Technology Characterization:
Gas Turbines

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Technology Characterization – Gas Turbines

Introduction and Summary

Engineering advancements pioneered the development of gas turbines in the early 1900s, and turbines began to be used for stationary electric power generation in the late 1930s. Turbines revolutionized airplane propulsion in the 1940s, and in the 1990s through today have been a popular choice for new power generation plants in the United States.

Gas turbines are available in sizes ranging from 500 kilowatts (kW) to 250 megawatts (MW). Gas turbines can be used in power-only generation or in combined heat and power (CHP) systems. The most efficient commercial technology for central station power-only generation is the gas turbine-steam turbine combined-cycle plant, with efficiencies approaching 60 percent lower heating value (LHV).[1] Simple-cycle gas turbines for power-only generation are available with efficiencies approaching 40 percent (LHV). Gas turbines have long been used by utilities for peaking capacity. However, with changes in the power industry and advancements in the technology, the gas turbine is now being increasingly used for base-load power.

Gas turbines produce high-quality exhaust heat that can be used in CHP configurations to reach overall system efficiencies (electricity and useful thermal energy) of 70 to 80 percent. By the early 1980s, the efficiency and reliability of smaller gas turbines (1 to 40 MW) had progressed sufficiently to be an attractive choice for industrial and large institutional users for CHP applications.

Gas turbines are one of the cleanest means of generating electricity, with emissions of oxides of nitrogen (NO_x) from some large turbines in the single-digit parts per million (ppm) range, either with catalytic exhaust cleanup or lean pre-mixed combustion. Because of their relatively high efficiency and reliance on natural gas as the primary fuel, gas turbines emit substantially less carbon dioxide (CO_2) per kilowatt-hour (kWh) generated than any other fossil technology in general commercial use.[1]

Applications

The oil and gas industry commonly uses gas turbines to drive pumps and compressors. Process industries use them to drive compressors and other large mechanical equipment, and many industrial and institutional facilities use turbines to generate electricity for use on-site. When used to generate power on-site, gas turbines are often used in combined heat and power mode where energy in the turbine exhaust provides thermal energy to the facility.

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[1] Most of the efficiencies quoted in this report are based on higher heating value (HHV), which includes the heat of condensation of the water vapor in the combustion products. In engineering and scientific literature concerning heat engine efficiencies the lower heating value (LHV – which does not include the heat of condensation of the water vapor in the combustion products) is usually used. The HHV is greater than the LHV by approximately 10% with natural gas as the fuel (e.g., 50% LHV is equivalent to 55% HHV). HHV efficiencies are about 8% greater for oil (liquid petroleum products) and 5% for coal.

[1] Fuel cells, which produce electricity from hydrogen and oxygen, emit only water vapor. There are emissions associated with producing the hydrogen supply depending on its source. However, most fuel cell technologies are still being developed, with only one type (phosphoric acid fuel cell) commercially available in limited production.

There is a significant amount of gas turbine based CHP capacity operating in the United States located at industrial and institutional facilities.[2] Much of this capacity is concentrated in large combined-cycle CHP systems that maximize power production for sale to the grid. However, a significant number of simple-cycle gas turbine based CHP systems are in operation at a variety of applications including oil recovery, chemicals, paper production, food processing, and universities. Simple-cycle CHP applications are most prevalent in smaller installations, typically less than 40 MW.

Gas turbines are ideally suited for CHP applications because their high-temperature exhaust can be used to generate process steam at conditions as high as 1,200 pounds per square inch gauge (psig) and 900 degree Fahrenheit (°F) or used directly in industrial processes for heating or drying. A typical industrial CHP application for gas turbines is a chemicals plant with a 25 MW simple cycle gas turbine supplying base-load power to the plant with an unfired heat recovery steam generator (HRSG) on the exhaust. Approximately 29 MW thermal (MWth) of steam is produced for process use within the plant.

A typical commercial/institutional CHP application for gas turbines is a college or university campus with a 5 MW simple-cycle gas turbine. Approximately 8 MWth of 150 psig to 400 psig steam (or hot water) is produced in an unfired heat recovery steam generator and sent into a central thermal loop for campus space heating during winter months or to single-effect absorption chillers to provide cooling during the summer.

While the recovery of thermal energy provides compelling economics for gas turbine CHP, smaller gas turbines supply prime power in certain applications. Large industrial facilities install simple-cycle gas turbines without heat recovery to provide peaking power in capacity constrained areas, and utilities often place gas turbines in the 5 to 40 MW size range at substations to provide incremental capacity and grid support. A number of turbine manufacturers and packagers offer mobile turbine generator units in this size range that can be used in one location during a period of peak demand and then trucked to another location for the following season.

Technology Description

Basic Process and Components

Gas turbine systems operate on the thermodynamic cycle known as the Brayton cycle. In a Brayton cycle, atmospheric air is compressed, heated, and then expanded, with the excess of power produced by the expander (also called the turbine) over that consumed by the compressor used for power generation. The power produced by an expansion turbine and consumed by a compressor is proportional to the absolute temperature of the gas passing through the device. Consequently, it is advantageous to operate the expansion turbine at the highest practical temperature consistent with economic materials and internal blade cooling technology and to operate the compressor with inlet air flow at as low a temperature as possible. As technology advances permit higher turbine inlet temperature, the optimum pressure ratio also increases.

Higher temperature and pressure ratios result in higher efficiency and specific power. Thus, the general trend in gas turbine advancement has been towards a combination of higher temperatures and pressures. While such advancements increase the manufacturing cost of the

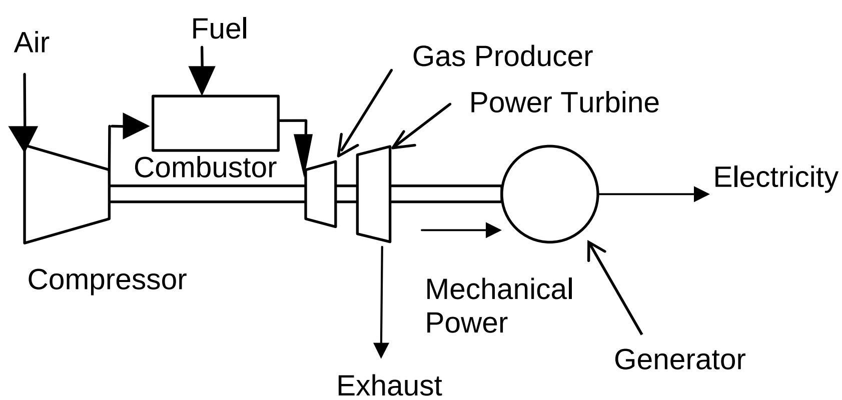
[2] PA Consulting Independent Power Database.

machine, the higher value, in terms of greater power output and higher efficiency, provides net economic benefits. The industrial gas turbine is a balance between performance and cost that results in the most economic machine for both the user and manufacturer.

Modes of Operation

There are several variations of the Brayton cycle in use today. Fuel consumption may be decreased by preheating the compressed air with heat from the turbine exhaust using a recuperator or regenerator; the compressor work may be reduced and net power increased by using intercooling or precooling; and the exhaust may be used to raise steam in a boiler and to generate additional power in a combined cycle. **Figure 1** shows the primary components of a simple cycle gas turbine.

Figure 1. Components of a Simple-Cycle Gas Turbine



Gas turbine exhaust is quite hot, up to 800 to 900°F for smaller industrial turbines and up to 1,100°F for some new, large central station utility machines and aeroderivative turbines. Such high exhaust temperatures permit direct use of the exhaust. With the addition of a heat recovery steam generator, the exhaust heat can produce steam or hot water. A portion or all of the steam generated by the HRSG may be used to generate additional electricity through a steam turbine in a combined cycle configuration.

A gas turbine based system is operating in combined heat and power mode when the waste heat generated by the turbine is applied in an end-use. For example, a simple-cycle gas turbine using the exhaust in a direct heating process is a CHP system, while a system that features all of the turbine exhaust feeding a HRSG and all of the steam output going to produce electricity in a combined-cycle steam turbine is not.

