9.0	8	8	8
		Other petroleum	15	2,333.3	2,178.4	34	38	51
		Waste	7	295.5	232.3	17	18	21
		Total	43	6,040.5	5,737.1	21	38	50
	Total	Biomass	1	18.0	17.0	14	14	14
		Coal	11	1,701.5	1,672.6	43	48	54
		Distillate fuel oil	57	992.0	813.6	21	30	37
		Natural gas	76	7,345.0	5,976.3	5	13	23
		Nuclear material	1	670.0	684.7	34	34	34
		Other gas	27	48.9	37.6	6	9	9
		Other petroleum	21	2,575.4	2,389.2	34	37	49
		Waste	7	295.5	232.3	17	18	21
		Water	77	1,797.7	1,890.3	32	76	88
		Total	**278**	**15,444.0**	**13,713.5**	**13**	**25**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Michigan	Combined cycle	Natural gas	46	5,190.6	4,749.0	4	11	16
		Other gas	5	30.3	23.8	10	10	10
		Total	51	5,220.9	4,772.8	4	10	16
	Combustion (gas) turbine	Distillate fuel oil	21	399.1	320.8	32	35	40
		Natural gas	70	3,755.7	3,262.5	5	7	37
		Total	91	4,154.8	3,583.3	6	32	38
	Hydraulic turbine	Water	208	360.6	229.8	43	77	89
		Total	208	360.6	229.8	43	77	89
	Internal combustion engine	Distillate fuel oil	135	273.2	269.3	13	36	46
		Natural gas	26	85.8	85.8	30	36	46
		Other gas	61	51.0	49.2	9	12	14
		Other petroleum	2	8.2	6.6	54	59	64
		Total	224	418.2	410.9	12	29	39
	Pumped storage hydraulic turbine	Water	6	1,978.8	1,872.0	33	33	33
		Total	6	1,978.8	1,872.0	33	33	33
	Steam turbine	Biomass	8	200.6	181.8	14	18	19
		Coal	78	12,792.6	11,889.9	33	44	51
		Natural gas	13	2,361.8	2,116.8	37	50	56
		Nuclear material	4	4,314.1	3,982.0	23	30	33
		Other petroleum	1	815.4	785.0	27	27	27
		Waste	2	86.4	79.3	17	18	18
		Total	106	20,570.9	19,034.8	28	40	51
	Wind turbine	Wind	1	1.8	0.7	5	5	5
		Total	1	1.8	0.7	5	5	5
	Total	Biomass	8	200.6	181.8	14	18	19
		Coal	78	12,792.6	11,889.9	33	44	51
		Distillate fuel oil	156	672.3	590.1	20	36	40
		Natural gas	155	11,393.9	10,214.1	5	17	37
		Nuclear material	4	4,314.1	3,982.0	23	30	33
		Other gas	66	81.3	73.0	9	12	14
		Other petroleum	3	823.6	791.6	27	54	64
		Waste	2	86.4	79.3	17	18	18
		Water	214	2,339.4	2,101.8	43	75	88
		Wind	1	1.8	0.7	5	5	5
		Total	**687**	**32,706.0**	**29,904.3**	**14**	**37**	**54**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Minnesota	Combined cycle	Natural gas	10	869.7	773.0	9	11	35
		Other gas	3	16.6	13.6	10	10	10
		Total	13	886.3	786.6	9	10	12
	Combustion (gas) turbine	Distillate fuel oil	22	517.2	411.0	14	28	32
		Natural gas	36	2,161.2	1,992.2	5	30	36
		Total	58	2,678.4	2,403.2	5	28	34
	Hydraulic turbine	Water	67	173.4	163.4	56	81	87
		Total	67	173.4	163.4	56	81	87
	Internal combustion engine	Distillate fuel oil	167	310.9	301.2	4	13	47
		Natural gas	32	93.1	87.0	24	34	45
		Other gas	6	8.9	8.3	12	12	12
		Total	205	412.9	396.5	5	26	46
	Steam turbine	Biomass	8	200.1	136.4	12	28	46
		Coal	37	5,623.1	5,392.6	35	44	49
		Natural gas	22	279.6	283.0	47	54	59
		Nuclear material	3	1,737.1	1,617.0	32	32	35
		Waste	10	95.4	81.3	19	55	57
		Total	80	7,935.3	7,510.3	34	47	55
	Wind turbine	Wind	69	685.9	685.2	3	3	5
		Total	69	685.9	685.2	3	3	5
	Total	Biomass	8	200.1	136.4	12	28	46
		Coal	37	5,623.1	5,392.6	35	44	49
		Distillate fuel oil	189	828.1	712.2	4	21	45
		Natural gas	100	3,403.6	3,135.2	9	35	46
		Nuclear material	3	1,737.1	1,617.0	32	32	35
		Other gas	9	25.5	21.9	10	12	12
		Waste	10	95.4	81.3	19	55	57
		Water	67	173.4	163.4	56	81	87
		Wind	69	685.9	685.2	3	3	5
		Total	**492**	**12,772.2**	**11,945.2**	**5**	**31**	**51**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Mississippi	Combined cycle	Natural gas	39	5,713.1	5,160.1	3	5	5
		Total	39	5,713.1	5,160.1	3	5	5
	Combustion (gas) turbine	Distillate fuel oil	2	30.0	25.0	34	36	38
		Natural gas	59	4,144.6	3,624.2	4	4	7
		Total	61	4,174.6	3,649.2	4	5	7
	Internal combustion engine	Distillate fuel oil	10	18.0	9.0	5	7	8
		Natural gas	3	3.9	9.3	5	5	5
		Total	13	21.9	18.3	5	5	8
	Steam turbine	Biomass	6	172.6	190.6	19	24	38
		Coal	9	2,696.3	2,562.9	28	29	38
		Natural gas	28	3,418.3	3,242.6	38	52	55
		Nuclear material	1	1,372.5	1,266.0	21	21	21
		Total	44	7,659.7	7,262.1	29	39	53
	Total	Biomass	6	172.6	190.6	19	24	38
		Coal	9	2,696.3	2,562.9	28	29	38
		Distillate fuel oil	12	48.0	34.0	5	8	8
		Natural gas	129	13,279.9	12,036.2	4	5	35
		Nuclear material	1	1,372.5	1,266.0	21	21	21
		Total	**157**	**17,569.3**	**16,089.7**	**4**	**6**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Missouri	Combined cycle	Natural gas	14	2,152.9	1,867.0	5	6	7
		Total	14	2,152.9	1,867.0	5	6	7
	Combustion (gas) turbine	Distillate fuel oil	24	1,038.9	961.0	29	31	34
		Natural gas	61	4,114.2	3,450.4	4	6	27
		Total	85	5,153.1	4,411.4	5	20	31
	Hydraulic turbine	Water	20	499.2	552.2	47	75	75
		Total	20	499.2	552.2	47	75	75
	Internal combustion engine	Distillate fuel oil	172	291.4	273.1	8	21	40
		Natural gas	39	146.6	138.7	27	35	43
