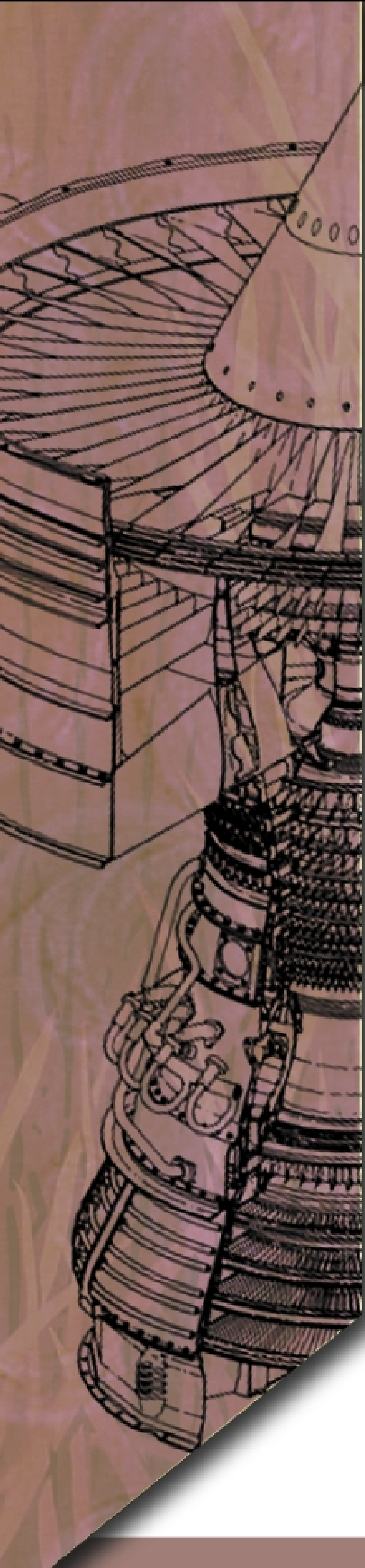


GAS TURBINES IN SIMPLE CYCLE & COMBINED CYCLE APPLICATIONS*

<u>Gas Turbines in Simple Cycle Mode</u>

Introduction

The gas turbine is the most versatile item of turbomachinery today. It can be used in several different modes in critical industries such as power generation, oil and gas, process plants, aviation, as well domestic and smaller related industries.

A gas turbine essentially brings together air that it compresses in its compressor module, and fuel, that are then ignited. Resulting gases are expanded through a turbine. That turbine's shaft continues to rotate and drive the compressor which is on the same shaft, and operation continues. A separate starter unit is used to provide the first rotor motion, until the turbine's rotation is up to design speed and can keep the entire unit running.

The compressor module, combustor module and turbine module connected by one or more shafts are collectively called the gas generator. The figures below (Figures 1 and 2) illustrate a typical gas generator in cutaway and schematic format.