Types of Gas Turbines

Aeroderivative gas turbines for stationary power are adapted from their jet and turboshaft aircraft engine counterparts. While these turbines are lightweight and thermally efficient, they are usually more expensive than products designed and built exclusively for stationary applications. The largest aeroderivative generation turbines available are 40 to 50 MW in capacity. Many aeroderivative gas turbines for stationary use operate with compression ratios in the range of 30:1, requiring a high-pressure external fuel gas compressor. With advanced system developments, larger aeroderivative turbines (>40 MW) are approaching 45 percent simple-cycle efficiencies (LHV).

Industrial or frame gas turbines are exclusively for stationary power generation and are available in the 1 to 250 MW capacity range. They are generally less expensive, more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation with longer inspection and maintenance intervals than aeroderivative turbines. However, they are less efficient and much heavier. Industrial gas turbines generally have more modest compression ratios (up to 16:1) and often do not require an external fuel gas compressor. Larger industrial gas turbines (>100 MW) are approaching simple-cycle efficiencies of approximately 40 percent (LHV) and combined-cycle efficiencies of 60 percent (LHV).

Industry uses gas turbines between 500 kW to 40 MW for on-site power generation and as mechanical drivers. Small gas turbines also drive compressors on long distance natural gas pipelines. In the petroleum industry turbines drive gas compressors to maintain well pressures and enable refineries and petrochemical plants to operate at elevated pressures. In the steel industry turbines drive air compressors used for blast furnaces. In process industries such as chemicals, refining and paper, and in large commercial and institutional applications turbines are used in combined heat and power mode generating both electricity and steam for use on-site.

Design Characteristics

Thermal output:	Gas turbines produce a high quality (high temperature) thermal output suitable for most combined heat and power applications. High-pressure steam can be generated or the exhaust can be used directly for process drying and heating.
Fuel flexibility:	Gas turbines operate on natural gas, synthetic gas, landfill gas, and fuel oils. Plants typically operate on gaseous fuel with a stored liquid fuel for backup to obtain the less expensive interruptible rate for natural gas.
Reliability and life:	Modern gas turbines have proven to be reliable power generators given proper maintenance. Time to overhaul is typically 25,000 to 50,000 hours.
Size range:	Gas turbines are available in sizes from 500 kW to 250 MW.
Emissions:	Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x combustors) that produce NO_x emissions below 25 ppm, with laboratory data down to 9 ppm, and simultaneous low CO emissions in the 10 to 50 ppm range.[3] Selective

[3] Gas turbines have high oxygen content in their exhaust because they burn fuel with high excess air to limit combustion temperatures to levels that the turbine blades, combustion chamber and transition section can handle without compromising system life. Consequently, emissions from gas turbines are evaluated at a reference condition of 15% oxygen. For comparison, boilers use 3% oxygen as the reference condition for emissions, because they can minimize excess air and thus waste less heat in their stack exhaust. Note that due to the different amount of diluent

catalytic reduction (SCR) or catalytic combustion further reduces NO_x emissions. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve single-digit (below 9 ppm) NO_x emissions.

Part-load operation: Because gas turbines reduce power output by reducing combustion temperature, efficiency at part load can be substantially below that of full-power efficiency.

Performance Characteristics

Electrical Efficiency

The thermal efficiency of the Brayton cycle is a function of pressure ratio, ambient air temperature, turbine inlet air temperature, the efficiency of the compressor and turbine elements, turbine blade cooling requirements, and any performance enhancements (i.e., recuperation, intercooling, inlet air cooling, reheat, steam injection, or combined cycle). All of these parameters, along with gas turbine internal mechanical design features, have been improving with time. Therefore newer machines are usually more efficient than older ones of the same size and general type. The performance of a gas turbine is also appreciably influenced by the purpose for which it is intended. Emergency power units generally have lower efficiency and lower capital cost, while turbines intended for prime power, compressor stations and similar applications with high annual capacity factors have higher efficiency and higher capital costs. Emergency power units are permitted for a maximum number of hours per year and allowed to have considerably higher emissions than turbines permitted for continuous duty.

Table 1 summarizes performance characteristics for typical commercially available gas turbine CHP systems over the 1 to 40 MW size range. Heat rates shown are from manufacturers' specifications and industry publications. Available thermal energy (steam output) was calculated from published turbine data on turbine exhaust temperatures and flows. CHP steam estimates are based on an unfired HRSG with an outlet exhaust temperature of 280°F producing dry, saturated steam at 150 psig. Total efficiency is defined as the sum of the net electricity generated plus steam produced for plant thermal needs divided by total fuel input to the system. Higher steam pressures can be obtained but at slightly lower total efficiencies. Additional steam can be generated and total efficiency further increased with duct firing in the HRSG (see heat recovery section). To estimate fuel savings effective electrical efficiency is a more useful value than overall efficiency. Effective electric efficiency is calculated assuming the useful-thermal output from the CHP system would otherwsie be generated by an 80 percent efficient boiler. The theoretical boiler fuel is subtracted from the total fuel input and the remaining fuel input used to calculate the effective electric efficiency which can then be compared to traditional electric generation.

The data in the table show that electrical efficiency increases as combustion turbines become larger. As electrical efficiency increases, the absolute quantity of thermal energy available to produce steam decreases per unit of power output, and the ratio of power to heat for the CHP system increases. A changing ratio of power to heat impacts project economics and may affect the decisions that customers make in terms of CHP acceptance, sizing, and the desirability of selling power.

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gases in the combustion products, the mass of NO_x measured as 9 ppm @ 15% oxygen is approximately 27 ppm @ 3% oxygen, the condition used for boiler NO_x regulations.

Table 1. Gas Turbine CHP - Typical Performance Parameters*

Cost & Performance Characteristics[4]	System 1	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	1,150	5,457	10,239	25,000	40,000
Basic Installed Cost (2007 $/kW)[5]	$3,324	$1,314	$1,298	$1,097	$972
Complex Installation wth SCR (2007 $/kW)[6]	$5,221	$2,210	$1,965	$1,516	$1,290
Electric Heat Rate (Btu/kWh), HHV[7]	16,047	12,312	12,001	9,945	9,220
Electrical Efficiency (percent), HHV	21.27%	27.72%	28.44%	34.30%	37.00%
Fuel Input (MMBtu/hr)	18.5	67.2	122.9	248.6	368.8
Required Fuel Gas Pressure (psig)	82.6	216	317.6	340	435
CHP Characteristics					
Exhaust Flow (1,000 lb/hr)	51.4	170.8	328.2	571	954
GT Exhaust Temperature (Fahrenheit)	951	961	916	950	854
HRSG Exhaust Temperature (Fahrenheit)	309	307	322	280	280
Steam Output (MMBtu/hr)	8.31	28.26	49.10	90.34	129.27
Steam Output (1,000 lbs/hr)	8.26	28.09	48.80	89.8	128.5
Steam Output (kW equivalent)	2,435	8,279	14,385	26,469	37,876
Total CHP Efficiency (percent), HHV[8]	66.3%	69.8%	68.4%	70.7%	72.1%
Power/Heat Ratio[9]	0.47	0.66	0.71	0.94	1.06
Net Heat Rate (Btu/kWh)[10]	7,013	5,839	6,007	5,427	5,180
Effective Electrical Efficiency (percent)[11]	49%	58%	57%	63%	66%

* *For typical systems commercially available in 2007*
Source: Energy and Environmental Analysis, Inc. an ICF Company[5]