		Total	211	438.0	411.8	10	25	41
	Pumped storage hydraulic turbine	Water	9	600.4	657.0	24	24	27
		Total	9	600.4	657.0	24	24	27
	Steam turbine	Coal	55	11,803.9	11,266.3	34	41	49
		Natural gas	6	117.7	111.9	36	46	56
		Nuclear material	1	1,235.8	1,190.0	22	22	22
		Total	62	13,157.4	12,568.2	34	42	49
	Total	Coal	55	11,803.9	11,266.3	34	41	49
		Distillate fuel oil	196	1,330.3	1,234.1	10	25	39
		Natural gas	120	6,531.4	5,568.0	5	15	34
		Nuclear material	1	1,235.8	1,190.0	22	22	22
		Water	29	1,099.6	1,209.2	27	47	75
		Total	**401**	**22,001.0**	**20,467.6**	**9**	**29**	**42**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Montana	Combustion (gas) turbine	Natural gas	3	107.0	100.2	3	27	34
		Total	3	107.0	100.2	3	27	34
	Hydraulic turbine	Water	76	2,434.5	2,554.8	48	81	91
		Total	76	2,434.5	2,554.8	48	81	91
	Internal combustion engine	Distillate fuel oil	1	1.8	2.0	1	1	1
		Total	1	1.8	2.0	1	1	1
	Steam turbine	Biomass	2	10.8	10.8	16	31	46
		Coal	6	2,494.8	2,304.3	22	31	38
		Other coal	1	41.5	35.0	16	16	16
		Other petroleum	1	65.0	55.0	11	11	11
		Total	10	2,612.1	2,405.1	16	26	38
	Wind turbine	Wind	1	135.0	135.0	1	1	1
		Total	1	135.0	135.0	1	1	1
	Total	Biomass	2	10.8	10.8	16	31	46
		Coal	6	2,494.8	2,304.3	22	31	38
		Distillate fuel oil	1	1.8	2.0	1	1	1
		Natural gas	3	107.0	100.2	3	27	34
		Other coal	1	41.5	35.0	16	16	16
		Other petroleum	1	65.0	55.0	11	11	11
		Water	76	2,434.5	2,554.8	48	81	91
		Wind	1	135.0	135.0	1	1	1
		Total	**91**	**5,290.4**	**5,197.1**	**40**	**68**	**91**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Nebraska	Combined cycle	Natural gas	7	468.3	406.9	1	2	3
		Total	7	468.3	406.9	1	2	3
	Combustion (gas) turbine	Distillate fuel oil	9	577.6	530.3	10	33	33
		Natural gas	12	964.9	784.0	3	7	34
		Total	21	1,542.5	1,314.3	5	31	33
	Hydraulic turbine	Water	18	310.3	258.7	54	65	70
		Total	18	310.3	258.7	54	65	70
	Internal combustion engine	Distillate fuel oil	85	105.1	97.8	19	46	54
		Natural gas	74	159.6	144.9	35	43	51
		Other gas	10	7.7	7.6	4	12	19
		Total	169	272.4	250.3	30	42	53
	Steam turbine	Coal	15	3,203.7	3,195.8	27	41	47
		Natural gas	6	245.8	222.5	39	46	49
		Nuclear material	2	1,303.0	1,238.3	32	33	33
		Total	23	4,752.5	4,656.6	29	41	48
	Wind turbine	Wind	6	72.5	72.5	4	8	8
		Total	6	72.5	72.5	4	8	8
	Total	Coal	15	3,203.7	3,195.8	27	41	47
		Distillate fuel oil	94	682.7	628.1	19	40	54
		Natural gas	99	1,838.6	1,558.3	32	39	50
		Nuclear material	2	1,303.0	1,238.3	32	33	33
		Other gas	10	7.7	7.6	4	12	19
		Water	18	310.3	258.7	54	65	70
		Wind	6	72.5	72.5	4	8	8
		Total	**244**	**7,418.5**	**6,959.3**	**24**	**40**	**51**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Nevada	Combined cycle	Natural gas	39	3,943.0	3,188.4	3	12	14
		Total	39	3,943.0	3,188.4	3	12	14
	Combustion (gas) turbine	Distillate fuel oil	2	25.0	20.0	44	45	45
		Natural gas	15	1,024.8	860.0	5	12	15
		Total	17	1,049.8	880.0	5	12	32
	Geothermal binary cycle turbine	Geothermal	27	77.2	39.5	17	17	20
		Total	27	77.2	39.5	17	17	20
	Hydraulic turbine	Water	16	1,047.0	1,047.2	69	70	95
		Total	16	1,047.0	1,047.2	69	70	95
	Internal combustion engine	Distillate fuel oil	12	25.4	24.6	39	43	46
		Total	12	25.4	24.6	39	43	46
	Steam turbine	Coal	6	1,133.2	1,077.0	23	28	38
		Geothermal	27	203.9	145.8	14	16	19
		Natural gas	9	724.8	731.0	38	42	45
		Total	42	2,061.9	1,953.8	16	19	32
	Total	Coal	6	1,133.2	1,077.0	23	28	38
		Distillate fuel oil	14	50.4	44.6	39	45	46
		Geothermal	54	281.1	185.3	16	17	19
		Natural gas	63	5,692.6	4,779.4	5	12	24
		Water	16	1,047.0	1,047.2	69	70	95
		Total	**153**	**8,204.3**	**7,133.5**	**14**	**17**	**37**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New Hampshire	Combined cycle	Natural gas	6	1,505.5	1,322.0	3	4	4
		Total	6	1,505.5	1,322.0	3	4	4
	Combustion (gas) turbine	Distillate fuel oil	1	18.0	14.1	37	37	37
		Natural gas	3	17.2	14.9	5	5	5
		Other gas	2	6.0	5.8	9	9	9
		Other petroleum	4	77.0	68.1	37	38	38
		Total	10	118.2	102.9	5	23	37
	Hydraulic turbine	Water	92	444.2	506.0	21	38	82
		Total	92	444.2	506.0	21	38	82
	Internal combustion engine	Distillate fuel oil	4	3.8	3.8	9	17	34
		Other gas	8	7.6	7.1	12	14	16
		Total	12	11.4	10.9	11	14	18
	Steam turbine	Biomass	8	103.3	88.4	18	19	20
		Coal	5	609.2	575.1	46	49	51
		Natural gas	1	6.5	6.5	59	59	59
		Nuclear material	1	1,242.0	1,220.1	16	16	16
		Other petroleum	3	441.5	422.7	2	32	80
		Waste	2	18.5	18.5	17	18	19
		Total	20	2,421.0	2,331.3	18	20	49
	Total	Biomass	8	103.3	88.4	18	19	20
		Coal	5	609.2	575.1	46	49	51
		Distillate fuel oil	5	21.8	17.9	12	21	37
		Natural gas	10	1,529.2	1,343.4	3	4	5
		Nuclear material	1	1,242.0	1,220.1	16	16	16
		Other gas	10	13.6	12.9	10	14	14
		Other petroleum	7	518.5	490.8	32	37	38