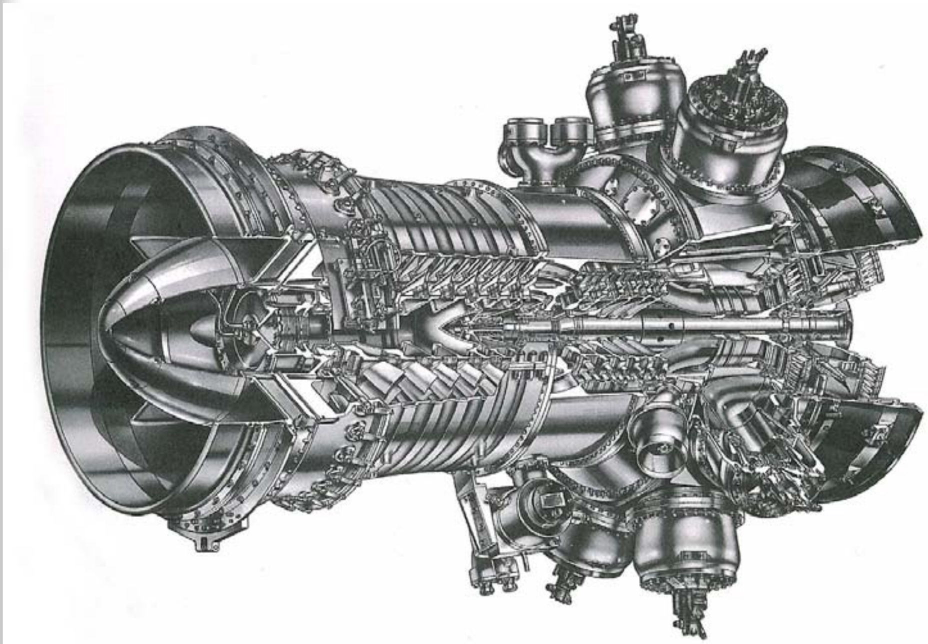


Fig. 1. Rolls Royce RB211 Dry Low Emissions Gas Generator
(Source: Process Plant Machinery, 2nd edition, Bloch & Soares, C.
pub: Butterworth Heinemann, 1998)

* Condensed extracts from selected chapters of "Gas Turbines: A Handbook of Land, Sea and Air Applications" by Claire Soares, publisher Butterworth Heinemann, BH, (for release information see www.bh.com) Other references include Claire Soares' other books for BH and McGraw Hill (see www.books.mcgraw-hill.com) and course notes from her courses on gas turbine systems. **For any use of this material that involves profit or commercial use (including work by nonprofit organizations), prior written release will be required from the writer and publisher in question.**

Please note that several topics in the gas turbine handbook, for instance Turbine Controls, Instrumentation and Diagnostics; as well as Performance Optimization and Environmental issues are not covered in this author's material on this CD. The "Gas Turbines" book in question is several hundred pages long and besides the basics, covers some of the more complex and lengthy work in recent gas turbine development. Condensing it all here was not practical. What is here however, does give the reader the basic theory and practice of gas turbines in simple cycle and combined cycle mode, in power generation service.

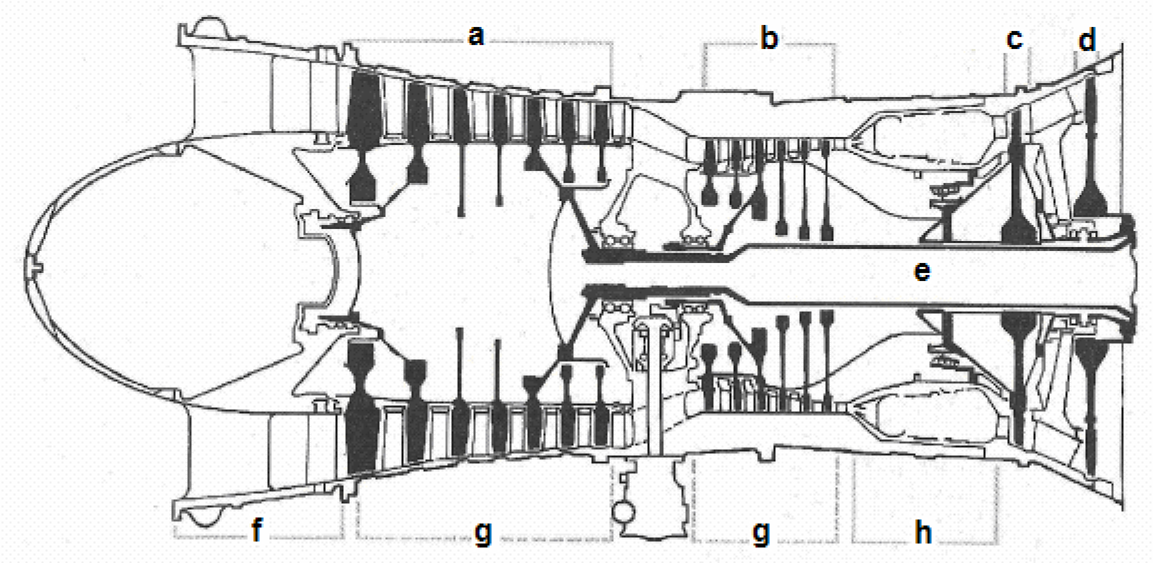


Fig. 2. Schematic of modules: f: fan section, ag: low pressure compressor, bg: high pressure compressor, c: turbine, e: shaft, h: combustor (Source: Process Plant Machinery, 2nd edition, Bloch & Soares, C. pub: Butterworth Heinemann, 1998)

Figure 3 below shows a gas turbine cutaway with its basic operating specification. Note this particular turbine model can be used for both 50 and 60Hz power generation.