Fuel Supply Pressure

[4] Characteristics for "typical" commercially available gas turbine generator system. Data based on: Solar Turbines Saturn 20 – 1 MW; Solar Turbines Taurus 60 – 5 MW; Solar Turbines Mars 100 – 10 MW; GE LM2500+ – 25 MW; GE LM6000PD – 40 MW.
[5] Installed costs based on CHP system producing 150 psig saturated steam with an unfired heat recovery steam generator, no gas compression, no building, no exhaust gas treatment in an uncomplicated installation at a customer site.
[6] Complex installation refers to an installation at an existing customer site with access constraints, complicated electrical, fuel, water, and steam connections requiring added engineering and construction costs. In addition, these costs include gas compression from 55 psig, building, SCR, CO catalyst, and CEMS.
[7] All turbine and engine manufacturers quote heat rates in terms of the lower heating value (LHV) of the fuel. On the other hand, the usable energy content of fuels is typically measured on a higher heating value basis (HHV). In addition, electric utilities measure power plant heat rates in terms of HHV. For natural gas, the average heat content of natural gas is 1,030 Btu/scf on an HHV basis and 930 Btu/scf on an LHV basis – or about a 10% difference.
[8] Total Efficiency = (net electric generated + net steam produced for thermal needs)/total system fuel input
[9] Power/Steam Ratio = CHP electrical power output (Btu)/ useful steam output (Btu)
[10] Net Heat Rate = (total fuel input to the CHP system - the fuel that would be normally used to generate the same amount of thermal output as the CHP system output assuming an efficiency of 80%)/CHP electric output (kW).
[11] Effective Electrical Efficiency = (CHP electric power output)/(Total fuel into CHP system – total heat recovered/0.8); Equivalent to 3,412 Btu/kWh/Net Heat Rate.

Gas turbines need minimum gas pressure of about 100 psig for the smallest turbines with substantially higher pressures for larger turbines and aeroderivative machines. Depending on the supply pressure of the gas being delivered to the site the cost and power consumption of the fuel gas compressor can be a significant consideration. **Table 2** shows the power required to compress natural gas from supply pressures typical of commercial and industrial service to the pressures required by typical industrial gas turbines. Required supply pressures generally increase with gas turbine size.

Table 2. Power Requirements For Natural Gas Compression[12]

	System 1	System 2	System 3	System 4	System 5
Turbine Electric Capacity (kW)	1,000	5,000	10,000	25,000	40,000
Turbine Pressure Ratio	6.5	10.9	17.1	23.1	29.6
Required Compression Power (kW)					
55 psig gas supply pressure	8	82	198	536	859
150 psig gas supply pressure	NA	35	58	300	673
250 psig gas supply pressure	NA	NA	22	150	380

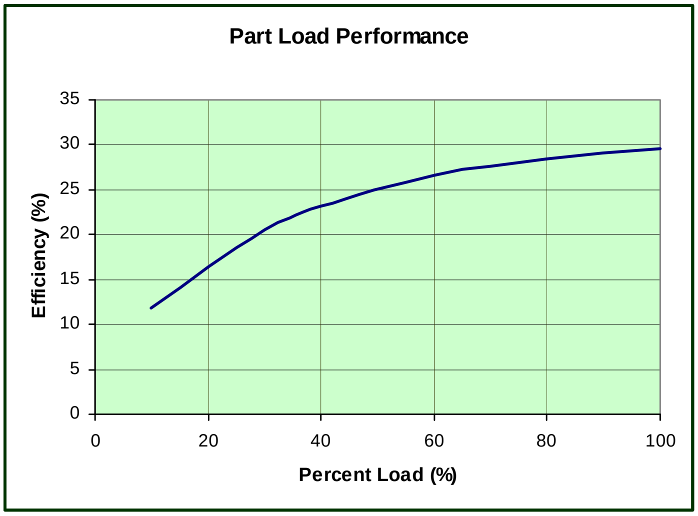
Source: EEA/ICF

Part-Load Performance

When less than full power is required from a gas turbine, the output is reduced by lowering the turbine inlet temperature. In addition to reducing power, this change in operating conditions also reduces efficiency. **Figure 2** shows a typical part-load derate curve. Emissions are generally increased at part load conditions, especially at half load and below.

[12] Fuel gas supply pressure requirements calculated assuming delivery of natural gas at an absolute pressure 35% greater than the compressor discharge in order to meet the requirements of the gas turbine flow control system and combustor mixing nozzles. Mass flow of fuel based on the fuel flow of reference gas turbines in the size range considered, and assuming an electric motor of 95% efficiency driving the booster compressor. Gas supply pressures of 50 psig, 150 psig and 250 psig form the basis of the calculations.

Figure 2. Part Load Power Performance

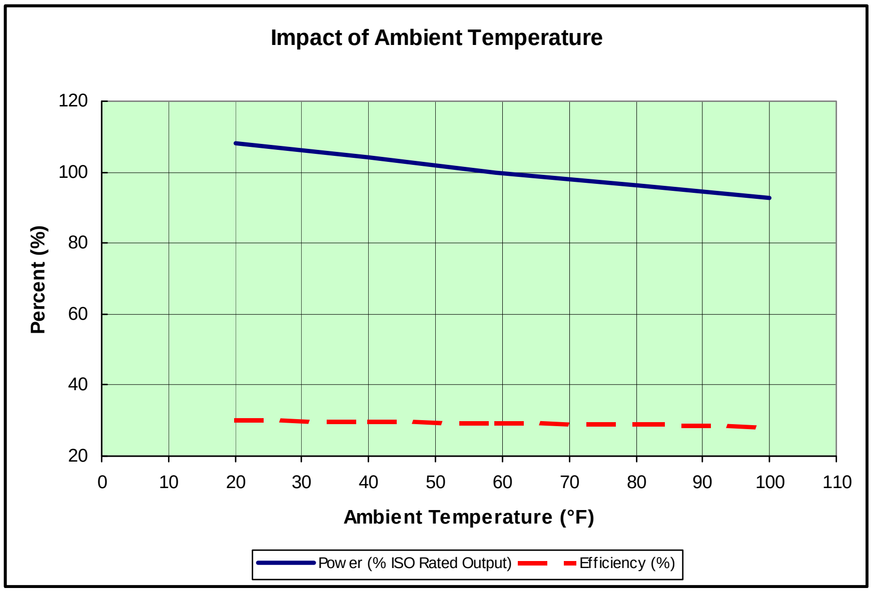


Source: EEA/ICF

Effects of Ambient Conditions on Performance

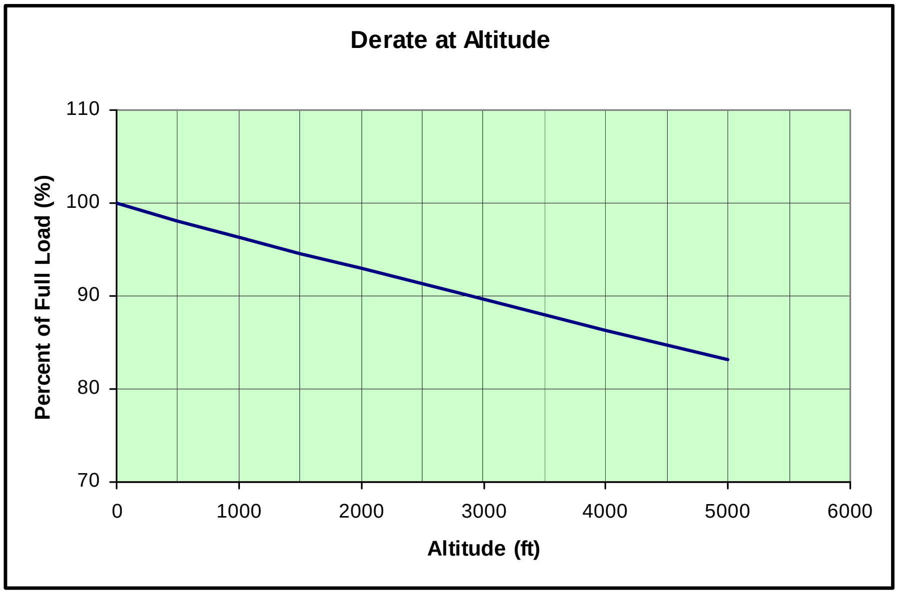
The ambient conditions under which a gas turbine operates have a noticeable effect on both the power output and efficiency. At elevated inlet air temperatures, both the power and efficiency decrease. The power decreases due to the decreased air flow mass rate (the density of air declines as temperature increases) and the efficiency decreases because the compressor requires more power to compress air of higher temperature. Conversely, the power and efficiency increase when the inlet air temperature is reduced. **Figure 3** shows the variation in power and efficiency for a gas turbine as a function of ambient temperature compared to the reference International Organization for Standards (ISO) condition of sea level and 59°F. At inlet air temperatures of near 100°F, power output can drop to as low as 90 percent of ISO-rated power for typical gas turbines. At cooler temperatures of about 40 to 50°F, power can increase to as high as 105 percent of ISO-rated power.

