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8.6 Liquid/Gas-Fueled Technologies

8.6.1 Combustion Turbines and Combined Cycle

Technology Status

Combustion turbines (CT) and combustion turbines with a steam generation bottoming cycle or combined cycle (CC) are of interest due to

- Favorable natural gas price and supply
- Increased demand for new peaking- and cycling-load power generation capacity
- Improved efficiency and emission performance of the new higher firing temperature combustion turbines
- Increased vendor competition in the markets for heavy-duty and aeroderivative combustion turbines
- Much higher power-to-cogen heat ratio than in a steam cycle.

Table 8-25 is a technology monitoring guide of the leading developers and technical issues in CT and CC based power plant technology. Much of the current effort is focused on long-term performance and availability of new higher firing temperature (2300°F) CTs in commercial applications. There is also a major effort in the commercialization of the new "dry" low NO_x burners for these same turbines.

Table 8-26 is a development "map" for CT and CC power plant technology. First-generation CTs are ideal for peaking-load applications where low capital cost and high availability have a much greater impact than performance. The improved performance of the second-generation turbines is more significant in combined-cycle configurations for cycling- and base-load applications. The key issue for these new commercially available second-generation combustion turbines is long-term performance and availability. Along with higher firing temperatures, the advanced combustion turbines also include equipment modifications such as compressor intercooling, advanced blade cooling, reheating and recuperators as well as cycle modifications, such as air storage and air humidification.

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Table 8-25
Technology Monitoring Guide

Combustion Turbines and Combined Cycle

		Leading Developers of the Science or Technologies						
Technologies	R & D Intensity[a]	Government Organizations	Nonprofit Organizations	Industrial Firms	Leading Vendors	Major Trends	Changes To Watch For	Unresolved Issues
2000°F conventional combustion turbines	Low	—	EPRI	—	ABB C-E General Electric Siemens/KWU United Technology	Improved controls and maintenance	Lower-NO_x burners, adding steam cycle to increase capacity and/or performance	Modification of existing or replacement of CT for improved performance
2300°F heavy-duty combustion turbines	High	—	EPRI	Virginia Power Florida P&L	ABB C-E General Electric MHI/Westinghouse Siemens/KWU	Uprated capacity and performance, strong competition	Use in peaking-load applications, improved "dry" low-NO_x burners	Long-term performance and availability
2300°F aeroderivative combustion turbines	High	—	—	Steward & Stevenson TransAlta	General Electric Rolls Royce/West. United Technology	Increased competition	Reduced cost plus uprated capacity and performance	Long-term performance and availability
2500°F advanced combustion turbines	Moderate	DOE DOD	EPRI		All of above	Low energy prices limit incentives for development	Increase in natural gas prices	High cost of development and modification

(a) Based on the amount of R&D investments and/or new published information.

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Table 8-26
Technology Process Development "Map"

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Combustion Turbines and Combined Cycle

	Generations/Major Changes			
	First	Second	Second	Third
Process identification	Conventional combustion turbines	Heavy-duty combustion turbines	Aeroderivative combustion turbines	Advanced combustion turbines
Firing temperature, °F	2000	2300	2300	2500
Major features & advantages				
Environmental	- Moderate NO_x via steam injection	- Moderate NO_x via steam injection and dry low NO_x	- Low NO_x via massive* steam injection (STIG)	- Low NO_x via "dry" air premixing/staging
Others	- Extensive operating experience in peaking-load applications	- Improved controls and maintenance - Good operating experience in base and cycling load - Large size	- Improved controls and maintenance - Good operating experience in industrial cogeneration application - High CT efficiency - Good part-load performance	- Higher efficiency - Potential modifications include: intercooling, reheating, recuperators, water/steam cooling, and air humidification
Efficiency, % (HHV) @ ISO conditions	CT - 28 CC - 43	CT - 30 CC - 46	CT - 34 STIG-37 CC - 44	Aeroderivative CT - 40 Heavy Duty CC - 50+
Relative capital cost	CT - Very low CC - Low	CT - Very low CC - Low	CT - Low CC or STIG - Moderate	CT - Low CC - Moderate
Target busbar cost 1992 basis, cents/kWh	N/A	N/A	N/A	N/A
Major disadvantages				
Environmental	- NO_x limitations	- NO_x limitations	- NO_x for liquid fuels	- NO_x for both higher temp. and liquid fuels
Others		- Limited experience in peaking applications - Limited long-term availability data - Limited to large size	- Limited experience in utility applications - Limited long-term availability data - Limited to small size	- Demonstration of long-term availability data
Key technology needs	- Improved NO_x control - Improved controls and maintenance	- Improved NO_x control - Long-term performance and availability	- NO_x for liquid fuels - Long-term performance and availability	- Improved NO_x control - Improved controls and maintenance
Development timeframe				
Research	1960–70	1980–1985	1980–1985	1985–1990
Development	1970–75	1985–1988	1985–1988	1990–1995
Demonstration	1975–80	1988–1991	1988–1991	1995–2000
Commercialization date	1980	1990	1990	2000
Key issues	- Improved performance and availability	- Long-term performance and availability - CC efficiency and part-load performance	- Long-term performance and availability - CT only efficiency and part-load performance	- High cost of CT development/modifications - Current low energy limits economic benefits - Demonstration of performance and availability

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Combustion Turbines and Combined Cycle

Design Description

Simple-Cycle Combustion Turbine Generator

A combustion turbine (CT), also called a gas turbine (GT), includes an air compressor, a combustor, and an expansion turbine. Gaseous or liquid fuels are burned under pressure at about 10 atm in the combustor, producing hot gases that pass through the expansion turbine, driving the air compressor. The shaft of the CT is coupled to an electric generator such that mechanical energy produced by the CT drives the electric generator.

A simple-cycle CT is one in which the working fluid remains gaseous throughout the cycle, which consists of adiabatic compression, isobaric heating, and isentropic expansion and isobaric cooling. In some cases simple-cycle CTs in conjunction with heat recovery steam generators (HRSGs) are used to produce steam. In this configuration all of the steam produced is used for process purposes such as in a refinery, for enhanced oil recovery, or in a steam-injected gas turbine (STIG) cycle which is described below.

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The major emissions from CTs are nitrogen oxides (NO_x). NO_x emissions have been controlled by injecting water or steam into the combustor. Several manufacturers offer dry low NO_x (DLN) combustors commercially, where low levels of NO_x are being achieved without having to inject water or steam.

The power output of the combustion turbine is very sensitive to ambient temperature. Maximum power typically drops about 0.4% for each degree Fahrenheit increase in ambient temperature. For example, General Electric's new 7FA CT has an output rating of about 160 MW at 59°F ambient temperature, sea level elevation. This rated output drops to about 140 MW at 90°F ambient. The reference site conditions (ISO) for data presented are 59°F, 60% relative humidity, and sea level elevation.

Turbine efficiency is strongly influenced by the expansion turbine inlet temperature. Until recently, CTs for stationary applications (heavy duty) had maximum inlet temperatures of approximately 2000°F. The new generation of advanced design CTs have turbine inlet temperatures as high as 2350°F. This higher inlet temperature reduces the heat rate by about 10%.

The aeroderivative gas turbine is a jet engine that has been modified or adapted for stationary industrial use. The result is a lightweight durable package with attractive efficiencies in simple-cycle service.

Current CT technology includes automatically controlled compressor inlet guide vanes (IGVs), which permit control of the volume (mass flow) of inlet air flow leading to the capability of part-load operation at essentially full-load operating efficiency (heat rate) down to typically 80% output. Currently operating nonutility generators (NUGs) and utility plants using CT technology are achieving very reliable operation with CT operating availabilities in the mid-90% range. Advanced design CTs are in the early stage of operation and also anticipate achieving long-term reliable operation with high CT operating availability.

The key features of simple-cycle CTs include flexibility in siting, low emission levels with natural gas fuel, low capital cost, and short construction time. These advantages make them attractive for peaking duty applications. Peak duty simple-cycle plot arrangements can be designed to allow for later conversion to combined cycle through staged development. The key issues include long-term natural gas availability, transportation, and pricing.

Cost and performance data for simple-cycle, heavy-duty CTs are presented in **Exhibits 19 and 20**; aero CTs are presented in **Exhibit 21**. Simple-cycle CTs are assumed to be in peak duty operation, with annual capacity factors at 10%. Emissions licensing for NO_x is assumed to be at 25 ppmvd, without the requirement for selective catalytic reduction (SCR).