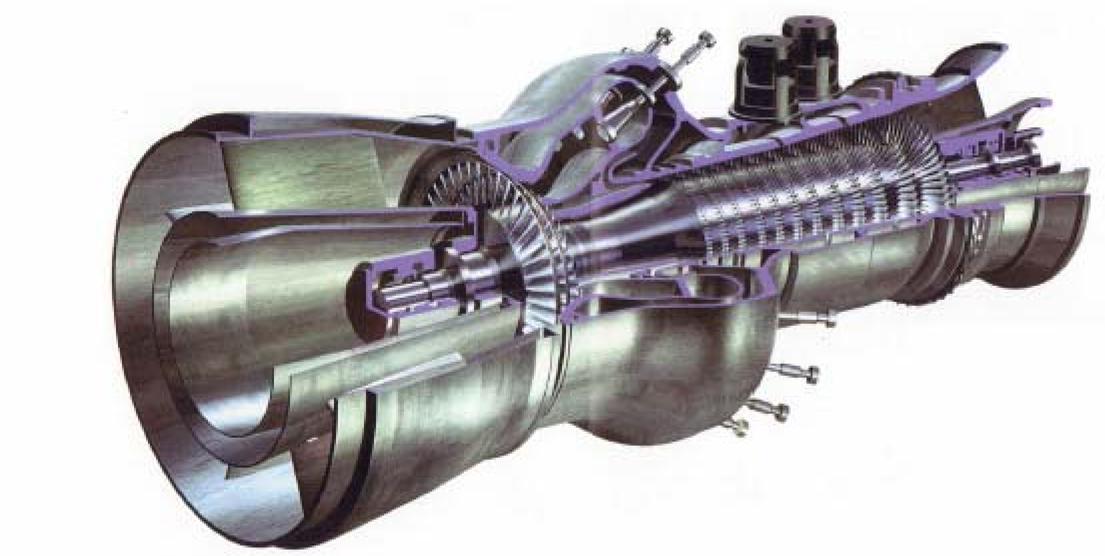


Fig. 3. Alstom's GT-8C2, 50/60Hz gas turbine with basic specification (Table 1: base load at ISO conditions) (Source: Alstom Power)

Table 1. GT8C2 (60Hz) (ISO 2314: 1989)

Fuel	Natural Gas
Frequency	60 Hz
Gross electrical output	56.2 MW
Gross electrical efficiency	33.8%
Gross Heat Rate	10,098 Btu / kWh
Turbine speed	6204 rpm
Compressor pressure ratio	17.6:1
Exhaust gas flow	197 kg/s
Exhaust gas temperature	508 °C
NO_x emissions, gas dry (corr. to 15% O_2, dry)	< 25 vppm

Figure 4 shows another cutaway of another gas turbine. This gas turbine is used in 60Hz power generation service.

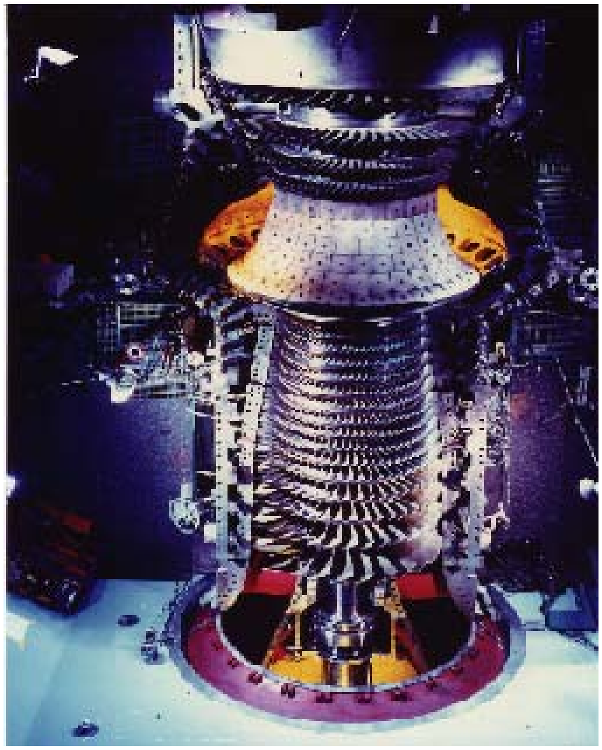


Fig. 4. Siemens V84.3A, 60Hz gas turbine. Note partial hybrid burner (24 burners) ring