Figure 3. Ambient Temperature Effects on Performance



The density of air decreases at altitudes above sea level. Consequently, power output decreases. The impact of altitude derate is shown in **Figure 4**.

Figure 4. Altitude Effects on Performance

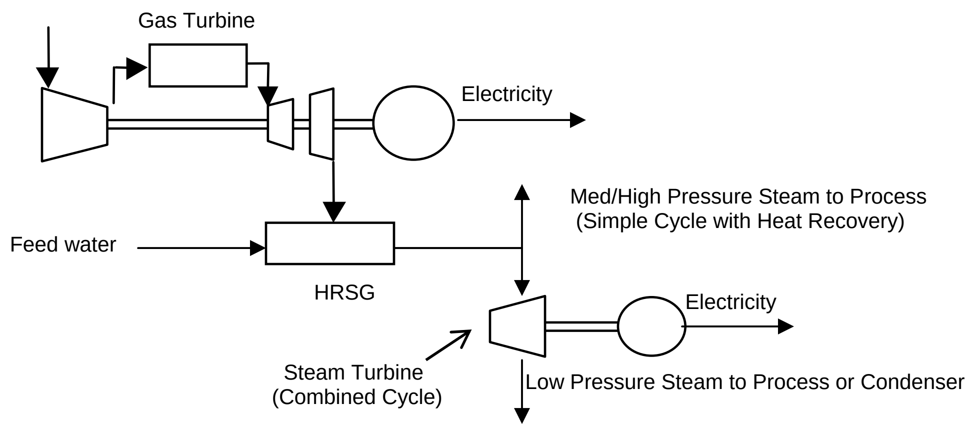


Source: EEA/ICF

Heat Recovery

The economics of gas turbines in process applications often depend on effective use of the thermal energy contained in the exhaust gas, which generally represents 60 to 70 percent of the inlet fuel energy. The most common use of this energy is for steam generation in unfired or supplementary fired heat recovery steam generators. However, the gas turbine exhaust gases can also be used as a source of direct process energy, for unfired or fired process fluid heaters, or as preheated combustion air for power boilers. **Figure 5** shows a typical gas turbine/HRSG configuration. An unfired HRSG is the simplest steam CHP configuration and can generate steam at conditions ranging from 150 psig to approximately 1,200 psig.

Figure 5. Heat Recovery from a Gas Turbine System



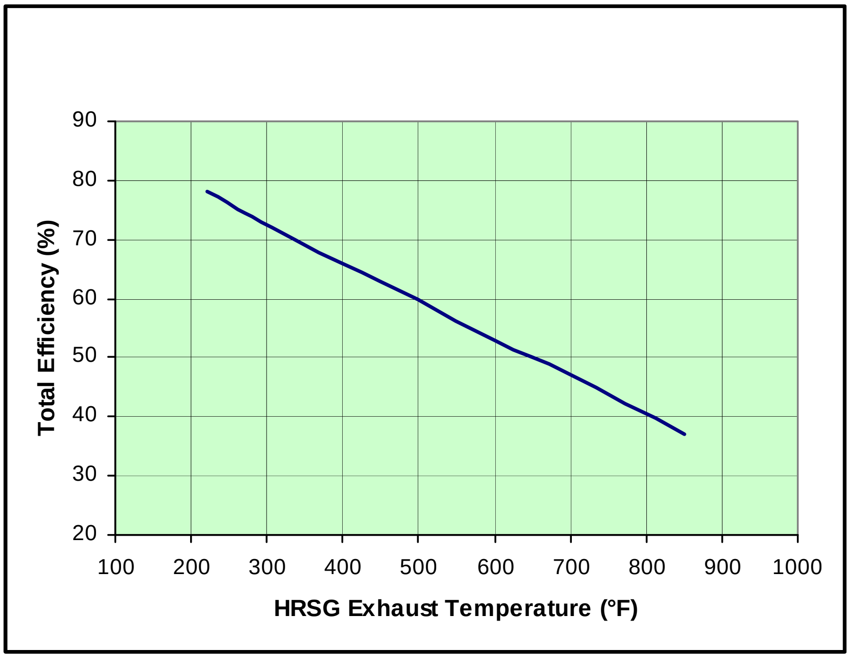
CHP System Efficiency

Overall or total efficiency of a CHP system is a function of the amount of energy recovered from the turbine exhaust. The two most important factors influencing the amount of energy available for steam generation are gas turbine exhaust temperature and HRSG stack temperature.

Turbine firing temperature and turbine pressure ratio combine to determine gas turbine exhaust temperature. Typically aeroderivative gas turbines have higher firing temperatures than do industrial gas turbines, but when the higher pressure ratio of aeroderative gas turbines is recognized, the turbine discharge temperatures of the two turbine types remain somewhat close, typically in the range of 850 to 950°F. For the same HRSG exit temperature, higher turbine exhaust temperature (higher HRSG gas inlet temperature) results in greater available thermal energy and increased HRSG output.

Similarly, the lower the HRSG stack temperature, the greater the amount of energy recovered and the higher the total-system efficiency. HRSG stack temperature is a function of steam conditions and fuel type. Saturated steam temperatures increase with increasing steam pressure. Because of pinch point considerations within the HRSG, higher steam pressures result in higher HRSG exhaust stack temperatures, less utilization of available thermal energy, and a reduction in total CHP system efficiency. In general, minimum stack temperatures of about 300°F are recommended for sulfur bearing fuels. **Figure 6** illustrates the increase in overall system efficiency as the exhaust temperature decreases through effective heat recovery**.** Generally, unfired HRSGs can be designed to economically recover approximately 95 percent the available energy in the turbine exhaust (the energy released in going from turbine exhaust temperature to HRSG exhaust temperature).

Figure 6. Effect of Stack Temperature on Total CHP Efficiency*



** Based on an LM6000 with unfired HRSG*

Overall CHP efficiency generally remains high under part load conditions. The decrease in electric efficiency from the gas turbine under part load conditions results in a relative increase in heat available for recovery under these conditions. This can be a significant operating advantage for applications in which the economics are driven by high steam demand.

Supplementary Firing

Since very little of the available oxygen in the turbine air flow is used in the combustion process, the oxygen content in the gas turbine exhaust permits supplementary fuel firing ahead of the HRSG to increase steam production relative to an unfired unit. Supplementary firing can raise the exhaust gas temperature entering the HRSG up to 1,800°F and increase the amount of steam produced by the unit by a factor of two. Moreover, since the turbine exhaust gas is essentially preheated combustion air, the fuel consumed in supplementary firing is less than that required for a stand-alone boiler providing the same increment in steam generation. The HHV efficiency of incremental steam production from supplementary firing above that of an unfired HRSG is often 85 percent or more when firing natural gas.

Supplementary firing also increases system flexibility. Unfired HRSGs are typically convective heat exchangers that respond solely to exhaust conditions of the gas turbine and do not easily allow for steam flow control. Supplementary firing capability provides the ability to control steam production, within the capability of the burner system, independent of the normal gas turbine operating mode. Low NO_x duct burners with guaranteed emissions levels as low as 0.08 lb NO_x/MMBtu can be specified to minimize the NO_x contribution of supplemental firing.

Performance and Efficiency Enhancements

Recuperators

Several technologies that increase the output power and/or the efficiency of gas turbines have been developed and put into limited commercial service. Fuel use can be reduced (and hence efficiency improved) by use of a heat exchanger called a recuperator that uses the hot turbine exhaust to preheat the compressed air entering the combustor. Depending on gas turbine operating parameters, such a heat exchanger can add up to ten percentage points in machine efficiency (thereby raising efficiency from 30 to 40 percent). However, since there is increased pressure drop in both the compressed air and turbine exhaust sides of the recuperator, power output is typically reduced by 10 to 15 percent.