		Waste	2	18.5	18.5	17	18	19
		Water	92	444.2	506.0	21	38	82
		Total	**140**	**4,500.3**	**4,273.1**	**18**	**24**	**76**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New Jersey	Combined cycle	Natural gas	55	5,347.3	4,482.1	12	15	17
		Other gas	3	22.5	18.8	5	5	45
		Total	58	5,369.8	4,500.9	12	15	17
	Combustion (gas) turbine	Distillate fuel oil	4	186.0	185.0	34	34	34
		Natural gas	86	3,865.8	3,456.4	12	34	35
		Other gas	1	10.3	7.4	8	8	8
		Other petroleum	23	888.4	881.0	34	35	37
		Total	114	4,950.5	4,529.8	17	34	35
	Hydraulic turbine	Water	3	10.8	0.9	21	21	21
		Total	3	10.8	0.9	21	21	21
	Internal combustion engine	Distillate fuel oil	4	8.0	8.0	45	45	45
		Natural gas	6	16.4	10.5	9	18	23
		Other gas	17	14.5	14.1	8	9	16
		Total	27	38.9	32.6	9	16	21
	Pumped storage hydraulic turbine	Water	3	453.0	400.0	41	41	41
		Total	3	453.0	400.0	41	41	41
	Steam turbine	Coal	9	2,237.2	2,076.6	36	42	45
		Natural gas	7	969.6	843.6	42	55	58
		Nuclear material	4	4,150.7	3,984.0	23	27	33
		Other	1	11.2	11.2	39	39	39
		Other gas	1	9.9	9.5	9	9	9
		Other petroleum	5	568.2	613.0	46	49	49
		Waste	7	177.3	149.5	15	16	16
		Total	34	8,124.1	7,687.4	16	38	48
	Total	Coal	9	2,237.2	2,076.6	36	42	45
		Distillate fuel oil	8	194.0	193.0	34	40	45
		Natural gas	154	10,199.1	8,792.7	12	17	35
		Nuclear material	4	4,150.7	3,984.0	23	27	33
		Other	1	11.2	11.2	39	39	39
		Other gas	22	57.2	49.8	8	9	16
		Other petroleum	28	1,456.6	1,494.0	34	36	38
		Waste	7	177.3	149.5	15	16	16
		Water	6	463.8	400.9	21	31	41
		Total	**239**	**18,947.1**	**17,151.7**	**13**	**21**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New Mexico	Combined cycle	Natural gas	8	322.6	281.4	3	9	49
		Total	8	322.6	281.4	3	9	49
	Combustion (gas) turbine	Distillate fuel oil	1	20.0	20.0	33	33	33
		Natural gas	15	858.6	745.2	3	8	25
		Total	16	878.6	765.2	4	8	27
	Hydraulic turbine	Water	6	58.1	60.1	17	66	66
		Total	6	58.1	60.1	17	66	66
	Internal combustion engine	Distillate fuel oil	6	16.1	15.0	31	40	47
		Natural gas	12	41.4	39.7	34	35	39
		Other gas	4	6.6	6.4	4	12	19
		Total	22	64.1	61.1	29	35	39
	Steam turbine	Coal	11	4,382.1	3,956.9	27	36	43
		Natural gas	13	828.4	797.0	44	47	49
		Total	24	5,210.5	4,753.9	35	43	48
	Wind turbine	Wind	4	404.0	404.0	1	2	3
		Total	4	404.0	404.0	1	2	3
	Total	Coal	11	4,382.1	3,956.9	27	36	43
		Distillate fuel oil	7	36.1	35.0	31	38	47
		Natural gas	48	2,051.0	1,863.3	7	34	45
		Other gas	4	6.6	6.4	4	12	19
		Water	6	58.1	60.1	17	66	66
		Wind	4	404.0	404.0	1	2	3
		Total	**80**	**6,937.9**	**6,325.7**	**9**	**34**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
New York	Combined cycle	Distillate fuel oil	1	56.0	48.6	12	12	12
		Natural gas	88	7,170.0	5,987.4	11	12	14
		Total	89	7,226.0	6,036.0	11	12	14
	Combustion (gas) turbine	Distillate fuel oil	45	1,608.2	1,450.1	32	35	35
		Natural gas	111	3,563.2	2,967.1	12	35	36
		Other petroleum	15	412.1	323.1	35	36	37
		Total	171	5,583.5	4,740.2	31	35	36
	Hydraulic turbine	Water	364	4,609.6	4,168.1	21	57	82
		Total	364	4,609.6	4,168.1	21	57	82
	Internal combustion engine	Distillate fuel oil	21	43.7	39.6	35	41	44
		Natural gas	13	12.3	11.1	12	15	16
		Other gas	54	44.3	42.6	5	10	15
		Total	88	100.3	93.3	8	15	18
	Pumped storage hydraulic turbine	Water	16	1,240.0	1,296.8	39	44	44
		Total	16	1,240.0	1,296.8	39	44	44
	Steam turbine	Biomass	2	40.8	37.0	13	14	14
		Coal	40	4,120.6	4,067.8	39	50	56
		Natural gas	21	6,886.7	6,653.1	37	43	50
		Nuclear material	6	5,611.2	5,150.2	30	35	37
		Other petroleum	14	5,648.0	5,324.0	32	40	51
		Waste	11	314.8	249.4	15	19	22
		Total	94	22,622.1	21,481.5	30	41	52
	Wind turbine	Wind	4	185.1	185.1	3	6	6
		Total	4	185.1	185.1	3	6	6
	Total	Biomass	2	40.8	37.0	13	14	14
		Coal	40	4,120.6	4,067.8	39	50	56
		Distillate fuel oil	67	1,707.9	1,538.3	32	35	39
		Natural gas	233	17,632.2	15,618.6	12	15	35
		Nuclear material	6	5,611.2	5,150.2	30	35	37
		Other gas	54	44.3	42.6	5	10	15
		Other petroleum	29	6,060.1	5,647.1	34	36	39
		Waste	11	314.8	249.4	15	19	22
		Water	380	5,849.6	5,464.9	22	53	82
		Wind	4	185.1	185.1	3	6	6
		Total	**826**	**41,566.6**	**38,000.9**	**16**	**35**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
North Carolina	Combined cycle	Distillate fuel oil	6	102.0	84.0	37	37	82
		Natural gas	13	1,019.6	862.0	16	18	28
		Total	19	1,121.6	946.0	16	28	37
	Combustion (gas) turbine	Distillate fuel oil	20	528.1	410.5	35	35	37
		Natural gas	53	6,507.4	5,135.2	6	11	14
		Other gas	2	9.8	7.6	7	9	10
		Total	75	7,045.3	5,553.3	6	11	35
	Hydraulic turbine	Water	99	1,824.7	1,942.4	44	76	83
		Total	99	1,824.7	1,942.4	44	76	83
	Internal combustion engine	Distillate fuel oil	13	25.2	25.2	12	15	15
		Other gas	3	2.9	2.9	4	7	7