Steam-Injected Gas Turbine (STIG)

A steam-injected gas turbine (STIG) is a simple-cycle CT application where combustion gases are passed through a heat recovery steam generator (HRSG), which heats pressurized water to generate superheated steam. This steam is injected back into the gas turbine itself rather than into a bottoming-cycle steam turbine, as in a combined-cycle system. Most of the steam is injected into the combustor region of the gas turbine, where it is mixed with the combustor air and heated to the turbine inlet temperature.

STIG generating units do not require condensers or cooling towers to support a bottoming cycle. Although the injected steam is heated to the turbine inlet temperature in the combustor, its expansion ratio is limited to that of the compressor section surge, and the quantity of steam is limited to the turbine's swallowing area.

Several varieties of STIG turbines in the range of 1 to 50 MW are in operation and are currently being marketed. These installations are being operated as NUGs in the United States and by private parties abroad. Most STIG units are aeroderivatives and include the General Electric LM 5000-120 STIG, which has the best heat rate of the STIG units. At 50 MW, this CT also comes closest to the unit size of interest to utilities.

Air emissions from STIG units have similar NO_x emissions compared with the combined-cycle units since both could use either steam injection or DLN combustion system. Data presented assume that the STIG unit will be used for intermediate operation of not more than 2700 hours of annual operation. In such duty it is assumed that NO_x emissions will be lowered to 25 ppmvd, without the requirement for an SCR. Should the STIG unit be considered for duty beyond 2700 h/yr (varies based on local regulatory commissions), an SCR could be required to lower NO_x emissions to single digit, 9 ppmvd.

The consumptive water required for the STIG cycle could be an issue in many geographical areas. The LM 5000-120 STIG refers to the requirement that approximately 120,000 lb/h of steam is required for injection into the CT. This steam is then consumed and is released through the exhaust stack. Makeup water for the HRSG must be 100% demineralized water treated to comply with the CT manufacturer's specification for water purity. Steam purity and carryover must also meet the CT manufacturer's requirements.

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Automatic control of the CT IGVs offers the capability of part-load operation at essentially full-load operating efficiency (heat rate) down to typically 80% output.

Key features of the STIG cycle include cases where peaking duty requires excellent operating efficiency and low emission levels with natural gas fuel. STIG is also considered for possible intermediate duty, where the STIG technology is a competitor to the more established combined-cycle technology. Key issues are the supply and treatment of the consumptive water and the resulting exhaust plume incursion. Visible plumes would travel long distances under very stable atmospheric conditions.

Cost and performance data for the STIG-cycle aeroderivative CTs are presented in **Exhibit 22**. These data assume that STIG CTs are used in intermediate duty operation (capacity factors of 30%).

Combined-Cycle Combustion Turbine

The first gas turbine installed in an electric utility in the United States was applied in a combined-cycle configuration. This was a 3.5-MW CT that used the energy from the exhaust gas to heat feedwater for a 35-MW conventional steam unit. This system entered service in 1949 in the Oklahoma Gas and Electric Company Belle Isle Station. Continuing manufacturer research and operator experience have now resulted in a reliable, highly efficient combined-cycle plant that is, in many cases, the cycle chosen to meet new intermediate and baseload needs.

In a CT combined cycle (CTCC) the hot exhaust gases from the CT pass through a HRSG, where they are cooled to between 250 and 300°F, and in so doing, produce steam. Conventional CT exhaust gases are at about 1000°F, while advanced CTs produce about 1100°F exhaust gas. Typical steam conditions from the HRSG are 700–1500 psig and 900–1000°F. The steam drives a steam turbine generator (STG), which provides the bottoming cycle. Usually about two-thirds of the power is produced from the CTs, and one-third from the STG. Advanced CT exhaust temperatures, in most cases, lead to the selection of a reheat STG cycle.

In cases where the simple-cycle CT plant's plot plan has been given proper consideration, the steam turbine bottoming cycle may be added to the plant, resulting in a second stage of construction and producing a combined-cycle plant. Combined-cycle plants may operate with both conventional and advanced CTs. Both cases are presented. With the higher exhaust temperature of the advanced CT, the steam-bottoming cycle efficiency is increased by adding a single-reheat stage to the STG.

The site conditions used (ISO) for the data presented are 59°F, 60% relative humidity, sea level.

Combined-cycle plant operation is assumed to be either intermediate (20–50% capacity factor) between 1750 and 4380 h/yr or baseload (50–85% capacity factor) between 4380 and 7450 h/yr. Operation and maintenance data presented assume an annual combined-cycle capacity factor of 65%.

Air emission licensing throughout the United States has evolved such that new plants most likely will require single-digit NO_x and possibly single-digit CO emissions. Data presented assume CT emissions of 25 ppmvd for NO_x are achieved by steam injection or a DLN combustion system. An SCR is included to reduce NO_x emission levels to 9 ppmvd. No catalyst is included for CO emission reduction. Current CT manufacturer DLN combustor development programs, when fully developed in later years, may prove to be adequate for producing single-digit NO_x emissions without the use of SCR.

The key features of combined-cycle plants include a track record provided by NUG and utility plants indicating high reliability and operating availability in the mid-90% range, reasonable capital costs, excellent operating efficiency, low emission levels, possibility of staged construction, and shorter construction cycles than for solid fuel plants.

The key issues include long-term natural gas availability, transportation, and pricing.

Several current technical papers describe the performance of various fleets of combined-cycle plants. Each paper describes high plant reliability, achieving expected operating efficiency and high plant availability (1–4).

Cost and performance data for the heavy-duty combined-cycle plants are presented in **Exhibit 23**. CTCCs are assumed to be in baseload duty operation, at a 65% annual capacity factor.

Combustion Turbine Performance Considerations. With respect to site elevation, the performance of a simple-cycle CT is dependent upon the mass flow of air to the compressor. Data presented here assume ISO conditions of 59°F, 60% relative humidity, at sea level. The correction for performance due to altitude is based upon less dense air at higher elevations reducing the mass flow of air through the compressor resulting in a proportional drop in output. Altitude has no effect on simple-cycle CT heat rate or other cycle factors.

Figure 8-28, Simple-Cycle Altitude Correction Curve, is generic for any simple cycle CT. The same altitude correction factor applied to the reduction in gross CT output can also be used as the approximate reduction in CT fuel consumed, and since less steam will be produced, it can also be used to approximate the reduction in gross steam turbine output of a combined-cycle plant.

Data presented are based on the ISO temperature of 59°F as the temperature at the compressor inlet. Higher temperatures result in less dense air, and lower temperatures result in more dense air. **Figure 8-29**, Simple-Cycle Compressor Inlet Temperature Curve, provides a correction factor for simple-cycle, heavy-duty CTs to be applied to heat rate, exhaust flow, heat consumption, and gross output. **Figure 8-30**, Combined-Cycle Compressor Inlet Temperature Curve, provides a correction factor for combined-cycle, heavy-duty CTs to be applied to heat rate, exhaust flow, heat consumption, and gross output. Some aero CTs have unique characteristics where the shape of their performance curve, related to temperature, is an inverted "V". For aero CTs, performance for a specific unit should be determined.

Compared to change in apparent compressor inlet temperature, relative humidity produces a second order effect on performance. For larger CTs, this second order effect may result in significant output changes and should be considered in detailed engineering.