Recuperators are expensive, and their cost can normally only be justified when the gas turbine operates for a large number of full-power hours per year and the cost of fuel is relatively high. As an example, pipeline compressor station gas turbines frequently operate with high annual capacity factors, and some pipeline gas turbines have utilized recuperators since the 1960s. Recuperators also lower the temperature of the gas turbine exhaust, reducing the turbine's effectiveness in CHP applications. Because recuperators are subject to large temperature differences, they are subject to significant thermal stresses. Cyclic operation in particular can fatigue joints, causing the recuperator to develop leaks and lose power and effectiveness. Design and manufacturing advancements have mitigated some of the cost and durability issues, and commercial recuperators have been introduced on microturbines and on a 4.2 MW industrial gas turbine (through a project supported by the U.S. Department of Energy).

Intercoolers

Intercoolers are used to increase gas turbine power by dividing the compressor into two sections and cooling the compressed air exiting the first section before it enters the second compressor section. Intercoolers reduce the power consumption in the second section of the compressor, thereby adding to the net power delivered by the combination of the turbine and compressor. Intercoolers have been used for decades on industrial air compressors and are used on some reciprocating engine turbochargers. Intercoolers generally are used where additional capacity is particularly valuable. Gas turbine efficiency does not change significantly with the use of intercooling. While intercoolers increase net output, the reduced power consumption of the second section of the compressor results in lower temperature for the compressed air entering the combustor and, consequently, incremental fuel is required.

Inlet Air Cooling

As shown in Figure 4, the decreased power and efficiency of gas turbines at high ambient temperatures means that gas turbine performance is at its lowest at the times power is often in greatest demand and most valued. The figure also shows that cooling the air entering the turbine by 40 to 50°F on a hot day can increase power output by 15 to 20 percent. The decreased power and efficiency resulting from high ambient air temperatures can be mitigated by any of several approaches to inlet-air cooling, including refrigeration, evaporative cooling, and thermal-energy storage using off-peak cooling.

With refrigeration cooling, either a compression driven or thermally activated (absorption chiller) refrigeration cycle cools the inlet air through a heat exchanger. The heat exchanger in the inlet air stream causes an additional pressure drop in the air entering the compressor, thereby slightly lowering cycle power and efficiency. However, as the inlet air is now substantially cooler than the ambient air there is a significant net gain in power and efficiency. Electric motor compression refrigeration requires a substantial parasitic power loss. Thermally activated absorption cooling can utilize waste heat from the gas turbine, reducing the direct parasitic loss. However, the complexity and cost of this approach pose potential drawbacks in many applications.

Evaporative cooling, which is widely used due to its low capital cost, uses a spray of water directly into the inlet air stream. Evaporation of the water reduces the temperature of the air. Since cooling is limited to the wet bulb air temperature, evaporative cooling is most effective when the wet bulb temperature is appreciably below the dry bulb (ordinary) temperature. Evaporative cooling can consume large quantities of water, making it difficult to operate in arid climates. A few large gas turbines have evaporative cooling, and it is expected to be used more frequently on smaller machines in the future.

The use of thermal-energy storage systems, typically ice, chilled water, or low-temperature fluids, to cool inlet air can eliminate most parasitic losses from the augmented power capacity. Thermal energy storage is a viable option if on-peak power pricing only occurs a few hours a day. In that case, the shorter time of energy storage discharge and longer time for daily charging allow for a smaller and less expensive thermal-energy storage system.

Capital Cost

A gas turbine CHP plant is a complex process with many interrelated subsystems. The basic package consists of the gas turbine, gearbox, electric generator, inlet and exhaust ducting, inlet air filtration, lubrication and cooling systems, standard starting system, and exhaust silencing. The basic package cost does not include extra systems such as the fuel-gas compressor, heat-recovery system, water-treatment system, or emissions-control systems such as selective catalytic reduction (SCR) or continuous emission monitoring systems (CEMS). Not all of these systems are required at every site. The cost of the basic turbine package plus the costs for added systems needed for the particular application comprise the total equipment cost. The total plant cost consists of total equipment cost plus installation labor and materials (including site work), engineering, project management (including licensing, insurance, commissioning, and startup), and financial carrying costs during the 6-18 month construction period.

Table 3 details estimated capital costs (equipment and installation costs) for the five typical gas turbine CHP systems**.** These are basic budgetary price levels that do not include building, site work, fuel gas compression, or SCR with a continuous emissions monitoring system. It should be noted that installed costs can vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirements, prevailing labor rates, whether the system is a new or retrofit application, and whether or not the site is a green field or is located at an established industrial site with existing roads, water, fuel, electric, etc. The cost estimates presented in this section are based on systems that include DLE emissions control, unfired heat recovery steam generators (HRSG), water treatment for the boiler feed water, and basic utility interconnection for parallel power generation.

The table shows that there are definite economies of scale for larger turbine power systems. Turbine packages themselves decline in cost only slightly between the range of 5 to 40 MW, but ancillary equipment such as the HRSG, gas compression, water treatment, and electrical equipment are much lower in cost per unit of electrical output as the systems become larger.

Table 3. Estimated Capital Costs for Typical Gas Turbine-Based CHP Systems ($000s)[13]

Cost Component	*System 1*	System 2	System 3	System 4	System 5
Nominal Turbine Capacity (MW)	1	5	10	25	40
Equipment (Thousands of 2007 $)					
Combustion Turbines	$1,015	$2,733	$6,102	$12,750	$23,700
Electrical Equipment	$411	$540	$653	$1,040	$1,575
Fuel System	$166	$177	$188	$251	$358
Water Treatment System	$74	$180	$293	$370	$416
Heat Recovery Steam Generators	$508	$615	$779	$1,030	$1,241
SCR, CO, and CEMS	$0	$0	$0	$0	$0
Building	$0	$0	$0	$0	$0
Total Equipment	$2,173	$4,246	$8,015	$15,440	$27,290
Construction	$769	$1,402	$2,568	$4,947	$8,744
Total Process Capital	$2,942	$5,648	$10,583	$20,387	$36,034
Project/Construction Management	$271	$402	$664	$1,279	$2,260
Shipping	$47	$89	$164	$317	$559
Development Fees	$217	$425	$802	$1,544	$2,729
Project Contingency	$116	$177	$276	$532	$940
Project Financing	$230	$431	$799	$1,540	$2,721
Total Plant Cost	$3,822	$7,172	$13,288	$25,598	$45,243
Actual Turbine Capacity (kW)	1,150	5,457	10,239	23,328	46,556
Total Plant Cost per net kW (2007 $)	$3,324	$1,314	$1,298	$1,097	$972

[13] Combustion turbine costs are based on published specifications and package prices. Installation estimates are based on vendor cost estimation models and developer supplied information.

Table 4 shows a number of cost adders that can make gas turbine power systems more expensive. A cost difference is shown for a "complex" installation that might be characteristic of a retrofit installation at an existing facility with access constraints, special customer conditions, and other factors. Also shown in the table are costs for a building, natural gas compression (from 55 psig, a typical pressure available on distribution mains) and costs for SCR, CO catalyst, and continuous emissions monitoring systems.