		Total	16	28.1	28.1	7	15	15
	Pumped storage hydraulic turbine	Water	1	95.0	94.9	50	50	50
		Total	1	95.0	94.9	50	50	50
	Steam turbine	Biomass	4	208.1	193.4	18	24	29
		Coal	58	13,188.5	13,102.5	33	47	54
		Nuclear material	5	5,181.5	4,938.0	22	25	29
		Other	1	39.9	37.1	22	22	22
		Waste	2	10.5	3.6	4	10	15
		Total	70	18,628.5	18,274.6	23	41	53
	Total	Biomass	4	208.1	193.4	18	24	29
		Coal	58	13,188.5	13,102.5	33	47	54
		Distillate fuel oil	39	655.3	519.7	15	35	37
		Natural gas	66	7,527.0	5,997.2	6	11	27
		Nuclear material	5	5,181.5	4,938.0	22	25	29
		Other	1	39.9	37.1	22	22	22
		Other gas	5	12.7	10.5	7	7	7
		Waste	2	10.5	3.6	4	10	15
		Water	100	1,919.7	2,037.3	44	74	83
		Total	**280**	**28,743.2**	**26,839.3**	**16**	**37**	**57**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
North Dakota	Combustion (gas) turbine	Distillate fuel oil	2	48.2	46.5	28	29	30
		Natural gas	2	10.0	9.6	53	53	53
		Total	4	58.2	56.1	29	42	53
	Hydraulic turbine	Water	5	614.0	432.0	46	50	50
		Total	5	614.0	432.0	46	50	50
	Internal combustion engine	Distillate fuel oil	23	28.9	28.8	50	57	60
		Total	23	28.9	28.8	50	57	60
	Steam turbine	Coal	12	4,225.0	4,105.9	26	30	40
		Total	12	4,225.0	4,105.9	26	30	40
	Wind turbine	Wind	4	95.6	95.6	2	3	3
		Total	4	95.6	95.6	2	3	3
	Total	Coal	12	4,225.0	4,105.9	26	30	40
		Distillate fuel oil	25	77.1	75.3	30	57	60
		Natural gas	2	10.0	9.6	53	53	53
		Water	5	614.0	432.0	46	50	50
		Wind	4	95.6	95.6	2	3	3
		Total	**48**	**5,021.7**	**4,718.4**	**27**	**48**	**57**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Ohio	Combined cycle	Natural gas	13	2,843.8	2,694.0	3	3	3
		Total	13	2,843.8	2,694.0	3	3	3
	Combustion (gas) turbine	Distillate fuel oil	25	767.1	635.2	33	34	37
		Natural gas	76	6,116.7	5,302.8	5	6	14
		Total	101	6,883.8	5,938.0	5	8	35
	Hydraulic turbine	Water	15	128.4	100.5	12	18	24
		Total	15	128.4	100.5	12	18	24
	Internal combustion engine	Distillate fuel oil	50	122.4	117.9	6	34	38
		Natural gas	2	5.1	5.1	10	27	43
		Other gas	2	3.8	3.6	7	7	7
		Total	54	131.3	126.6	6	34	38
	Steam turbine	Biomass	4	10.9	8.7	13	17	28
		Coal	98	23,370.8	21,901.9	34	45	52
		Natural gas	2	35.0	35.0	46	49	52
		Nuclear material	2	2,236.8	2,108.0	19	24	29
		Other gas	1	32.0	30.0	8	8	8
		Other petroleum	1	140.6	136.0	51	51	51
		Total	108	25,826.1	24,219.6	33	44	52
	Total	Biomass	4	10.9	8.7	13	17	28
		Coal	98	23,370.8	21,901.9	34	45	52
		Distillate fuel oil	75	889.5	753.1	16	34	38
		Natural gas	93	9,000.6	8,036.9	4	6	14
		Nuclear material	2	2,236.8	2,108.0	19	24	29
		Other gas	3	35.8	33.6	7	7	8
		Other petroleum	1	140.6	136.0	51	51	51
		Water	15	128.4	100.5	12	18	24
		Total	**291**	**35,813.4**	**33,078.7**	**6**	**33**	**39**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Oklahoma	Combined cycle	Natural gas	44	6,881.4	6,118.3	3	4	14
		Total	44	6,881.4	6,118.3	3	4	14
	Combustion (gas) turbine	Natural gas	23	935.0	813.4	5	16	35
		Total	23	935.0	813.4	5	16	35
	Hydraulic turbine	Water	31	757.5	780.2	36	42	53
		Total	31	757.5	780.2	36	42	53
	Internal combustion engine	Distillate fuel oil	24	62.3	56.5	28	43	55
		Natural gas	5	18.8	12.6	52	54	57
		Total	29	81.1	69.1	34	50	57
	Pumped storage hydraulic turbine	Water	6	288.0	260.0	35	37	38
		Total	6	288.0	260.0	35	37	38
	Steam turbine	Coal	12	5,606.0	5,284.1	22	26	27
		Natural gas	35	6,031.7	5,603.1	35	47	53
		Waste	1	16.8	15.6	17	17	17
		Total	48	11,654.5	10,902.8	27	38	50
	Wind turbine	Wind	6	474.3	474.3	1	2	3
		Total	6	474.3	474.3	1	2	3
	Total	Coal	12	5,606.0	5,284.1	22	26	27
		Distillate fuel oil	24	62.3	56.5	28	43	55
		Natural gas	107	13,866.9	12,547.4	4	29	43
		Waste	1	16.8	15.6	17	17	17
		Water	37	1,045.5	1,040.2	35	42	53
		Wind	6	474.3	474.3	1	2	3
		Total	**187**	**21,071.8**	**19,418.1**	**5**	**33**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Oregon	Combined cycle	Natural gas	23	3,047.6	2,547.4	5	10	32
		Total	23	3,047.6	2,547.4	5	10	32
	Combustion (gas) turbine	Natural gas	8	261.0	217.0	4	4	5
		Total	8	261.0	217.0	4	4	5
	Hydraulic turbine	Water	190	8,236.5	8,331.0	36	48	54
		Total	190	8,236.5	8,331.0	36	48	54
	Internal combustion engine	Other gas	7	5.6	5.5	11	13	14
		Total	7	5.6	5.5	11	13	14
	Steam turbine	Biomass	21	253.8	181.2	26	30	51
		Coal	1	601.0	585.0	26	26	26
		Natural gas	2	4.0	3.9	46	51	56
		Waste	1	13.1	11.5	20	20	20
		Total	25	871.9	781.6	26	30	51
	Wind turbine	Wind	7	298.5	298.0	3	4	5
		Total	7	298.5	298.0	3	4	5
	Total	Biomass	21	253.8	181.2	26	30	51
		Coal	1	601.0	585.0	26	26	26
		Natural gas	33	3,312.6	2,768.3	4	6	29
		Other gas	7	5.6	5.5	11	13	14
		Waste	1	13.1	11.5	20	20	20
		Water	190	8,236.5	8,331.0	36	48	54
		Wind	7	298.5	298.0	3	4	5