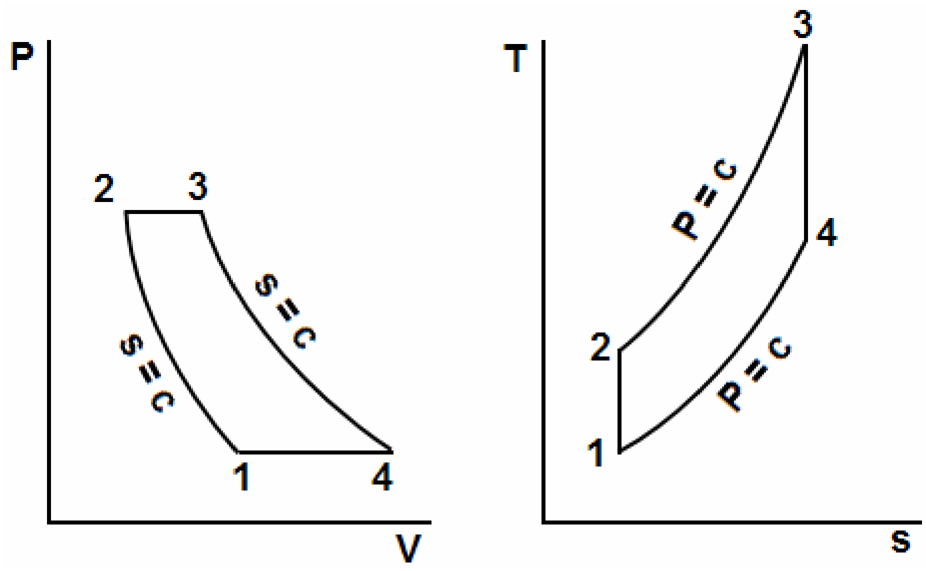


Fig. 5. The basic gas turbine cycle (Source: The Aircraft Engine Book, Rolls Royce UK)

The basic gas turbine cycle is illustrated (PV and T-s diagrams) in Figure 5. A comparison can be drawn between the gas turbine's operating principle and a car engine's. See Figures 5 and 6. A car operates with a piston engine (reciprocating motion) and typically handles much smaller volumes than a conventional gas turbine.

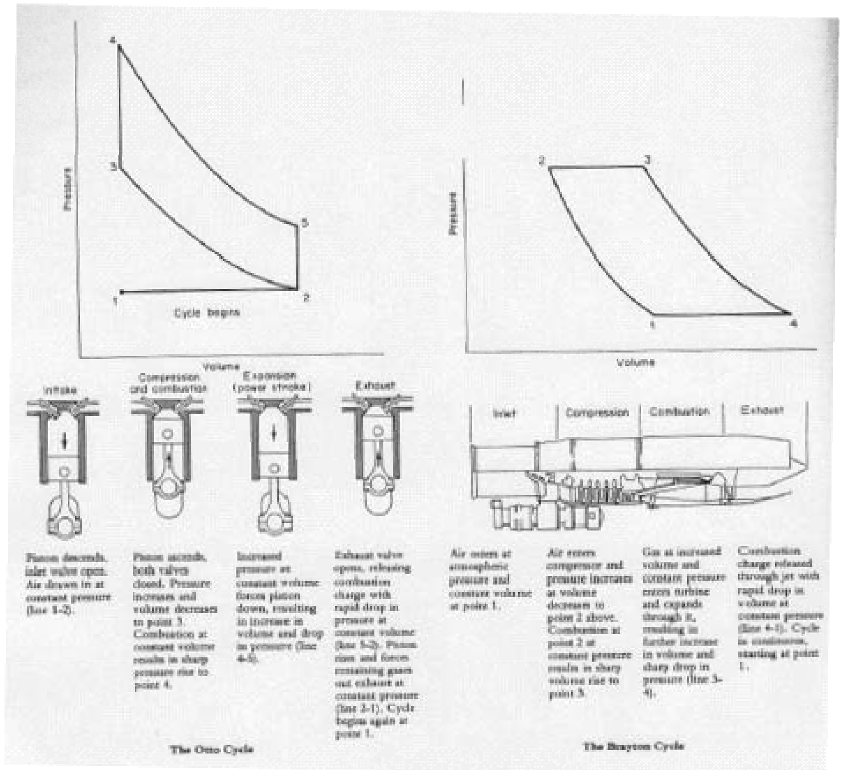


Fig. 6. Comparison of the gas turbine and the reciprocating engine cycles (Source: The Aircraft Engine Book, Rolls Royce UK)

GT Applications (Simple Cycle)

Direct drive and mechanical drive

With land-based industries, gas turbines can be used in either direct drive or mechanical drive application. With power generation, the gas turbine shaft is coupled to the generator shaft, either directly or via a gearbox "direct drive" application. A gearbox is necessary in applications where the manufacturer offers the package for both 60 and 50 cycle (Hertz, Hz) applications. The gear box will use roughly 2 percent of the power developed by the turbine in these cases.