Table 4. Capital Cost Adders for Complex Installations and Additional Equipment

Cost Component	*System 1*	System 2	System 3	System 4	System 5
Nominal Turbine Capacity (MW)	1	5	10	25	40
Complex Installation Cost Adder with no additional equipment (2007$ 1000)[14]	$489	$864	$1,551	$2,987	$5,280
Additional Equipment					
Building	n.a.	$311	$414	$576	$759
Compressor Incremental Cost (2007$ 1000)	$416	$937	$1,182	$1,223,500	$1,797,900
Compressor Power Use (kW)	9	90	203	500	1,000
SCR Incremental Cost (2007$ 1000)	$397	$732	$986	$1,350	$1,743
SCR Power Use (kW)	6	29	53	120	225
Equipment Cost Multipliers[15]					
Normal Installation Multiplier	176%	169%	166%	166%	166%
Complex Installation Multiplier	198%	189%	185%	185%	185%
Basic and Complex Cost Estimate Range 2007 $/kW					
Basic Capital Cost 2007 $/kW	$3,324	$1,314	$1,298	$1,097	$972
Complex Installation Capital Cost 2007 $/kW	$5,221	$2,210	$1,965	$1,516	$1,290

An example shows how to use Tables 3 and 4 together. To estimate the cost of a complicated installation of a 5 MW gas turbine with gas compression, a building, and SCR, CO catalyst and CEMS follow the steps below

1. The cost of a basic installation for a nominal 5 MW (5457 kW) turbine is $7,172,000 as shown in Table 3.
2. To convert this basic installation to a complex installation without adding any more equipment add the complex installation adder of $864,000 from Table 4.
3. The additional equipment (building, gas compression, and SCR) from Table 4 total $1,980,000.
4. The equipment cost in step 3 must be multiplied by the complex installation multiplier to arrive at the total installed cost impact of adding this additional equipment. In other words the total impact of adding the equipment is equal to 189 percent of the sum of the equipment added – or $3,742,000.
5. The new capital cost equals 11,778,200 = $7,172,000 + $864,000 + $3,742,000.

[14] This value represents the additional construction, engineering, and other mark-ups that need to be added to the corresponding capital cost estimates in Table 3 to go from a basic installation to a complex installation as previously defined.
[15] These multipliers reflect ratio of design, engineering, construction, shipping, management, and contingency costs to the equipment costs shown. Adding one or more of the equipment shown in the table to a basic installation requires adding the product of added equipment cost times the basic installation multiplier to arrive at the total installed cost impact of adding. For a complex installation, the complex installation multiplier is used instead.

6. The unit cost is equal to the total capital cost divided by the new net output – 5457 kW from Table 3 minus the compression use (90 kW) and the SCR use (29 kW) or \$2,210/kW.

Maintenance

Non-fuel operation and maintenance (O&M) costs presented in **Table 5** are based on gas turbine manufacturer estimates for service contracts, which consist of routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures. The O&M costs presented in Table 5 include operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs, including routine inspections and procedures and major overhauls.

Daily maintenance includes visual inspection by site personnel of filters and general site conditions. Routine inspections are required every 4,000 hours to insure that the turbine is free of excessive vibration due to worn bearings, rotors, and damaged blade tips. Inspections generally include on-site hot gas path boroscope inspections and non-destructive component testing using dye penetrant and magnetic particle techniques to ensure the integrity of components. The combustion path is inspected for fuel nozzle cleanliness and wear, along with the integrity of other hot gas path components.

A gas turbine overhaul is needed every 25,000 to 50,000 hours depending on service and typically includes a complete inspection and rebuild of components to restore the gas turbine to nearly original or current (upgraded) performance standards. A typical overhaul consists of dimensional inspections, product upgrades and testing of the turbine and compressor, rotor removal, inspection of thrust and journal bearings, blade inspection and clearances and setting packing seals.

Gas turbine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions. Although gas turbines can be cycled, cycling every hour triples maintenance costs versus a turbine that operates for intervals of 1,000 hours or more. In addition, operating the turbine over the rated capacity for significant periods of time will dramatically increase the number of hot path inspections and overhauls. Gas turbines that operate for extended periods on liquid fuels will experience higher than average overhaul intervals.

Table 5. Gas Turbine Non-Fuel O&M Costs (Year 2007)

O&M Costs[16]	System 1	System 2	System 3	System 4	System 5
Electricity Capacity, kW	1,000	5,000	10,000	25,000	40,000
Variable (service contract), $/kWh	0.0060	0.0060	0.0060	0.0040	0.0035
Variable (consumables), $/kWh	0.0001	0.0001	0.0001	0.0001	0.0001
Fixed, $/kW-yr	40	10	7.5	6	5
Fixed, $/kWh @ 8,000 hrs/yr	0.0050	0.0013	0.0009	0.0008	0.0006
Total O&M Costs, $/kWh	0.0111	0.0074	0.0070	0.0049	0.0042

Fuels

All gas turbines intended for service as stationary power generators in the United States are available with combustors equipped to handle natural gas fuel. A typical range of heating values of gaseous fuels acceptable to gas turbines is 900 to 1,100 Btu per standard cubic foot (SCF), which covers the range of pipeline quality natural gas. Clean liquid fuels are also suitable for use in gas turbines.

Special combustors developed by some gas turbine manufacturers are capable of handling cleaned gasified solid and liquid fuels. Burners have been developed for medium Btu fuel (in the 400 to 500 Btu/SCF range), which is produced with oxygen-blown gasifiers, and for low Btu fuel (90 to 125 Btu/SCF), which is produced by air-blown gasifiers. These burners for gasified fuels exist for large gas turbines but are not available for small gas turbines.

Contaminants in fuel such as ash, alkalis (sodium and potassium), and sulfur result in alkali sulfate deposits, which impede flow, degrade performance, and cause corrosion in the turbine hot section. Fuels must have only low levels of specified contaminants in them (typically less than 10 ppm total alkalis, and single-digit ppm of sulfur).

Liquid fuels require their own pumps, flow control, nozzles and mixing systems. Many gas turbines are available with either gas or liquid firing capability. In general, gas turbines can convert from one fuel to another quickly. Several gas turbines are equipped for dual firing and can switch fuels with minimal or no interruption.

Lean burn/dry low NO_x gas combustors generate NO_x emissions levels as low as 9 ppm (at 15 percent O_2). Liquid fuel combustors have NO_x emissions limited to approximately 25 ppm (at 15 percent O_2). There is no substantial difference in general performance with either fuel. However, the different heats of combustion result in slightly higher mass flows through the expansion turbine when liquid fuels are used, and thus result in a small increase in power and efficiency performance. In addition, the fuel pump work with liquid fuel is less than with the fuel gas booster compressor, thereby further increasing net performance with liquid fuels.

Gas turbines operate with combustors at pressure levels from 75 to 350 psig. While the pipeline pressure of natural gas is always above these levels, the pressure is normally let down during city gate metering and subsequent flow through the distribution piping system and customer

[16] O&M costs are based on 8,000 operating hours expressed in terms of annual electricity generation. Fixed costs are based on an interpolation of manufacturers' estimates. The variable component of the O&M cost represents the inspections and overhaul procedures that are normally conducted by the prime mover original equipment manufacturer through a service agreement usually based on run hours.

metering. For example, local distribution gas pressures usually range from 30 to 130 psig in feeder lines and from 1 to 60 psig in final distribution lines. Depending on where the gas turbine is located on the gas distribution system, a fuel gas booster compressor may be required to ensure that fuel pressure is adequate for the gas turbine flow control and combustion systems. The cost of such booster compressors adds to the installation capital cost – fuel gas compressor costs can add from $20 to $150/kW to a CHP system's total cost, representing 2 percent of the total cost for a large system up to 10 percent of the total installed cost for a small gas turbine installation.[17] Redundant booster compressors ensure reliable operation because without adequate fuel pressure the gas turbine does not operate.

Availability

Many operational conditions affect the failure rate of gas turbines. Frequent starts and stops incur damage from thermal cycling, which accelerates mechanical failure. Use of liquid fuels, especially heavy fuels and fuels with impurities (alkalis, sulfur, and ash), radiate heat to the combustor walls significantly more intensely than occurs with, clean, gaseous fuels, thereby overheating the combustor and transition piece walls. On the other hand, steady operation on clean fuels can permit gas turbines to operate for a year without need for shutdown. Estimated availability of gas turbines operating on clean gaseous fuels, like natural gas, is in excess of 95 percent.

Emissions

Gas turbines are among the cleanest fossil-fueled power generation equipment commercially available. Gas turbine emission control technologies continue to evolve, with older technologies gradually phasing out as new technologies are developed and commercialized.