		Total	**260**	**12,721.1**	**12,180.4**	**24**	**43**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Pennsylvania	Combined cycle	Natural gas	57	9,061.5	7,728.7	3	4	9
		Total	57	9,061.5	7,728.7	3	4	9
	Combustion (gas) turbine	Distillate fuel oil	71	2,032.6	1,547.9	34	36	39
		Natural gas	31	1,801.3	1,597.9	5	5	19
		Other gas	8	27.4	23.8	5	8	13
		Total	110	3,861.3	3,169.6	10	35	37
	Hydraulic turbine	Water	49	757.4	730.0	19	73	82
		Total	49	757.4	730.0	19	73	82
	Internal combustion engine	Distillate fuel oil	26	76.1	74.3	36	38	39
		Natural gas	11	54.8	53.7	3	18	18
		Other gas	11	19.3	18.0	8	19	19
		Total	48	150.2	146.0	18	30	39
	Pumped storage hydraulic turbine	Water	11	1,269.0	1,505.0	36	39	39
		Total	11	1,269.0	1,505.0	36	39	39
	Steam turbine	Biomass	4	123.6	108.2	13	16	18
		Coal	53	18,318.0	16,714.8	36	45	52
		Distillate fuel oil	2	91.9	97.0	33	45	57
		Natural gas	1	3.0	3.0	19	19	19
		Nuclear material	9	9,859.8	9,195.0	20	23	32
		Other coal	19	2,170.9	1,926.5	14	16	20
		Other gas	3	83.2	80.0	10	10	18
		Other petroleum	6	2,903.4	2,797.0	30	32	48
		Waste	4	211.9	184.6	14	15	16
		Total	101	33,765.7	31,106.1	18	34	48
	Wind turbine	Wind	5	131.9	131.9	3	5	5
		Total	5	131.9	131.9	3	5	5
	Total	Biomass	4	123.6	108.2	13	16	18
		Coal	53	18,318.0	16,714.8	36	45	52
		Distillate fuel oil	99	2,200.6	1,719.2	35	37	39
		Natural gas	100	10,920.6	9,383.3	3	5	17
		Nuclear material	9	9,859.8	9,195.0	20	23	32
		Other coal	19	2,170.9	1,926.5	14	16	20
		Other gas	22	129.9	121.8	8	10	19
		Other petroleum	6	2,903.4	2,797.0	30	32	48
		Waste	4	211.9	184.6	14	15	16
		Water	60	2,026.4	2,235.0	20	39	80
		Wind	5	131.9	131.9	3	5	5
		Total	**381**	**48,997.0**	**44,517.3**	**14**	**32**	**39**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Rhode Island	Combined cycle	Natural gas	16	1,820.7	1,550.6	6	13	16
		Total	16	1,820.7	1,550.6	6	13	16
	Hydraulic turbine	Water	4	1.6	1.5	22	22	22
		Total	4	1.6	1.5	22	22	22
	Internal combustion engine	Other gas	15	26.1	23.7	1	16	16
		Total	15	26.1	23.7	1	16	16
	Steam turbine	Other petroleum	1	3.2	3.0	24	24	24
		Total	1	3.2	3.0	24	24	24
	Total	Natural gas	16	1,820.7	1,550.6	6	13	16
		Other gas	15	26.1	23.7	1	16	16
		Other petroleum	1	3.2	3.0	24	24	24
		Water	4	1.6	1.5	22	22	22
		Total	**36**	**1,851.6**	**1,578.8**	**5**	**16**	**16**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
South Carolina	Combined cycle	Natural gas	16	2,504.7	2,060.0	2	4	7
		Total	16	2,504.7	2,060.0	2	4	7
	Combustion (gas) turbine	Distillate fuel oil	16	708.3	563.0	32	32	34
		Natural gas	57	3,734.7	3,053.0	5	32	35
		Total	73	4,443.0	3,616.0	7	32	35
	Hydraulic turbine	Water	111	1,213.3	1,211.3	53	80	92
		Total	111	1,213.3	1,211.3	53	80	92
	Internal combustion engine	Distillate fuel oil	12	38.1	37.1	3	3	19
		Natural gas	3	3.3	3.3	19	19	19
		Other gas	6	8.8	9.0	1	2	5
		Total	21	50.2	49.4	3	3	19
	Pumped storage hydraulic turbine	Water	16	2,188.4	2,616.0	22	28	30
		Total	16	2,188.4	2,616.0	22	28	30
	Steam turbine	Biomass	2	109.6	100.0	15	19	22
		Coal	29	5,628.1	5,289.0	31	40	54
		Nuclear material	7	6,799.4	6,472.0	21	32	33
		Other coal	4	810.9	754.0	29	48	50
		Other petroleum	2	100.0	92.0	52	52	52
		Waste	1	13.0	9.5	17	17	17
		Total	45	13,461.0	12,716.5	25	36	51
	Total	Biomass	2	109.6	100.0	15	19	22
		Coal	29	5,628.1	5,289.0	31	40	54
		Distillate fuel oil	28	746.4	600.1	6	32	33
		Natural gas	76	6,242.7	5,116.3	4	17	35
		Nuclear material	7	6,799.4	6,472.0	21	32	33
		Other coal	4	810.9	754.0	29	48	50
		Other gas	6	8.8	9.0	1	2	5
		Other petroleum	2	100.0	92.0	52	52	52
		Waste	1	13.0	9.5	17	17	17
		Water	127	3,401.7	3,827.3	33	76	90
		Total	**282**	**23,860.6**	**22,269.3**	**17**	**35**	**66**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
South Dakota	Combustion (gas) turbine	Distillate fuel oil	5	255.4	185.4	28	28	28
		Natural gas	10	602.9	540.6	12	21	29
		Total	15	858.3	726.0	12	28	28
	Hydraulic turbine	Water	23	1,598.1	1,500.0	41	44	51
		Total	23	1,598.1	1,500.0	41	44	51
	Internal combustion engine	Distillate fuel oil	23	42.0	38.5	4	36	41
		Natural gas	5	12.6	12.6	32	44	44
		Total	28	54.6	51.1	10	37	44
	Steam turbine	Coal	2	481.0	482.1	31	38	45
		Total	2	481.0	482.1	31	38	45
	Wind turbine	Wind	3	43.1	43.1	3	5	5
		Total	3	43.1	43.1	3	5	5
	Total	Coal	2	481.0	482.1	31	38	45
		Distillate fuel oil	28	297.4	223.9	10	32	41
		Natural gas	15	615.5	553.2	12	29	44
		Water	23	1,598.1	1,500.0	41	44	51
		Wind	3	43.1	43.1	3	5	5
		Total	**71**	**3,035.1**	**2,802.3**	**28**	**41**	**44**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Tennessee	Combustion (gas) turbine	Natural gas	68	4,763.6	4,025.7	6	31	34
		Total	68	4,763.6	4,025.7	6	31	34
	Hydraulic turbine	Water	84	2,418.0	2,608.2	49	57	66
		Total	84	2,418.0	2,608.2	49	57	66