Fig. 7. A simple cycle gas turbine plant**,**
100 MW simple cycle power plant,
Charleston, South Carolina USA, powered
by Siemens gas turbines. (Source: Siemens Westinghouse)

Power generation applications extend to offshore platform use. Minimizing weight is a major consideration for this service and the gas turbines used are generally "aeroderivatives" (derived from lighter gas turbines developed for aircraft use).

For mechanical drive applications, the turbine module arrangement is different. In these cases, the combination of compressor module, combustor module and turbine module is termed the gas generator. Beyond the turbine end of the gas generator is a freely rotating turbine. It may be one or more stages. It is not mechanically connected to the gas generator, but instead is mechanically coupled, sometimes via a gearbox, to the equipment it is driving. Compressors and pumps are among the potential "driven" turbomachinery items. See Figure 8 below.

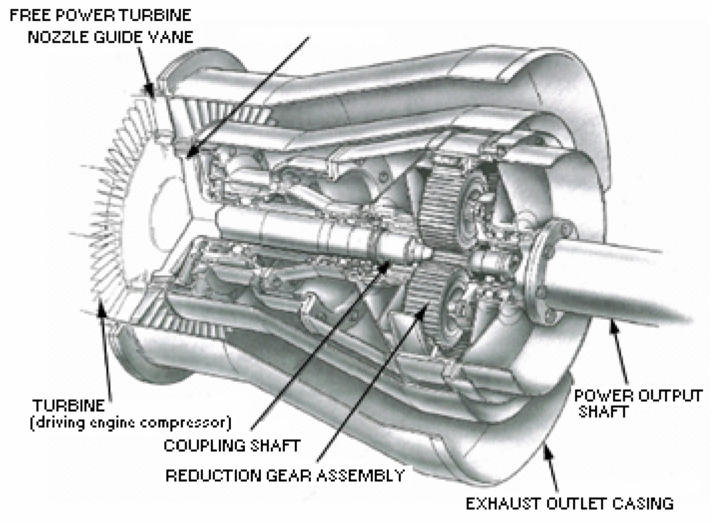


Fig. 8. A typical free power turbine. (Source: Rolls-Royce, UK)

In power generation applications, a gas turbine's power/ size is measured by the power it develops in a generator (units watts, kilowatts, Megawatts). In mechanical drive applications, the gas turbine's power is measured in horsepower (HP), which is essentially the torque developed multiplied by the turbine's rotational speed.

In aircraft engine applications, if the turbine is driving a rotor (helicopter) or propeller (turboprop aircraft) then its power is measured in horsepower. This means that the torque transmission from the gas turbine shaft is, in principle, a variation of mechanical drive application. If an aircraft gas turbine engines operates in turbothrust or ramjet mode, (i.e. the gas turbine expels its exhaust gases and the thrust of that expulsion, propels the aircraft forward), its power is measured in pounds of thrust. See Figure 9 below.