The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. Gas turbines operating on desulfized natural gas or distillate oil emit relatively insignificant levels of $SO_{x.}$ In general, SO_x emissions are greater when heavy oils are fired in the turbine. SO_x control is thus a fuel purchasing issue rather than a gas turbine technology issue. Particulate matter is a marginally significant pollutant for gas turbines using liquid fuels. Ash and metallic additives in the fuel may contribute to PM in the exhaust.

It is important to note that the gas turbine operating load has a significant effect on the emissions levels of the primary pollutants of NO_x, CO, and VOCs. Gas turbines typically operate at high loads. Consequently, gas turbines are designed to achieve maximum efficiency and optimum combustion conditions at high loads. Controlling all pollutants simultaneously at all load conditions is difficult. At higher loads, higher NO_x emissions occur due to peak flame temperatures. At lower loads, lower thermal efficiencies and more incomplete combustion occurs resulting in higher emissions of CO and VOCs.

The pollutant referred to as NO_x is a mixture of mostly NO and NO_2 in variable composition. In emissions measurement it is reported as parts per million by volume in which both species count equally. NO_x is formed by three mechanisms: thermal NO_x, prompt NO_x, and fuel-bound NO_x. The predominant NO_x formation mechanism associated with gas turbines is thermal NO_x.

[17] American Gas Association, *Distributed Generation and the Natural Gas Infrastructure,* 1999

Thermal NO_x is the fixation of atmospheric oxygen and nitrogen, which occurs at high combustion temperatures. Flame temperature and residence time are the primary variables that affect thermal NO_x levels. The rate of thermal NO_x formation increases rapidly with flame temperature. Prompt NO_x forms from early reactions of nitrogen modules in the combustion air and hydrocarbon radicals from the fuel. It forms within the flame and typically exists at concentrations of about 1 ppm at 15 percent O_2, and is usually much smaller than the thermal NO_x formation. Fuel-bound NO_x forms when the fuel contains nitrogen as part of the hydrocarbon structure. Natural gas has negligible chemically bound fuel nitrogen.

The control of peak flame temperature, through diluent (water or steam) injection or by maintaining homogenous fuel-to-air ratios that keep local flame temperature below the stoichiometric adiabatic temperature, have been the traditional methods of limiting NO_x formation. In older diffusion flame combustion systems, fuel/air mixing and combustion occurred simultaneously. This resulted in local fuel/air mixture chemical concentrations that produced high local flame temperatures. These high temperature “hot spots” are where most of the NO_x emissions originate. Many new gas turbines feature lean pre-mixed combustion systems. These systems, sometimes referred to as dry low NO_x (DLN) or dry low emissions (DLE), operate in a tightly controlled lean (lower fuel-to-air ratio) premixed mode that maintains modest peak flame temperatures.

CO and VOCs both result from incomplete combustion. CO emissions result when there is insufficient residence time at high temperature. In gas turbines, the failure to achieve CO burnout may result from the quenching effects of dilution and combustor wall cooling air. CO emissions are also heavily dependent on the operating load of the turbine. For example, a gas turbine operating under low loads will tend to have incomplete combustion, which will increase the formation of CO. CO is usually regulated to levels below 50 ppm for both health and safety reasons. Achieving such low levels of CO had not been a problem until manufacturers achieved low levels of NOx, because the techniques used to engineer DLN combustors had a secondary effect of increasing CO emissions.

VOCs can encompass a wide range of compounds, some of which are hazardous air pollutants. These compounds discharge into the atmosphere when some portion of the fuel remains unburned or just partially burned. Some organics are unreacted trace constituents of the fuel, while others may be pyrolysis products of the heavier hydrocarbons in the gas.

Emissions of carbon dioxide (CO_2) are also of concern due to its contribution to global warming. Atmospheric warming occurs because solar radiation readily penetrates to the surface of the planet but infrared (thermal) radiation from the surface is absorbed by the CO_2 (and other polyatomic gases such as methane, unburned hydrocarbons, refrigerants, water vapor, and volatile chemicals) in the atmosphere, with resultant increase in temperature of the atmosphere. The amount of CO_2 emitted is a function of both fuel carbon content and system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/MMBtu; oil is 48 lbs carbon/MMBtu; and (ash-free) coal is 66 lbs carbon/MMBtu.

Emissions Control Options

NO_x control has been the primary focus of emission control research and development in recent years. The following provides a description of the most prominent emission control approaches:

Diluent Injection

The first technique used to reduce NO_x emissions was injection of water or steam into the high temperature flame zone. Water and steam are strong diluents and can quench hot spots in the flame reducing NO_x. However, because positioning of the injection is not precise some NO_x is still created. Depending on uncontrolled NO_x levels, water or steam injection reduces NO_x by 60 percent or more. Water or steam injection enables gas turbines to operate with NO_x levels as low as 25 ppm (@ 15 percent O_2) on natural gas. NO_x is only reduced to 42 to 75 ppm when firing with liquid distillate fuel. Both water and steam increase the mass flow through the turbine and create a small amount of additional power. Use of exhaust heat to raise the steam temperature also increases overall efficiency slightly. The water used needs to be demineralized thoroughly in order to avoid forming deposits and corrosion in the turbine expansion section. This adds cost and complexity to the operation of the turbine. Diluent injection increases CO emissions appreciably as it lowers the temperature in the burnout zone, as well as in the NO_x formation zone.

Lean Premixed Combustion

As discussed earlier, thermal NO_x formation is a function of both flame temperature and residence time. The focus of combustion improvements of the past decade was to lower flame hot spot temperature using lean fuel/air mixtures. Lean combustion decreases the fuel/air ratio in the zones where NO_x production occurs so that peak flame temperature is less than the stoichiometric adiabatic flame temperature, therefore suppressing thermal NO_x formation.

Lean premixed combustion (DLN/DLE) pre-mixes the gaseous fuel and compressed air so that there are no local zones of high temperatures, or "hot spots," where high levels of NO_x would form. Lean premixed combustion requires specially designed mixing chambers and mixture inlet zones to avoid flashback of the flame. Optimized application of DLN combustion requires an integrated approach to combustor and turbine design. The DLN combustor becomes an intrinsic part of the turbine design, and specific combustor designs must be developed for each turbine application. While NO_x levels as low as 9 ppm have been achieved with lean premixed combustion, few DLN equipped turbines have reached the level of practical operation at this emissions level necessary for commercialization – the capability of maintaining 9 ppm across a wide operating range from full power to minimum load. One problem is that pilot flames, which are small diffusion flames and a source of NO_x, are usually used for continuous internal ignition and stability in DLN combustors and make it difficult to maintain full net NO_x reduction over the complete turndown range.

Noise can also be an issue in lean premixed combustors as acoustic waves form due to combustion instabilities when the premixed fuel and air ignite. This noise also manifests itself as pressure waves, which can damage combustor walls and accelerate the need for combustor replacement, thereby adding to maintenance costs and lowering unit availability.

All leading gas turbine manufacturers feature DLN combustors in parts of their product lines. Turbine manufacturers generally guarantee NO_x emissions of 15 to 42 ppm using this technology. NO_x emissions when firing distillate oil are typically guaranteed at 42 ppm with DLN and/or combined with water injection. A few models (primarily those larger than 40 MW) have combustors capable of 9 ppm (natural gas fired) over the range of expected operation.

The development of market-ready DLN equipped turbine models is an expensive undertaking because of the operational difficulties in maintaining reliable gas turbine operation over a broad power range. Therefore, the timing of applying DLN to multiple turbine product lines is a function of market priorities and resource constraints. Gas turbine manufacturers initially develop DLN combustors for the gas turbine models for which they expect the greatest market opportunity. As time goes on and experience is gained, the technology is extended to additional gas turbine models.