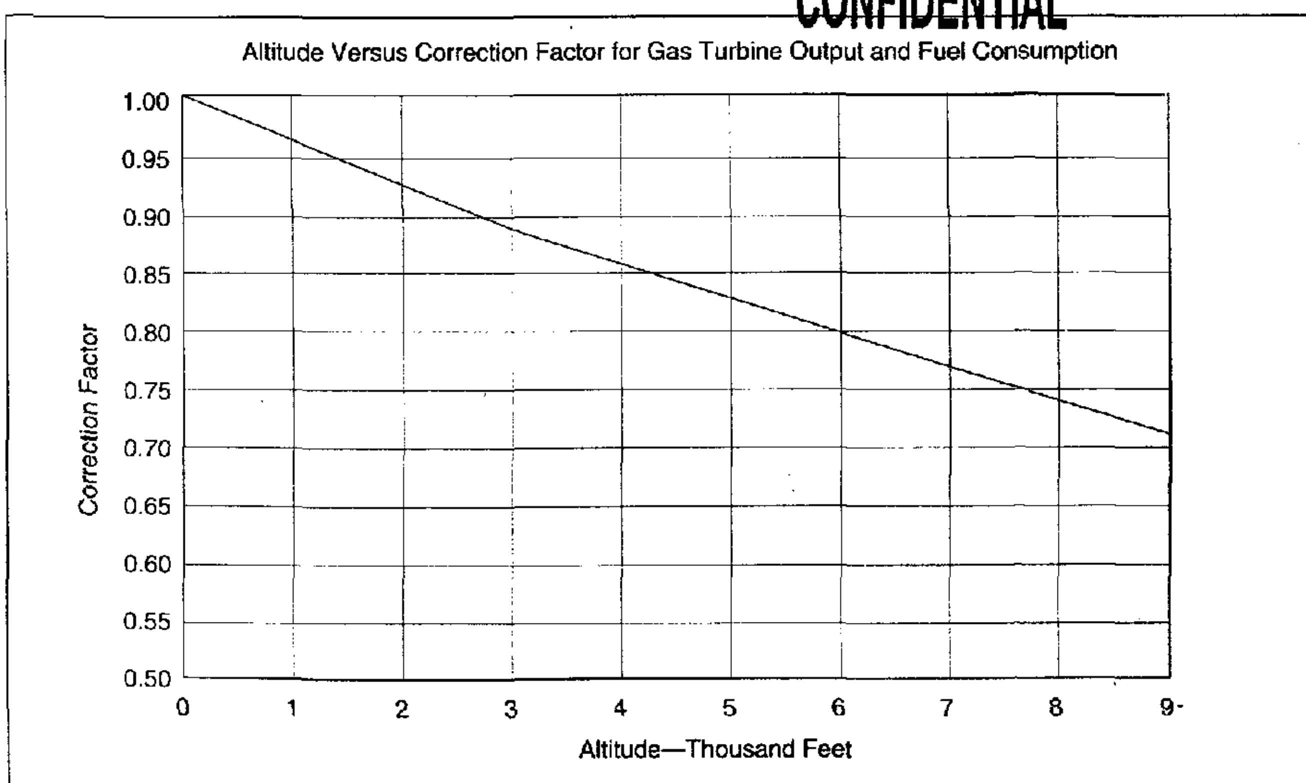

Figure 8-28. Simple-Cycle Altitude Correction Curve

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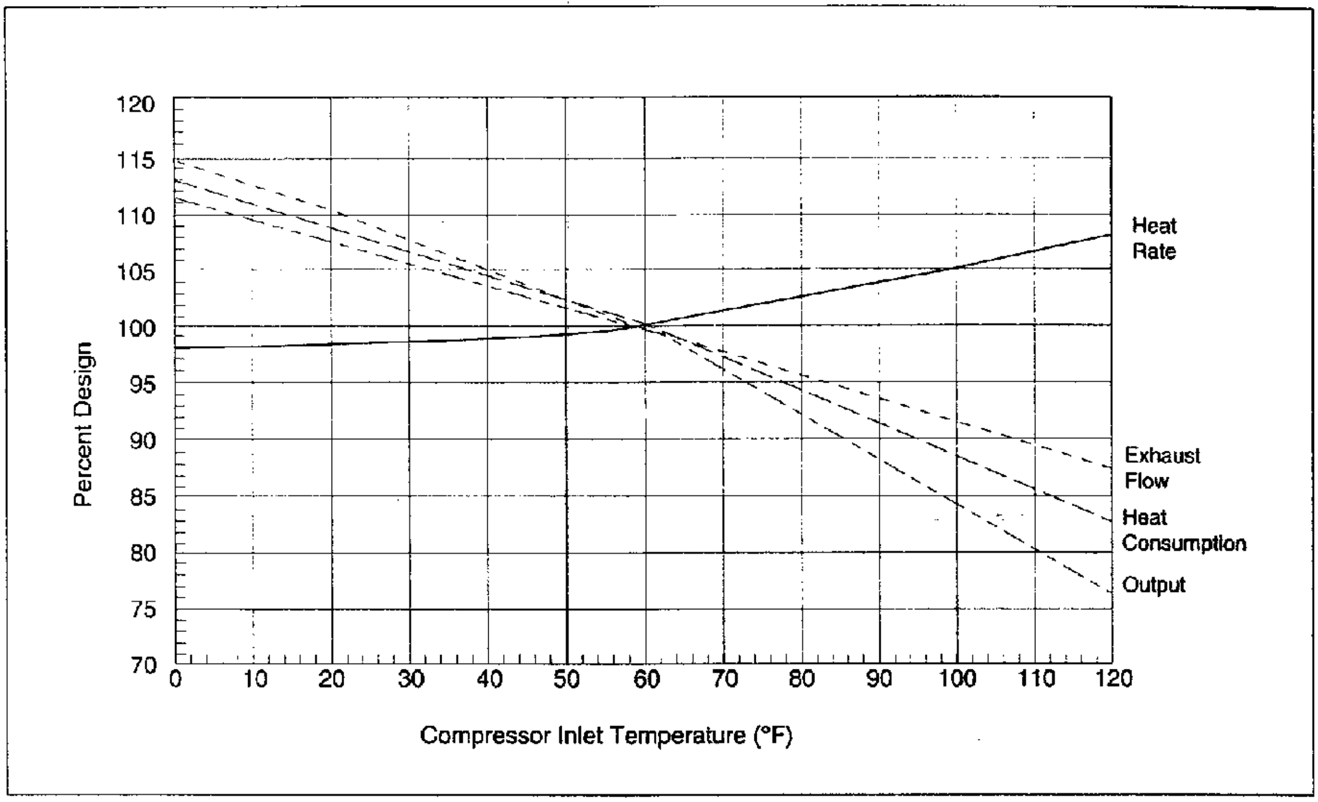

Figure 8-29. Simple-Cycle Compressor Inlet Temperature (CIT) Performance Curve

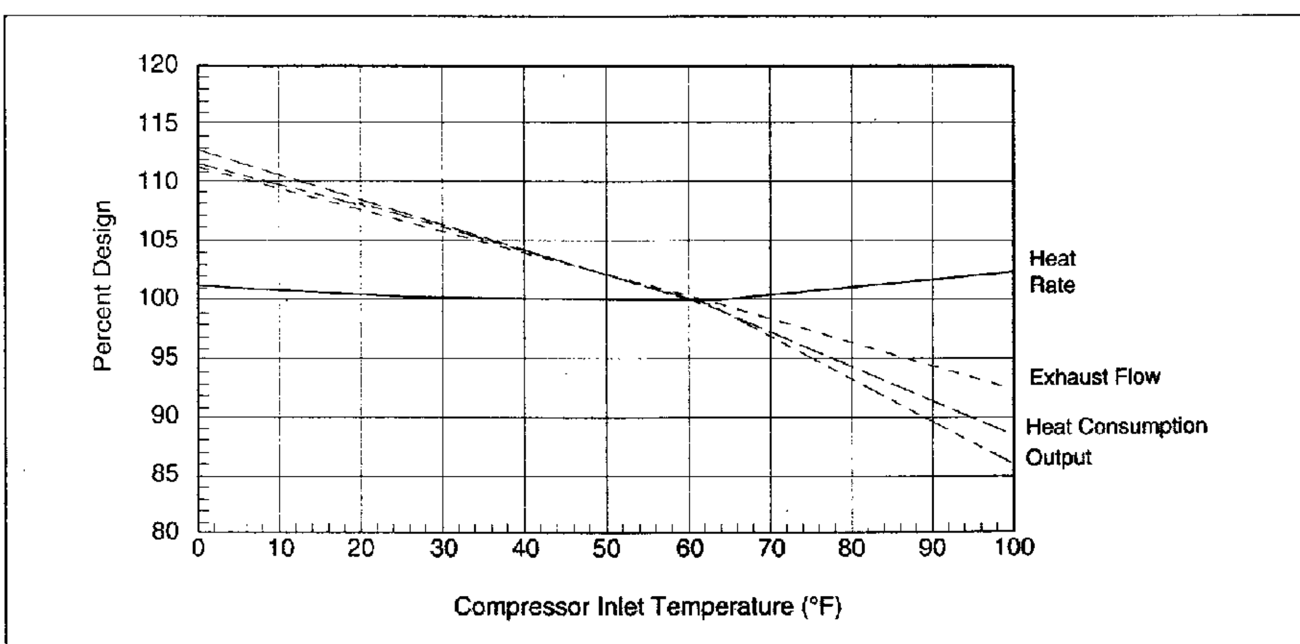

Figure 8-30. Combined-Cycle Compressor Inlet Temperature (CIT) Performance Curve

Inserting evaporative cooling, chilling, or heating coils into the inlet section may enhance CT performance by changing the apparent compressor inlet temperature from the site ambient temperature for a specific purpose. The use of a 85% effective evaporative cooler can usually improve heat rate by approximately 1%. If weather conditions (temperature, humidity) allow, greater than 1% can be achieved. An evaporative cooling system can usually be included in the compressor inlet for a capital cost between $2 and $3/kW. Inlet cooling also provides capacity gain in warm areas and can exceed 15% over ISO conditions.