	Internal combustion engine	Biomass	1	2.0	1.8	1	1	1
		Distillate fuel oil	32	64.0	57.6	5	5	6
		Other gas	4	3.2	3.2	14	14	14
		Total	37	69.2	62.6	5	5	6
	Pumped storage hydraulic turbine	Water	4	1,530.0	1,597.1	27	27	28
		Total	4	1,530.0	1,597.1	27	27	28
	Steam turbine	Biomass	3	3.4	3.0	20	26	34
		Coal	33	9,780.4	8,394.0	47	51	52
		Nuclear material	3	3,710.9	3,398.0	10	24	25
		Total	39	13,494.7	11,795.0	47	49	52
	Wind turbine	Wind	4	28.8	29.1	4	6	6
		Total	4	28.8	29.1	4	6	6
	Total	Biomass	4	5.4	4.8	11	23	30
		Coal	33	9,780.4	8,394.0	47	51	52
		Distillate fuel oil	32	64.0	57.6	5	5	6
		Natural gas	68	4,763.6	4,025.7	6	31	34
		Nuclear material	3	3,710.9	3,398.0	10	24	25
		Other gas	4	3.2	3.2	14	14	14
		Water	88	3,948.0	4,205.4	49	57	65
		Wind	4	28.8	29.1	4	6	6
		Total	**236**	**22,304.3**	**20,117.8**	**6**	**35**	**53**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Texas	Combined cycle	Natural gas	255	35,903.3	31,114.8	4	6	19
		Other gas	1	104.4	104.0	10	10	10
		Total	256	36,007.7	31,218.8	4	6	19
	Combustion (gas) turbine	Natural gas	133	7,486.1	6,391.3	9	17	29
		Other gas	4	16.6	14.2	5	12	18
		Total	137	7,502.7	6,405.5	9	17	29
	Hydraulic turbine	Water	43	646.6	645.9	41	61	74
		Total	43	646.6	645.9	41	61	74
	Internal combustion engine	Distillate fuel oil	14	20.8	18.3	5	5	9
		Natural gas	4	16.2	12.6	18	19	19
		Other gas	27	31.8	35.0	3	3	3
		Total	45	68.8	65.9	3	3	5
	Other	Other	1	13.0	13.0	42	42	42
		Other petroleum	1	12.0	12.0	23	23	23
		Total	2	25.0	25.0	23	33	42
	Steam turbine	Biomass	1	5.0	5.0	23	23	23
		Coal	40	21,237.9	20,188.0	24	27	29
		Natural gas	134	27,863.1	26,839.3	34	40	48
		Nuclear material	4	5,138.6	4,860.0	15	17	18
		Other	2	7.5	6.7	36	36	36
		Other gas	6	132.2	119.9	21	22	23
		Other petroleum	1	184.0	140.0	20	20	20
		Purchased steam	4	195.0	154.0	19	27	27
		Waste heat	4	90.9	86.5	8	11	15
		Total	196	54,854.2	52,399.4	28	36	46
	Wind turbine	Wind	20	1,846.2	1,846.2	3	5	6
		Total	20	1,846.2	1,846.2	3	5	6

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Texas (continued)	Total	Biomass	1	5.0	5.0	23	23	23
		Coal	40	21,237.9	20,188.0	24	27	29
		Distillate fuel oil	14	20.8	18.3	5	5	9
		Natural gas	526	71,268.7	64,358.0	6	19	35
		Nuclear material	4	5,138.6	4,860.0	15	17	18
		Other	3	20.5	19.7	36	36	42
		Other gas	38	285.0	273.1	3	3	10
		Other petroleum	2	196.0	152.0	20	22	23
		Purchased steam	4	195.0	154.0	19	27	27
		Waste heat	4	90.9	86.5	8	11	15
		Water	43	646.6	645.9	41	61	74
		Wind	20	1,846.2	1,846.2	3	5	6
		Total	**699**	**100,951.2**	**92,606.7**	**5**	**19**	**35**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Utah	Combined cycle	Natural gas	4	432.4	402.4	1	2	2
		Total	4	432.4	402.4	1	2	2
	Combustion (gas) turbine	Natural gas	18	658.0	578.6	4	4	4
		Total	18	658.0	578.6	4	4	4
	Hydraulic turbine	Water	48	254.9	248.0	20	48	81
		Total	48	254.9	248.0	20	48	81
	Internal combustion engine	Distillate fuel oil	9	25.9	24.5	7	7	7
		Natural gas	28	70.3	63.4	5	16	20
		Total	37	96.2	87.9	5	11	19
	Steam turbine	Coal	14	4,978.8	4,800.0	23	31	52
		Geothermal	1	26.0	23.0	22	22	22
		Natural gas	3	251.6	235.0	51	54	55
		Other coal	1	58.1	51.0	13	13	13
		Waste	1	1.6	1.4	20	20	20
		Waste heat	1	31.8	31.6	11	11	11
		Total	21	5,347.9	5,142.0	20	29	52
	Total	Coal	14	4,978.8	4,800.0	23	31	52
		Distillate fuel oil	9	25.9	24.5	7	7	7
		Geothermal	1	26.0	23.0	22	22	22
		Natural gas	53	1,412.3	1,279.4	4	5	18
		Other coal	1	58.1	51.0	13	13	13
		Waste	1	1.6	1.4	20	20	20
		Waste heat	1	31.8	31.6	11	11	11
		Water	48	254.9	248.0	20	48	81
		Total	**128**	**6,789.4**	**6,458.8**	**7**	**20**	**48**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Vermont	Combustion (gas) turbine	Distillate fuel oil	6	79.1	53.9	14	38	44
		Other petroleum	1	41.8	35.0	34	34	34
		Total	7	120.9	88.9	14	35	44
	Hydraulic turbine	Water	103	286.3	296.7	22	78	89
		Total	103	286.3	296.7	22	78	89
	Internal combustion engine	Distillate fuel oil	13	16.0	15.3	52	56	59
		Total	13	16.0	15.3	52	56	59
	Steam turbine	Biomass	3	85.0	75.7	14	22	24
		Nuclear material	1	563.4	506.0	34	34	34
		Total	4	648.4	581.7	18	23	29
	Wind turbine	Wind	1	6.0	5.2	9	9	9
		Total	1	6.0	5.2	9	9	9
	Total	Biomass	3	85.0	75.7	14	22	24
		Distillate fuel oil	19	95.1	69.2	42	52	58
		Nuclear material	1	563.4	506.0	34	34	34
		Other petroleum	1	41.8	35.0	34	34	34
		Water	103	286.3	296.7	22	78	89
		Wind	1	6.0	5.2	9	9	9
		Total	**128**	**1,077.6**	**987.8**	**23**	**59**	**87**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years) 25th percentile	Median	75th percentile
Virginia	Combined cycle	Natural gas	28	3,787.1	3,319.0	6	13	15
		Total	28	3,787.1	3,319.0	6	13	15
	Combustion (gas) turbine	Distillate fuel oil	35	936.3	668.1	9	35	37