Selective Catalytic Reduction

The primary post-combustion NO_x control method in use today is selective catalytic reduction (SCR). Ammonia is injected into the flue gas and reacts with NO_x in the presence of a catalyst to produce N_2 and H_2O. The SCR system is located in the exhaust path, typically within the HRSG where the temperature of the exhaust gas matches the operating temperature of the catalyst. The operating temperature of conventional SCR systems ranges from 400 to 800°F. The cost of conventional SCR has dropped significantly over time -- catalyst innovations have been a principal driver, resulting in a 20 percent reduction in catalyst volume and cost with no change in performance.

Low temperature SCR, operating in the 300 to 400°F temperature range, was commercialized in 1995 and is currently in operation on approximately twenty gas turbines. Low temperature SCR is ideal for retrofit applications where it can be located downstream of the HRSG, avoiding the potentially expensive retrofit of the HRSG to locate the catalyst within a hotter zone of the HRSG.

High temperature SCR installations, operating in the 800 to 1,100°F temperature range, have increased significantly in recent years. The high operating temperature permits the placement of the catalyst directly downstream of the turbine exhaust flange. High temperature SCR is also used on peaking capacity and base-loaded simple-cycle gas turbines where there is no HRSG.

SCR reduces between 80 to 90 percent of the NO_x in the gas turbine exhaust, depending on the degree to which the chemical conditions in the exhaust are uniform. When used in series with water/steam injection or DLN combustion, SCR can result in low single digit NO_x levels (2 to 5 ppm).

SCR systems are expensive and significantly impact the economic feasibility of smaller gas turbine projects. For a 5 MW project electric generation costs increase approximately half a cent per kWh.[18] SCR requires on-site storage of ammonia, a hazardous chemical. In addition, ammonia can “slip” through the process unreacted, contributing to environmental health concerns.[19]

Carbon Monoxide Oxidation Catalysts

Oxidation catalysts control CO in gas turbine exhaust. Some SCR installations incorporate CO oxidation modules along with NO_x reduction catalysts for simultaneous control of CO and NO_x. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide

[18] *Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines*, ONSITE SYCOM Energy Corporation, November, 1999.

[19] The SCR reaction, with stoichiometric (for NO_x reduction) ammonia or other reagent should eliminate all NO_x. However because of imperfect mixing in the combustor the NO_x is not uniformly distributed across the turbine exhaust. Additionally, the ammonia, or other reagent, also is not injected in a precisely uniform manner. These two non-uniformities in chemical composition cause either excess ammonia to be used, and to consequently "slip" out the exhaust, or for incomplete reaction of the NO_x in the turbine exhaust.

(CO_2) and water (H_20) as the exhaust stream passes the through the catalyst bed. The oxidation process takes place spontaneously so no reactants are required. The catalyst is usually made of precious metal such as platinum, palladium, or rhodium. Other formations, such as metal oxides for emission streams containing chlorinated compounds, are also used. CO catalysts also reduce VOCs and organic hazardous air pollutants (HAPs). CO catalysts on gas turbines result in approximately 90 percent reduction of CO and 85 to 90 percent control of formaldehyde (similar reductions can be expected on other HAPs).

Catalytic Combustion

In catalytic combustion, fuels oxidize at lean conditions in the presence of a catalyst. Catalytic combustion is a flameless process, allowing fuel oxidation to occur at temperatures below 1,700°F, where NO_x formation is low. The catalyst is applied to combustor surfaces, which cause the fuel air mixture to react with the oxygen and release its initial thermal energy. The combustion reaction in the lean premixed gas then goes to completion at design temperature. Data from ongoing long term testing indicates that catalytic combustion exhibits low vibration and acoustic noise, only one-tenth to one-hundredth the levels measured in the same turbine equipped with DLN combustors.

Gas turbine catalytic combustion technology is being pursued by developers of combustion systems and gas turbines and by government agencies, most notably the U.S. Department of Energy and the California Energy Commission. Past efforts at developing catalytic combustors for gas turbines achieved low, single-digit NO_x ppm levels, but failed to produce combustion systems with suitable operating durability. This was typically due to cycling damage and to the brittle nature of the materials used for catalysts and catalyst support systems. Catalytic combustor developers and gas turbine manufacturers are testing durable catalytic and “partial catalytic” systems that are overcoming the problems of past designs. Catalytic combustors capable of achieving NO_x levels below 3 ppm are in full-scale demonstration and are entering early commercial introduction.[20] Similarly to DLN combustion, optimized catalytic combustion requires an integrated approach to combustor and turbine design. Catalytic combustors must be tailored to the specific operating characteristics and physical layout of each turbine design.

Catalytic Absorption Systems

SCONOx™, patented by Goaline Environmental Technologies (currently EmerChem), is a post-combustion alternative to SCR that reduces NOx emissions to less than 2.5 ppm and almost 100 percent removal of CO. SCONOx™ combines catalytic conversion of CO and NOx with an absorption/regeneration process that eliminates the ammonia reagent found in SCR technology. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO catalytically oxidize to CO_2 and NO_2. The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOx™ catalyst. The system does not require the use of ammonia, eliminating the potential for ammonia slip associated with SCR. The SCONOx™ system is generally located within the HRSG and under special circumstances may be located downstream of the HRSG. The system operates between 300-700ºF. U.S. EPA Region 9 identified SCONOx™ as “Lowest Achievable Emission Rate (LAER)” technology for gas turbine NO_x control in 1998.

[20] For example, Kawasaki offers a version of their M1A 13X, 1.4 MW gas turbine with a catalytic combustor with less than 3 ppm NOx guaranteed.

The SCONOx™ technology is still in the early stages of market introduction. Issues that may impact application of the technology include relatively high capital cost, large reactor size compared to SCR, system complexity, high utilities cost and demand (steam, natural gas, compressed air and electricity are required), and a gradual rise in NO emissions over time that requires a 1 to 2 day shutdown every 6 to 12 months (depending on fuel quality and operation) to remove and regenerate the absorption modules ex-situ.[21]

Gas Turbine Emissions Characteristics

Table 6 shows typical emissions for each of the five typical turbine systems for the base year (2000). Typical emissions presented are based on gas turbine exhaust with no exhaust treatment and reflect what manufacturers will guarantee. Notable outliers for specific installations or engine models are identified. Due to the uniqueness of the combustion system of each gas turbine model, clear distinctions need to be made when discussing emissions technology and the corresponding emissions levels. Those distinctions are technology that is commercially available, technology that is technically proven but not yet commercial, and technology that is technically feasible but neither technically proven nor commercially available. This is particularly true for pollution prevention and combustion technologies as opposed to exhaust treatment control alternatives.

Add-on control options for NO_x and CO can further reduce emissions of each by 80 to 90 percent. For many distributed generation gas turbine installations, exhaust treatment options have for the most part been avoided or not implemented due to the unfavorable capital and operating costs impacts.

Table 6. Gas Turbine Emissions Characteristics without Heat Recovery or Exhaust Control Options*

Emissions Characteristics	System 1	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	1,000	5,000	10,000	25,000	40,000
Electrical Efficiency (HHV)	21.9%	27.1%	29.0%	34.3%	37.0%
NO_x, ppm	42	15	15	25	15
NO_x, lb/MWh[22]	2.43	0.66	0.65	0.90	0.50
CO, ppmv[23]	20	25	25	25	25
CO, lb/MWh[23]	0.71	0.68	0.66	0.55	0.51
CO_2, lb/MWh	1,877	1,440	1,404	1,163	1,079
Carbon, lb/MWh	512	393	383	317	294

* *For typical systems commercially available in 2007. Emissions estimates for untreated turbine exhaust conditions (15 percent O_2, no SCR or other exhaust clean up). Estimates based on typical manufacturers' guarantees using commercially available dry low NOx combustion technology.*

[21] Resource Catalysts, Inc.
[22] Conversion from volumetric emission rate (ppm at 15% O_2) to output based rate (lbs/MWh) for both NO_x and CO based on conversion multipliers provided by Catalytica Energy Systems (*http://www.catalyticaenergy.com/xonon/emissions_factors.html*).
[23] CO catalytic oxidation modules on gas turbines result in approximately 90% reduction of CO. Recent permits have included the utilization of CO catalysts to achieve less than 5 ppm CO.