Certain ambient conditions may result in ice buildup in the area of the compressor inlet and air inlet filters resulting in the possibility of a unit trip, compressor stall, or damage if the ice enters the compressor. Attention should be given to this area in detailed design. Deicing protection for the compressor inlet can usually be included in the plant design for approximately $1/kW.

Historically CTs could be operated within the criteria established by their manufacturers and owners. The current environmental climate now limits CT operation to within the window established by the air emissions permit. Manufacturers today typically guarantee the CT emissions rates at the full-load operating point in ppmvd and/or lb/h.

Operators must understand that when CT output is reduced, at some part-load condition the emission rates will rise above the permit levels (ppmvd or lb/h) and thereby preclude operation below that part-load level, unless the plant emissions permit is revised. Manufacturers should be requested to furnish data indicating where a specific CT's emissions at some part-load level will begin to exceed the rates guaranteed at full load, and as established by the plant's air emissions permit.

Part-load operation may be achieved most efficiently by closing the IGVs at the compressor inlet. This method permits maintenance of the full-load operating efficiency (heat rate) at part-load operation down to the limit of the IGVs. For most units this will result in typically 70–80% of full load. At this point the CT heat rate climbs as shown on the following generic part-load curves.

Figure 8-31, Simple-Cycle Part-Load Performance Curve, is a generic representation showing two conditions. First, part load is achieved by reducing fuel input without closing the IGVs. Second, IGVs are closed followed by reducing fuel input. Heat rate deteriorates as part-load output becomes lower.

Beyond conceptual planning and estimating, the curve pertaining to specific project equipment should be used. **Figure 8-32**, Combined-Cycle Part-Load Performance Curve, is also a generic representation showing two conditions. One curve shows part load being achieved by reducing fuel input without closing the IGVs. The second curve shows part load being achieved when IGVs are closed followed by reduced fuel input. Beyond conceptual planning and estimat-

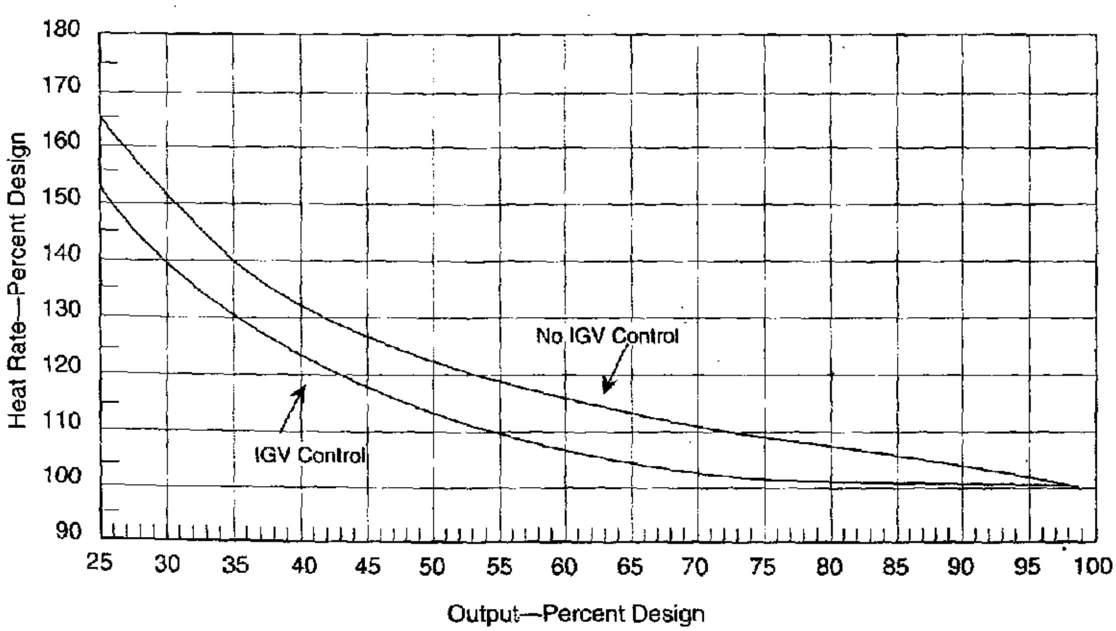

Figure 8-31. Typical Simple-Cycle Part-Load Performance Curve

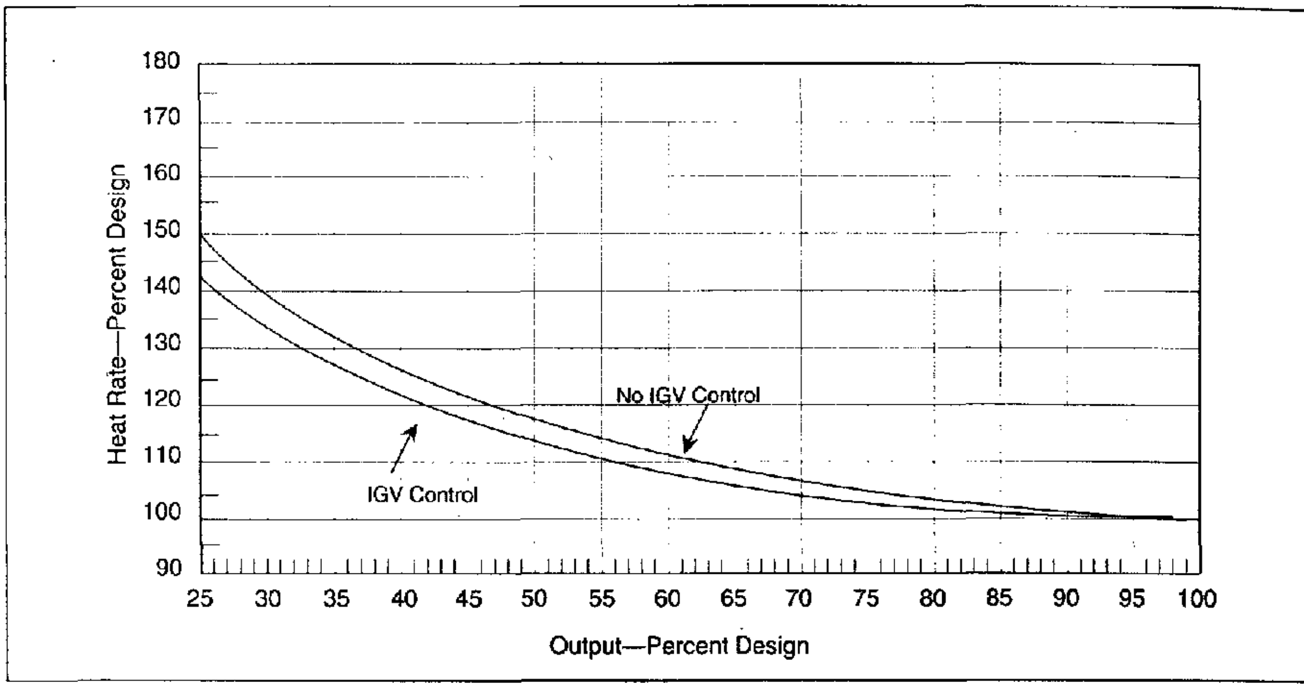

Figure 8-32. Typical Combined-Cycle Part-Load Performance Curve

ing, the curve pertaining to specific project equipment should be used.

Today both utilities and NUGs operate their generation facilities in a very cost conscious environment to maximize plant availability and to produce revenue. Historically utilities based their description of baseload, intermediate load, and peak load operation on lower annual capacity factors than are considered achievable today.

For baseload operation, NUG operation of CTCCs and CTs with HRSGs over the past several years has demonstrated that properly operated and maintained facilities will produce plants with annual operating availability factors exceeding 90%, and in many cases mid-90% plant availability factors have resulted. Using natural gas as fuel, such plants produce minimum emissions, achieve excellent heat rates, and offer the utility flexibility regarding dispatch and loading. If such a CTCC is designed with multiple CTs driving a single steam turbine, the utility has the option of operating as many CTs as is required to meet load.