		Natural gas	34	3,828.6	3,195.3	4	5	14
		Total	69	4,764.9	3,863.4	5	14	35
	Hydraulic turbine	Water	50	711.5	645.7	52	67	91
		Total	50	711.5	645.7	52	67	91
	Internal combustion engine	Distillate fuel oil	51	99.1	96.5	9	14	19
		Other gas	16	13.4	12.8	12	13	14
		Other petroleum	2	6.0	6.0	13	15	17
		Total	69	118.5	115.3	10	14	16
	Pumped storage hydraulic turbine	Water	9	2,347.9	2,917.0	21	21	26
		Total	9	2,347.9	2,917.0	21	21	26
	Steam turbine	Biomass	14	370.6	330.6	21	33	50
		Coal	38	3,643.7	3,357.9	18	47	53
		Natural gas	4	361.6	313.7	17	34	48
		Nuclear material	4	3,654.4	3,432.0	27	31	34
		Other coal	8	2,455.1	2,326.0	24	44	51
		Other petroleum	2	1,764.0	1,604.0	31	32	32
		Waste	5	184.0	125.5	16	19	19
		Total	75	12,433.4	11,489.7	18	36	50
	Total	Biomass	14	370.6	330.6	21	33	50
		Coal	38	3,643.7	3,357.9	18	47	53
		Distillate fuel oil	86	1,035.4	764.6	9	16	36
		Natural gas	66	7,977.3	6,828.0	4	9	16
		Nuclear material	4	3,654.4	3,432.0	27	31	34
		Other coal	8	2,455.1	2,326.0	24	44	51
		Other gas	16	13.4	12.8	12	13	14
		Other petroleum	4	1,770.0	1,610.0	15	24	32
		Waste	5	184.0	125.5	16	19	19
		Water	59	3,059.4	3,562.7	40	53	91
		Total	**300**	**24,163.3**	**22,350.1**	**12**	**18**	**43**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Washington	Combined cycle	Natural gas	26	2,588.7	2,180.1	4	11	13
		Total	26	2,588.7	2,180.1	4	11	13
	Combustion (gas) turbine	Natural gas	15	869.6	726.2	4	5	25
		Total	15	869.6	726.2	4	5	25
	Hydraulic turbine	Water	279	20,586.6	21,077.2	28	46	63
		Total	279	20,586.6	21,077.2	28	46	63
	Internal combustion engine	Distillate fuel oil	21	34.7	38.5	5	5	5
		Natural gas	6	24.6	24.6	4	4	4
		Other gas	8	14.4	14.4	7	7	23
		Total	35	73.7	77.5	5	5	6
	Other	Other gas	3	2.7	2.3	7	7	7
		Total	3	2.7	2.3	7	7	7
	Pumped storage hydraulic turbine	Water	6	314.0	314.0	23	23	33
		Total	6	314.0	314.0	23	23	33
	Steam turbine	Biomass	19	270.6	257.1	23	49	58
		Coal	2	1,459.8	1,405.0	33	34	34
		Natural gas	1	5.0	1.0	37	37	37
		Nuclear material	1	1,200.0	1,131.0	22	22	22
		Waste	1	26.0	22.7	15	15	15
		Total	24	2,961.4	2,816.8	23	44	58
	Wind turbine	Wind	3	393.9	393.3	1	4	5
		Total	3	393.9	393.3	1	4	5
	Total	Biomass	19	270.6	257.1	23	49	58
		Coal	2	1,459.8	1,405.0	33	34	34
		Distillate fuel oil	21	34.7	38.5	5	5	5
		Natural gas	48	3,487.9	2,931.9	4	5	13
		Nuclear material	1	1,200.0	1,131.0	22	22	22
		Other gas	11	17.1	16.7	7	7	23
		Waste	1	26.0	22.7	15	15	15
		Water	285	20,900.6	21,391.2	28	46	63
		Wind	3	393.9	393.3	1	4	5
		Total	**391**	**27,790.6**	**27,587.3**	**20**	**38**	**55**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
West Virginia	Combustion (gas) turbine	Natural gas	17	1,464.5	1,288.5	5	5	5
		Other petroleum	1	18.5	12.0	39	39	39
		Total	18	1,483.0	1,300.5	5	5	5
	Hydraulic turbine	Water	19	314.3	254.3	18	70	71
		Total	19	314.3	254.3	18	70	71
	Steam turbine	Coal	35	13,458.5	12,954.0	35	48	55
		Natural gas	1	13.5	2.0	24	24	24
		Other coal	6	1,907.0	1,773.0	14	24	40
		Total	42	15,379.0	14,729.0	33	44	54
	Wind turbine	Wind	1	66.0	66.0	4	4	4
		Total	1	66.0	66.0	4	4	4
	Total	Coal	35	13,458.5	12,954.0	35	48	55
		Natural gas	18	1,478.0	1,290.5	5	5	5
		Other coal	6	1,907.0	1,773.0	14	24	40
		Other petroleum	1	18.5	12.0	39	39	39
		Water	19	314.3	254.3	18	70	71
		Wind	1	66.0	66.0	4	4	4
		Total	**80**	**17,242.3**	**16,349.8**	**6**	**37**	**56**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Wisconsin	Combined cycle	Natural gas	15	2,214.7	2,026.6	1	1	4
		Total	15	2,214.7	2,026.6	1	1	4
	Combustion (gas) turbine	Distillate fuel oil	11	558.0	557.3	28	28	33
		Natural gas	51	3,880.3	3,563.4	6	13	35
		Other gas	5	15.3	14.6	21	21	21
		Total	67	4,453.6	4,135.4	7	21	33
	Hydraulic turbine	Water	227	491.9	474.7	64	82	90
		Total	227	491.9	474.7	64	82	90
	Internal combustion engine	Distillate fuel oil	83	188.3	177.4	7	24	43
		Natural gas	6	24.2	23.2	5	21	36
		Other gas	40	34.7	33.3	4	5	6
		Total	129	247.2	233.9	5	10	36
	Steam turbine	Biomass	12	155.5	153.4	35	55	56
		Coal	55	6,979.2	7,016.0	37	46	55
		Natural gas	5	205.0	210.1	52	52	58
		Nuclear material	3	1,607.7	1,582.0	32	34	36
		Other petroleum	3	38.9	35.4	42	44	76
		Total	78	8,986.3	8,996.8	37	47	55
	Wind turbine	Wind	6	52.6	45.2	7	7	7
		Total	6	52.6	45.2	7	7	7
	Total	Biomass	12	155.5	153.4	35	55	56
		Coal	55	6,979.2	7,016.0	37	46	55
		Distillate fuel oil	94	746.3	734.7	8	28	42
		Natural gas	77	6,324.2	5,823.3	5	12	35
		Nuclear material	3	1,607.7	1,582.0	32	34	36
		Other gas	45	50.0	47.9	4	6	9
		Other petroleum	3	38.9	35.4	42	44	76
		Water	227	491.9	474.7	64	82	90
		Wind	6	52.6	45.2	7	7	7
		Total	**522**	**16,446.3**	**15,912.5**	**16**	**45**	**80**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