For intermediate load operation, recently completed multiple CTCC plants such as Doswell have been designed specifically for dispatchable intermediate load operation. Excellent heat rates and the continuing low cost of natural gas make the CTCC alternate a serious contender for new intermediate load capacity. Such CTCC plants are usually licensed to produce single-digit NO_x emissions and in some cases, with a CO catalyst to produce single-digit CO emissions. These plants could become baseload generation in future years.

Peak duty CTs have proven to be reliable generation resources. Such units are usually licensed without SCR or CO catalyst with NO_x emissions at 25 ppmvd. The limit on total annual operation will be determined by the operation permit and will vary by geographical area to control the total tons per year of criteria pollutants. Such units can be arranged so that the CTs may be converted to CTCCs at some later date and re-permitted for such operation.

Combustion Turbine Generating Unit Design Considerations. As regards water treatment, data presented here assume demineralizer treatment for makeup water. Plant raw water supply is assumed to be from a potable, treated city water source with assumed alkalinity of 80 µS and hardness 32 ppm as $CaCO_3$. The required water treatment will be determined by raw water characteristics and the HRSG pressure level. A 1500 psig HRSG requires ultra-pure water to protect against scaling and to minimize blowdown as compared to a 700 psig HRSG, which would tolerate lesser water treatment. The mixed-bed ion exchange system included in the data contains all of the chemical storage tanks. This should be adequate to remove silica and all other harmful constituents from the makeup water. Depending on the constituents of the raw city water, however, other auxiliary equipment may be needed for proper treatment of the demineralized water (i.e., for chlorine removal, sodium sulfite equipment addition would be required). Two 100% demineralizer trains are included to permit one train to be in service while the second train is on standby or on regeneration.

If ground water (wells) is the raw water source, a pretreatment system would typically be needed. The raw water may be high in dissolved solids or other constituents that need to be removed before entering the demineralizer system. If water quality exceeds 50 total dissolved solids (TDS), an alternative to the stand-alone mixed-bed system would be required. In this case cation, anion, and mixed-bed would be recommended. If the water quality exceeds 200 TDS, additional treatment such as reverse osmosis (RO) or electrodialysis reversal (EDR) must be considered. Each of these would be followed by a mixed-bed polisher. Typical capital cost for this added water treatment is \$5-\$15/kW. For a 50 gal/min mixed-bed demineralizer, typical operating costs could be H_2SO_4 usage, \$0.20-\$0.25/thousand gallons; NaOH usage, \$0.75-\$0.85/thousand gallons; neutralization of regenerant waste, \$0.35-\$0.40/thousand gallons.

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Consumptive water use for a CTCC plant with wet cooling tower occurs primarily to supply the wet cooling tower evaporative loss and secondarily to supply HRSG and cooling tower blowdown, water treatment regeneration waste, and leakage. For conceptual estimating, wet cooling tower evaporative loss is assumed to approximate STG throttle steam flow. Elimination of this consumptive water requirement through the use of hybrid wet/dry condensers and air-cooled condensers will reduce consumptive plant water requirements from typically thousands of gal/min down to tens of gal/min.

A number of consequences must be considered, however. Typically the land area required for hybrid wet/dry condensers or air-cooled condensers, as compared to wet cooling towers, can be five or ten to one or greater. Depending on site ambient and humidity conditions, cost additions for the dry cooling towers are significant.

CTCC plants with wet cooling towers are normally designed for steam turbine operation at back pressures of 1.5 in. to 3.5 in. HgA, depending on site ambient and water temperature. CTCC plants with air-cooled condensers will require special steam turbine design for high back pressure operation, possibly 6.0 in. HgA or higher. Such a steam turbine design reduces plant output and efficiency as compared to a conventional steam turbine design. Typically a dry cooling tower design can reduce plant gross output by as much as 1%. Cost increase for dry cooling tower design can range from \$10 to \$50/kW and higher, depending on available plot space and noise abatement requirements.

The plant scope includes a building only for control room purposes. A typical metal building cost for housing the HRSG and STG would be approximately \$110 per sq ft and would be nominally 20,000 sq ft for a 200-MW CTCC Plant (\$11/kW). Such a building would include HVAC, thermal insulation, lighting, and concrete pad within the enclosed area.

No buildings are included in the data presented for weather protection or noise reduction. If only weather protection is required, due to a wet climate or low temperatures, buildings are sometimes provided to cover certain equipment. The areas typically considered for building installations at CTCC plants due to wet conditions are the STG and auxiliary areas (to protect operations and maintenance activities). Additionally, where freezing site temperatures occur, consideration is given to buildings for protection of HRSGs and other auxiliaries containing water. In severe cold climates consideration is also given to including buildings over the CTGs. Different types of construction may be used, with metal buildings used in many cases. The level of insulation and heating, cooling, and ventilation provided within such buildings is dependent on climate and the heat load produced by operating equipment in each building.

Noise reduction requirements at a site are dictated by zoning requirements and the plant operating permit. Where noise reduction is required, the first step usually involves plot layout provisions and barriers to shield sensitive areas. Beyond this, noise-producing equipment is enclosed in sealed buildings. Such buildings could be metal with insulation and barriers, or where significant noise reduction is required, success has been achieved with sealed concrete buildings. Noise reduction measures could cost as much as \$75/kW.

The data assume that a sewer is available to discharge liquid blowdowns, water treatment regeneration waste, compressor water wash, and sewage. Strict environmental regulations on discharge permits by select permitting agencies have resulted in a zero ("0") liquid discharge requirement for certain new plants. This usually occurs when the sewers or public waste treatment plants are not adequate or where no sewer exists. In these cases liquids would be discharged into runoff ditches or storm drains. In the data provided here, it is assumed that rain runoff from site parking lots and building roofs is not included; however, for certain new plants such as biomass facilities, "0" liquid discharge could also pertain to rain runoffs. When required to meet "0" liquid runoff, a tankage or collection pond is sized to contain a certain volume of liquid waste. If a collection pond is chosen, such a pond is typically required to be designed with double barrier liners with a leachate collection system between barriers. For HRSG and cooling tower blowdown, and demineralizer regeneration waste, a brine concentrator and crystallizer could be used with either a pressure filter or a centrifuge. A brine concentrator, crystallizer, and centrifuge (for waste processing) combination could recover 99% of the feed. Capital cost of this pond-cleanup combination could range from $7.5 to $15/kW. Other waste stream concentrations could require the addition of a clarifier, which would result in removal of clarifier sludge with a plate and frame filter press, using a sludge thickener. Operation of the added equipment, such as the leachate collection system, waste press, and handling and storage of the wet waste will add operating staff requirements. Added staff, hauling wet solid waste, and contracting for space at a qualified area landfill will add operation cost.

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With regard to NO_x emissions reduction equipment, data provided here assume the CTCC plant is equipped with an SCR that will provide a 9 ppmvd NO_x emission rate when starting with a gas turbine emissions rate of 25 ppmvd. The SCR is positioned in a section of the HRSG such that it operates within the temperature range that will produce efficient catalyst operation. To ensure operation within the temperature bandwidth as specified by the catalyst manufacturer, plant operation plans must be completely reviewed including duct firing and part-load operation.

The SCR system includes a control system, site ammonia delivery capability in the form of a truck off-loading station, ammonia storage, ammonia dilution system, and diluted ammonia injection system into the exhaust ducting. Diluted ammonia is injected into the hot gases upstream of the catalyst. When injected, the ammonia mixes with the hot gases such that when passing over the catalyst surface NO_x reduction occurs. The SCR control system and plant continuous emissions monitoring system ensure that the permitted NO_x emissions rate and the unreacted ammonia slip stream remains below the permitted level.

SCR systems have been successfully installed and operated such that 42 ppmvd NO_x emission rates have been reduced to as low as 5 ppmvd. Typical capital costs associated with an SCR system include mechanical equipment and initial catalyst supply of $30–$40/kW.

Operation and maintenance (O&M) of the SCR system includes replacement of the catalyst. Current plant operation indicates for baseload operation, replacing one-quarter of the catalyst beginning in the fourth or fifth year of operation typically maintains catalyst effectiveness and permitted NO_x emission rate, and stays within the permitted unreacted ammonia slipstream.