Wyoming	Combustion (gas) turbine	Natural gas	13	152.5	116.6	4	4	5
		Other gas	3	108.0	91.8	1	1	1
		Total	16	260.5	208.4	4	4	5
	Hydraulic turbine	Water	25	297.3	301.3	46	54	67
		Total	25	297.3	301.3	46	54	67
	Steam turbine	Coal	23	6,167.8	5,846.9	27	34	43
		Other	1	11.5	11.5	20	20	20
		Total	24	6,179.3	5,858.4	26	33	43
	Wind turbine	Wind	16	287.4	287.4	6	7	7
		Total	16	287.4	287.4	6	7	7
	Total	Coal	23	6,167.8	5,846.9	27	34	43
		Natural gas	13	152.5	116.6	4	4	5
		Other	1	11.5	11.5	20	20	20
		Other gas	3	108.0	91.8	1	1	1
		Water	25	297.3	301.3	46	54	67
		Wind	16	287.4	287.4	6	7	7
		Total	**81**	**7,024.5**	**6,655.5**	**6**	**25**	**47**

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
United States	Combined cycle	Coal	4	630.8	529.0	10	11	32
		Distillate fuel oil	23	816.2	695.3	13	25	37
		Natural gas	1,520	202,092.0	173,651.4	3	6	15
		Other gas	24	245.2	218.8	8	10	14
		Other petroleum	6	399.4	311.8	6	11	17
		Total	1,577	204,183.6	175,406.3	3	6	16
	Combustion (gas) turbine	Distillate fuel oil	561	21,426.6	17,950.4	30	34	36
		Natural gas	2,056	129,006.3	109,218.7	5	11	32
		Other gas	69	733.0	638.0	6	10	17
		Other petroleum	83	2,751.9	2,376.0	34	36	38
		Total	2,769	153,917.8	130,183.1	5	17	35
	Geothermal binary cycle turbine	Geothermal	49	176.7	130.9	14	17	17
		Total	49	176.7	130.9	14	17	17
	Hydraulic turbine	Water	3,725	76,555.0	76,764.8	27	56	82
		Total	3,725	76,555.0	76,764.8	27	56	82
	Internal combustion engine	Biomass	1	2.0	1.8	1	1	1
		Distillate fuel oil	2,061	4,027.5	3,836.5	7	27	43
		Natural gas	659	1,770.4	1,639.8	13	28	43
		Other gas	537	566.8	538.4	6	9	14
		Other petroleum	8	39.2	37.6	17	23	41
		Total	3,266	6,405.9	6,054.1	7	19	40
	Other	Natural gas	1	4.5	3.1	2	2	2
		Other	1	13.0	13.0	42	42	42
		Other gas	4	17.7	12.3	7	7	16
		Other petroleum	2	33.1	28.6	23	30	37
		Waste heat	1	7.5	7.5	23	23	23
		Total	9	75.8	64.5	7	23	25

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
United States (continued)	Photovoltaic	Solar	9	11.0	11.0	5	7	18
		Total	9	11.0	11.0	5	7	18
	Pumped storage hydraulic turbine	Water	150	19,569.3	21,346.6	26	33	39
		Total	150	19,569.3	21,346.6	26	33	39
	Steam turbine	Biomass	249	5,149.6	4,565.8	17	23	41
		Coal	1,291	321,553.7	299,990.3	29	41	51
		Distillate fuel oil	11	936.3	893.0	38	57	59
		Geothermal	163	2,897.7	2,103.3	17	19	20
		Natural gas	562	88,734.9	84,465.9	36	45	51
		Nuclear material	103	104,432.9	98,923.0	20	28	32
		Other	17	415.8	390.3	18	21	36
		Other coal	45	9,063.7	8,484.5	14	20	43
		Other gas	47	1,289.9	1,129.9	17	24	53
		Other petroleum	156	32,222.6	30,453.0	32	42	49
		Purchased steam	5	202.2	161.2	10	27	27
		Solar	9	400.4	399.8	18	19	20
		Waste	90	2,556.9	2,083.0	15	18	20
		Waste heat	11	350.6	318.4	9	14	22
		Total	2,759	570,207.2	534,361.4	23	37	49
	Wind turbine	Wind	267	8,680.9	8,654.1	3	5	9
		Total	267	8,680.9	8,654.1	3	5	9

Mix of Generation Technologies in the United States - 2005

State	Prime Mover	Fuel	Total Number of Units	Total Nameplate Capacity (megawatts)	Total Summer Capacity (megawatts)	Age of Units (years)		
						25th percentile	Median	75th percentile
United States (continued)	Total	Biomass	250	5,151.6	4,567.6	17	23	41
		Coal	1,295	322,184.5	300,519.3	29	41	51
		Distillate fuel oil	2,656	27,206.6	23,375.2	9	32	40
		Geothermal	212	3,074.4	2,234.2	16	18	20
		Natural gas	4,798	421,608.1	368,978.8	5	14	34
		Nuclear material	103	104,432.9	98,923.0	20	28	32
		Other	18	428.8	403.3	18	21	36
		Other coal	45	9,063.7	8,484.5	14	20	43
		Other gas	681	2,852.6	2,537.5	6	9	16
		Other petroleum	255	35,446.2	33,207.0	32	37	45
		Purchased steam	5	202.2	161.2	10	27	27
		Solar	18	411.4	410.8	7	18	20
		Waste	90	2,556.9	2,083.0	15	18	20
		Waste heat	12	358.1	325.9	10	16	23
		Water	3,875	96,124.3	98,111.4	27	54	82
		Wind	267	8,680.9	8,654.1	3	5	9
		Total	**14,580**	**1,039,783.2**	**952,976.8**	**11**	**29**	**47**

Source Data: Department of Energy, Energy Information Agency, Form EIA-860, 2005.
Data available at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

Notes on fuel categories:
"Other coal" includes waste coal, coal-based synfuel, anthracite culm, bituminous gob, fine coal, and lignite waste.
"Other gas" includes blast furnace gas, butane, propane, landfill, other biomass, and gases recovered from other processes.
"Other petroleum" includes jet fuel, kerosene, residual fuel oil, waste oil, liquid propane and butane, and re-refined oil.
"Other" includes batteries, chemicals, hydrogen, tar coal and miscellaneous technologies.

The National Regulatory Research Institute
1080 Carmack Road Columbus, Ohio 43210-1002
Phone: 614-292-0404
Fax: 614-292-1796
www.nrri.ohio-state.edu