O&M costs associated with an SCR typically are

- CTCC plant operating penalty for the back pressure associated with adding an SCR and for operation of its auxiliaries is typically 0.4% of gross output.
- Catalyst replacement is on an as-needed basis and typically is expected to cost $8–$10/kW-yr.
- Ammonia consumption is expected to cost 0.06–0.08 mills/kWh.
- Air dilution fan operation typically is expected to cost 0.002 mills/kWh.
- Labor for normal maintenance and calibration typically is expected to be 2 h/shift.
- Additional labor must be budgeted for plant outages where catalyst replacement is planned.
- Spent catalyst could be considered as hazardous material. Arrangements with the catalyst manufacturer or another party should be made so that the spent catalyst does not have to be stored on site.

With regard to CO emissions reduction equipment, data provided here do not include a CO catalyst for CO emission rate reduction. In some geographical areas the air basin is not in compliance with air quality standards pertaining to CO. In such areas new projects may be called upon to reduce its CO emission rate to single-digit levels. A catalyst added for CO emissions rate reduction could be a passive system where the catalyst is added at the gas turbine exhaust, or in other cases, consideration can be given to combining this function with the NO_x catalyst. The separate catalyst added at the gas turbine exhaust can successfully operate in the nominal 1000°F temperature of the exhaust. No injections or other equipment are required. Capital cost for housing and initial catalyst is typically $20–$30/kW.

Since the separate CO catalyst is passive, no system maintenance is required; however, replacement of the catalyst will be required as its effectiveness deteriorates over time. For a baseload CTCC plant, replacement of the CO catalyst is typically required beginning in the fourth or fifth year of operation.

Typical operating and maintenance costs for a CO catalyst are

- CTCC plant operating penalty for the back pressure

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associated with adding a CO catalyst is typically 0.2–0.3% of gross output.

- Catalyst replacement is on an as-needed basis and typically is expected to cost $18–$22/kW.
- Labor for maintenance and calibration is typically 1/2 h/shift.

Combustion Turbine Air Emissions Licensing and Combustion Systems. The air board responsible for the air basin in which the project is planned determines the criteria under which permitting may be granted. The actions of this air board are governed by the policies of EPA and the Clean Air Act Amendments of 1991. If criteria air pollutants such as NO_x, CO, PM10, or UHC/VOC do not meet federal guidelines, certain emission offsets may have to be purchased in order to complete the project permitting process and be granted construction and operating permits.

For peak duty with natural gas fuel, current practice typically requires designing and permitting a project for operation up to a set maximum of operating hours per year, with NO_x emission rates of 25 ppmvd. For intermediate or baseload duty with natural gas fuel, current practice typically requires application of an SCR to achieve NO_x emission rates of 9 ppmvd. In certain air basins an additional CO catalyst is applied to reduce CO emission rates to 9 ppmvd. Where particulate/PM10 or UHC/VOC emissions must be reduced, off-site programs are sometimes considered. An example of an off-site VOC reduction program has been to install vapor collection systems on a certain number of gasoline service stations in that area. To reduce PM10s, consideration has been given to paving a certain number of miles of roadway. Permitting of each project is specific to that particular site.

As technology continues to advance, consideration must be given to designing space to add additional sections of SCR catalyst to further reduce NO_x emissions at operating projects. Additionally, consideration could be given to designing space for a CO catalyst.

Conventional CT combustion systems operating today inject water or steam for NO_x control. In most cases today these injected combustion systems are achieving reduced NO_x emission rates of 42 ppmvd, and in certain cases, 25 ppmvd.

CT manufacturer research programs have recently resulted in DLN combustors that will reduce NO_x emissions to rates of 25 ppmvd without any steam or water injection. More of these DLN combustion systems are promised from manufacturers for additional CT units within the next couple of years. To date, one manufacturer has produced a DLN system that has initially reduced NO_x emission rates to single-digit levels. This is the current goal of the research programs since owners will be able to achieve significant savings by reaching single-digit NO_x without the requirement for an SCR. Several manufacturers are promising results from DLN research programs between 1993 and 1995. Until the manufacturers are able to put into service their new DLN single-digit NO_x combustion systems and prove single-digit NO_x emission rates over an appropriate maintenance cycle, owners will have to continue designing their plants to include SCR systems to meet permit requirements. Once manufacturers prove single-digit DLN and are willing to guarantee their single-digit DLN combustion systems, owners will have the option of eliminating the SCR from their plant design.

Simple-Cycle Combustion Turbine

Cost and Performance Data

- **Exhibit 19 Heavy Duty**
  - Technology 15.1 Northeast—Natural Gas—50 MW
  - Technology 15.2 Northeast—Natural Gas—80 MW
- **Exhibit 20 Heavy Duty**
  - Technology 15.3 Northeast—Natural Gas—100 MW
  - Technology 15.4 Northeast—Natural Gas—150 MW
- **Exhibit 21 Aeroderivative**
  - Technology 15.5 Northeast—Natural Gas—25 MW
  - Technology 15.6 Northeast—Natural Gas—35 MW
  - Technology 15.7 Northeast—Natural Gas—45 MW

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References

EPRI Technical Reference Report–Agreement RP 3436-05.

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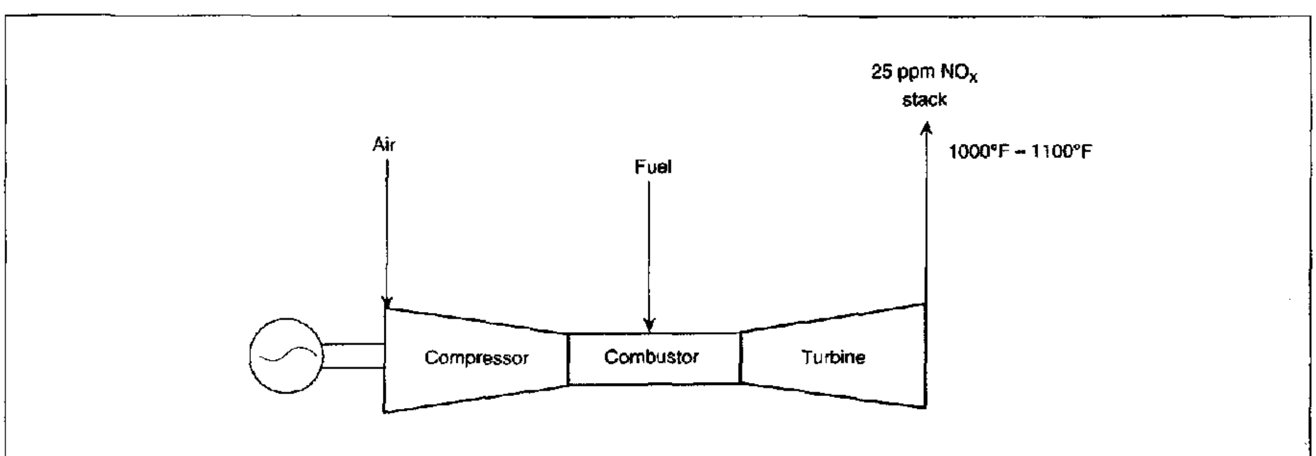

Figure 8-33. Simple-Cycle Combustion Turbine Generating Unit

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Exhibit 19
Combustion Turbine - Heavy Duty

Technology Number (a)	15.1	15.2
Region	Northeast	Northeast
Fuel Type	Natural Gas	Natural Gas
Plant Size (no. of units x unit size, MW)	1 x 50	1 x 80
Available for Commercial Orders, Year	1993	1993
First Commercial Service, Year	1993	1993
Hypothetical In-Service Year	JAN 1993	JAN 1993
Plant Capital Cost (b), $/kW		
Month/Year Dollars	DEC 1992	DEC 1992
Combustion Turbine & Aux.	320	270
General Facilities and Engineering Fee	239	158
Project and Process Contingency	61	43
Total Plant Cost	620	471
Total Cash Expended (mixed year $)	620	471
AFUDC (interest during construction)	0	0
Total Plant Investment (Includes AFUDC)	620	471
Owner Costs	17	13
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	637	484
Total Capital Replacement (for Unit Life)	-	-
Operation and Maintenance Costs,		
Costs for Hypothetical In-Service Year		
Fixed, $/kW-yr	15.5	11.6
Incremental, mills/kWh:		
Variable (includes consumables)	0.1	0.1
Consumables (includes byproducts)	0.1	0.1
Byproducts (- indicates credit)	0.0	0.0
Net Heat Rate, Btu/kWh		
Full Load	11900	11900
75% Load	12020	12020
50% Load	13450	13450
25% Load	18330	18330
Average Annual	13090	13090
Unit Availability		
Equivalent Planned Outage Rate, %	6.9	6.9
Equivalent Unplanned Outage Rate, %	10.4	10.4
Equivalent Availability, %	83.5	83.5
Capability Ratio	1.04	1.04
Duty Cycle	PEAK	PEAK
Minimum Load, %	1	1
Preconst, License & Design Time, Years	1	1
Idealized Plant Construction Time, Years	1	1
Unit Life, Years	30	30
Technology Development Rating	Mature	Mature
Design & Cost Estimate Rating	Preliminary	Preliminary

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(a) See **Subsection 8.4** for definition of terms.
(b) Estimated cost ranges in **Table 8-10**.
O&M cost calculations have been revised. See **Subsection 5.6.2**.

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Exhibit 20
Combustion Turbine - Heavy Duty

Technology Number (a)	15.3	15.4
Region	Northeast	Northeast
Fuel Type	Natural Gas	Natural Gas
Plant Size (no. of units x unit size, MW)	1 x 100	1 x 150
Available for Commercial Orders, Year	1993	1993
First Commercial Service, Year	1993	1993
Hypothetical In-Service Year	JAN 1993	JAN 1993
Plant Capital Cost (b), $/kW		
Month/Year Dollars	DEC 1992	DEC 1992
Combustion Turbine & Aux.	240	270
General Facilities and Engineering Fee	139	107
Project and Process Contingency	40	43
Total Plant Cost	419	420
Total Cash Expended (mixed year $)	419	420
AFUDC (interest during construction)	0	0
Total Plant Investment (Includes AFUDC)	419	420
Owner Costs	12	12
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	431	432
Total Capital Replacement (for Unit Life)	-	-
Operation and Maintenance Costs,		
Costs for Hypothetical In-Service Year		
Fixed, $/kW-yr	10.5	10.2
Incremental, mills/kWh:		
Variable (includes consumables)	0.1	0.1
Consumables (includes byproducts)	0.1	0.1
Byproducts (- indicates credit)	0.0	0.0
Net Heat Rate, Btu/kWh		
Full Load	11700	11100
75% Load	11820	11210
50% Load	13220	12540
25% Load	18020	17090
Average Annual	12870	12210
Unit Availability		
Equivalent Planned Outage Rate, %	6.9	6.9
Equivalent Unplanned Outage Rate, %	10.4	10.4
Equivalent Availability, %	83.5	83.5
Capability Ratio	1.04	1.04
Duty Cycle	PEAK	PEAK
Minimum Load, %	1	1
Preconst, License & Design Time, Years	1	1
Idealized Plant Construction Time, Years	1	1
Unit Life, Years	30	30
Technology Development Rating	Mature	Mature
Design & Cost Estimate Rating	Preliminary	Preliminary

(a) See **Subsection 8.4** for definition of terms.
(b) Estimated cost ranges in **Table 8-10**.
O&M cost calculations have been revised. See **Subsection 5.6.2.**

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Exhibit 21
Combustion Turbine - Aeroderivative

Technology Number (a)	15.5	15.6	15.7
Region	Northeast	Northeast	Northeast
Fuel Type	Natural Gas	Natural Gas	Natural Gas
Plant Size (no. of units x unit size, MW)	1 x 25	1 x 35	1 x 45
Available for Commercial Orders, Year	1993	1993	1993
First Commercial Service, Year	1993	1993	1993
Hypothetical In-Service Year	JAN 1993	JAN 1993	JAN 1993
Plant Capital Cost (b), $/kW			
Month/Year Dollars	DEC 1992	DEC 1992	DEC 1992
Combustion Turbine & Aux.	470	400	380
General Facilities and Engineering Fee	378	321	254
Project and Process Contingency	91	78	65
Total Plant Cost	939	799	699
Total Cash Expended (mixed year $)	939	799	699
AFUDC (interest during construction)	0	0	0
Total Plant Investment (includes AFUDC)	939	799	699
Owner Costs	26	22	19
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	965	821	718
Total Capital Replacement (for Unit Life)	-	-	-
Operation and Maintenance Costs,			
Costs for Hypothetical In-Service Year			
Fixed, $/kW-yr	23.8	18.0	15.0
Incremental, mills/kWh:			
Variable (includes consumables)	0.1	0.1	0.1
Consumables (includes byproducts)	0.1	0.1	0.1
Byproducts (- indicates credit)	0.0	0.0	0.0
Net Heat Rate, Btu/kWh			
Full Load	10700	10700	10000
75% Load	11770	11770	11000
50% Load	13160	13160	12300
25% Load	17660	17660	16500
Average Annual	11770	11770	11000
Unit Availability			
Equivalent Planned Outage Rate, %	-	-	-
Equivalent Unplanned Outage Rate, %	-	-	-
Equivalent Availability, %	-	-	-
Capability Ratio	-	-	-
Duty Cycle	PEAK	PEAK	PEAK
Minimum Load, %	1	1	1
Preconst, License & Design Time, Years	1	1	1
Idealized Plant Construction Time, Years	1	1	1
Unit Life, Years	30	30	30
Technology Development Rating	Mature	Mature	Mature
Design & Cost Estimate Ratinag	Preliminary	Preliminary	Preliminary

(a) See **Subsection 8.4** for definition of terms.
(b) Estimated cost ranges in **Table 8-10**.
O&M cost calculations have been revised.See **Subsection 5.6.2**.

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Simple Cycle Combustion Turbine—Steam Injected

Cost and Performance Data

- **Exhibit 22 Combustion Turbine—STIG**
  - Technology 15.8 Northeast—Natural Gas—50 MW

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EPRI Technical Reference Report–Agreement RP 3436-05.

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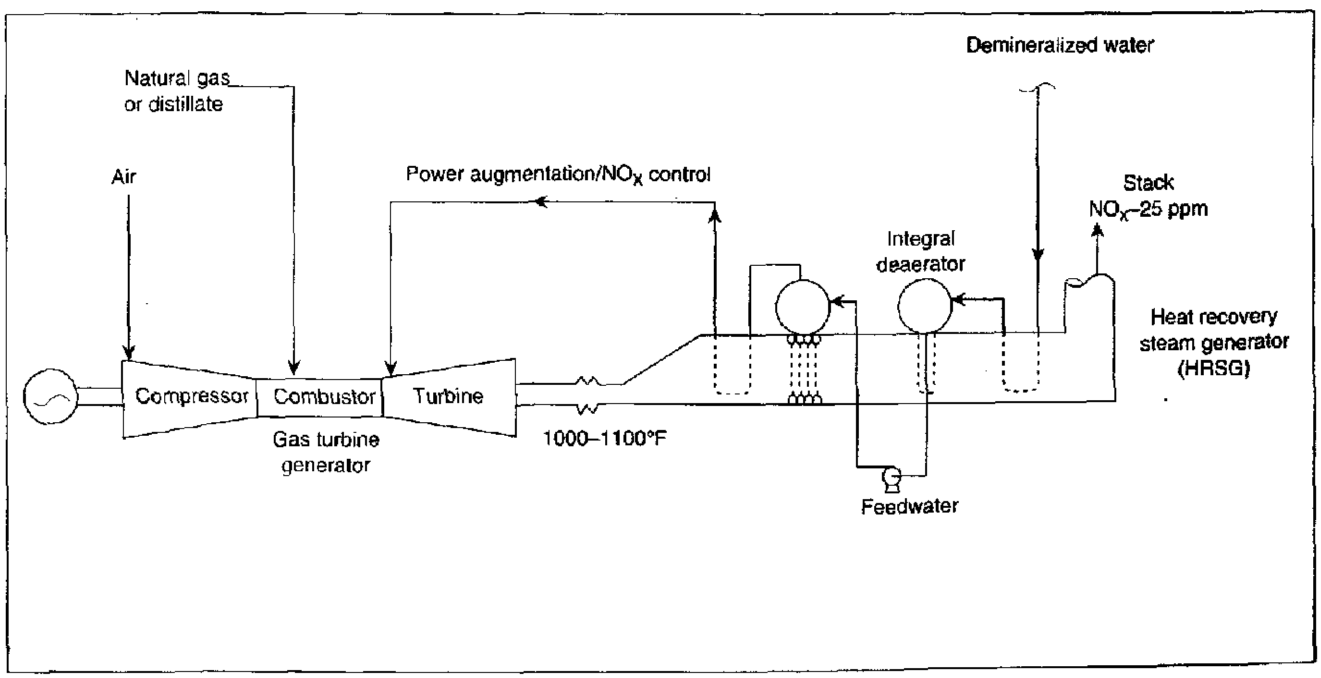

Figure 8-34. STIG Cycle Combustion Turbine Generating Unit

Exhibit 22
Combustion Turbine - STIG

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Technology Number (a)	15.8
Region	Northeast
Fuel Type	Natural Gas
Plant Size (no. of units x unit size, MW)	1 x 50
Available for Commercial Orders, Year	1993
First Commercial Service, Year	1993
Hypothetical In-Service Year	JAN 1993
Plant Capital Cost (b), $/kW	
Month/Year Dollars	DEC 1992
Combustion Turbine & Aux.	310
Steam Generator	71
General Facilities and Engineering Fee	336
Project and Process Contingency	82
Total Plant Cost	799
Total Cash Expended (mixed year $)	799
AFUDC (interest during construction)	0
Total Plant Investment (Includes AFUDC)	799
Owner Costs	23
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	822
Total Capital Replacement (for Unit Life)	-
Operation and Maintenance Costs,	
Costs for Hypothetical In-Service Year	
Fixed, $/kW-yr	32.5
Incremental, mills/kWh:	
Variable (includes consumables)	0.6
Consumables (includes byproducts)	0.6
Byproducts (- indicates credit)	0.0
Net Heat Rate, Btu/kWh	
Full Load	9000
75% Load	9900
50% Load	11070
25% Load	14850
Average Annual	9900
Unit Availability	
Equivalent Planned Outage Rate, %	6.9
Equivalent Unplanned Outage Rate, %	6.1
Equivalent Availability, %	87.5
Capability Ratio	1.04
Duty Cycle	INTERMEDIATE
Minimum Load, %	1
Preconst, License & Design Time, Years	1
Idealized Plant Construction Time, Years	1
Unit Life, Years	30
Technology Development Rating	Mature
Design & Cost Estimate Rating	Preliminary

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(a) See **Subsection 8.4** for definition of terms.
(b) Estimated cost ranges in **Table 8-10**.
O&M cost calculations have been revised. See **Subsection 5.6.2**.

Combustion Turbine–Combined Cycle

Cost and Performance Data

- **Exhibit 23 Combustion Turbine—Combined Cycle**
  - Technology 16.1 Northeast—Natural Gas—120 MW
  - Technology 16.2 Northeast—Natural Gas—150 MW
  - Technology 16.3 Northeast—Natural Gas—225 MW

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EPRI Technical Reference Report–Agreement RP 3436-05.

1. Robert Edgell and Jim Henneforth. "Cogeneration Operating Experience Using Sixteen Industrial Grade Combustion Turbines." ASME, June 1990.
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4. "Chesterfield 7 Sets Record." *Cogeneration Magazine*, June–July 1992.
5. Larry Flashberg and Gary Haub. "Measurement of Combustion Turbine Non-Recoverable Degradation." International Gas Turbine and Aeroengine Congress and Exposition, June 1992.

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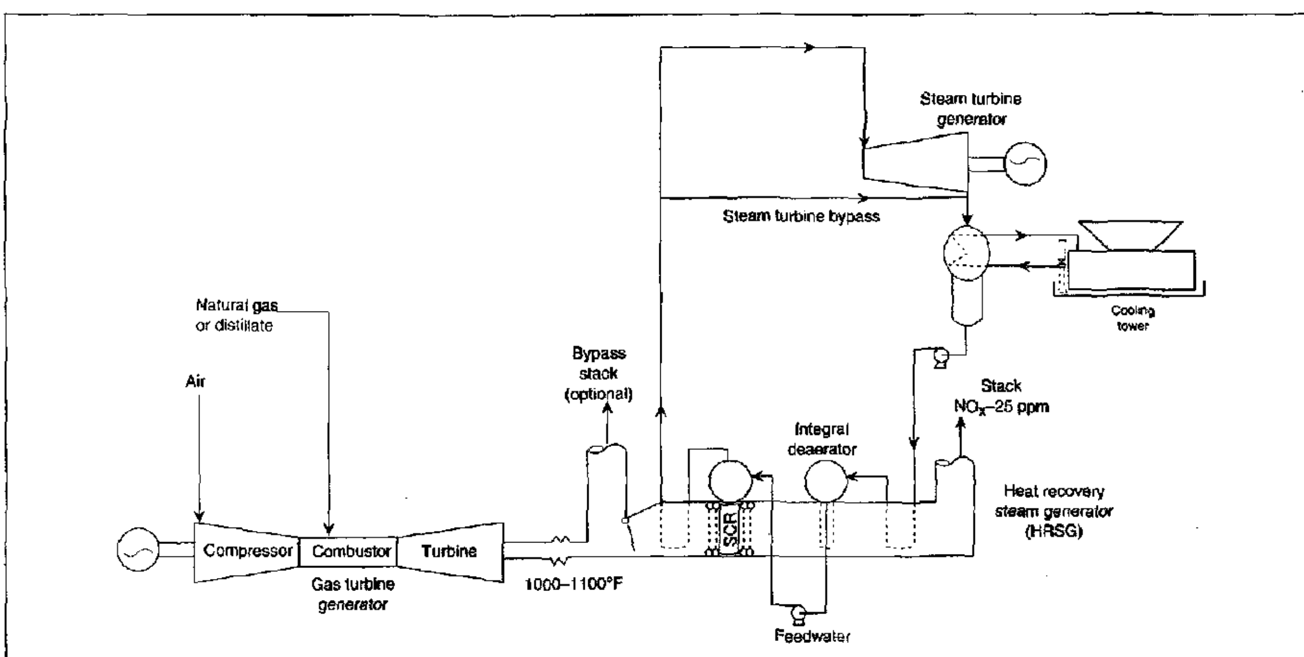

Figure 8-35. Combustion Turbine Combined-Cycle Generating Unit

Exhibit 23
Combustion Turbine/Combined Cycle

Technology Number (a)	16.1	16.2	16.3
Region	Northeast	Northeast	Northeast
Fuel Type	Natural Gas	Natural Gas	Natural Gas
Plant Size (no. of units x unit size, MW)	1 x 120	1 x 150	1 x 225
Available for Commercial Orders, Year	1993	1993	1993
First Commercial Service, Year	1993	1993	1993
Hypothetical In-Service Year	JAN 1993	JAN 1993	JAN 1993
Plant Capital Cost (b), $/kW			
Month/Year Dollars	DEC 1992	DEC 1992	DEC 1992
Combustion Turbine & Aux.	180	160	180
HRSG	68	69	65
Steam Turbine, Gen., & Aux.	64	62	58
General Facilities and Engineering Fee	292	253	199
Project and Process Contingency	76	65	58
Total Plant Cost	680	609	560
Total Cash Expended (mixed year $)	667	597	549
AFUDC (interest during construction)	35	31	29
Total Plant Investment (Includes AFUDC)	702	629	578
Owner Costs	21	19	17
Total Capital Requirement, Hypothetical In-Service Year (includes AFUDC)	723	648	595
Total Capital Replacement (for Unit Life)	-	-	-
Operation and Maintenance Costs,			
Costs for Hypothetical In-Service Year			
Fixed, $/kW-yr	34.4	32.0	26.5
Incremental, mills/kWh:			
Variable (includes consumables)	0.4	0.4	0.4
Consumables (includes byproducts)	0.4	0.4	0.4
Byproducts (- indicates credit)	0.0	0.0	0.0
Net Heat Rate, Btu/kWh			
Full Load	7900	7800	7300
75% Load	8140	8030	7520
50% Load	9010	8890	8320
25% Load	11380	11230	10510
Average Annual	8140	8030	7520
Unit Availability			
Equivalent Planned Outage Rate, %	6.9	6.9	6.9
Equivalent Unplanned Outage Rate, %	4.6	4.6	4.6
Equivalent Availability, %	88.9	88.9	88.9
Capability Ratio	1.06	1.06	1.06
Duty Cycle	BASE	BASE	BASE
Minimum Load, %	1	1	1
Preconst, License & Design Time, Years	2	2	2
Idealized Plant Construction Time, Years	2	2	2
Unit Life, Years	30	30	30
Technology Development Rating	Mature	Mature	Mature
Design & Cost Estimate Rating	Preliminary	Preliminary	Preliminary

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(a) See **Subsection 8.4** for definition of terms.
(b) Estimated cost ranges in **Table 8-10**.
O&M cost calculations have been revised. See **Subsection 5.6.2**.

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