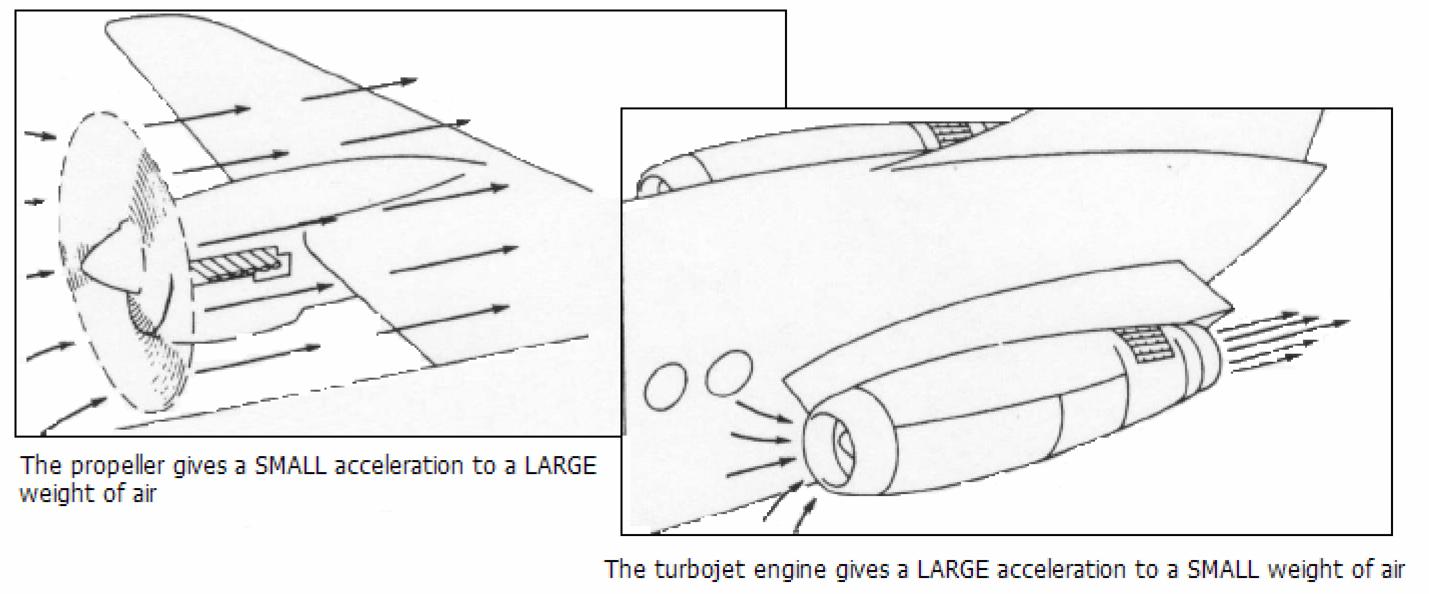
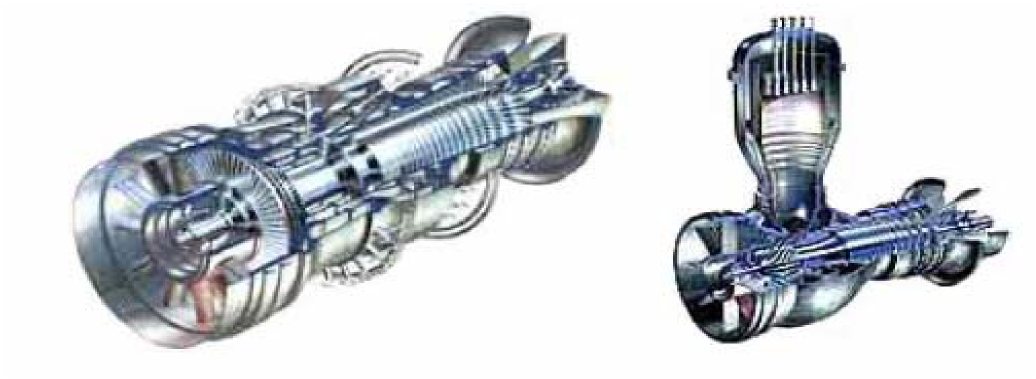


Fig. 9. Propulsive efficiency is high for a propeller and low for a jet. (Source: Rolls-Royce, UK)

Fig. 10. Gas turbines in offshore service: Offshore platforms produce their own power. Power plant selection is generally an aeroderivative (for weight considerations) gas turbine in simple cycle operation. (Source: GE Power Systems)

In marine applications, the gas turbine is generally driving the ship's or ferry's propellers, via a gear box.

Fig. 11. Gas turbines in marine service: SGT-500 Industrial Gas Turbine – 17 MW, Application: Two SGT-500 power packages for FPSO vessel in the Leadon oilfields (Note the SGT-500 was Alstom's, formerly ABB's GT-35, designation changed after Siemens acquisition). The Global Producer III from the Swan Hunter shipyards at Tyneside, UK, heads for the Leadon oil field in the UK Sector of the North Sea. This vessel is an FPSO (Floating Production, Storage and Offloading) vessel, and power on board is provided by two SGT-500 gas turbines. One WHRG (Waste Heat Recovery Generator) for each gas turbine heats process water. The SGT-500 is a light-weight, high-efficiency, heavy-duty industrial gas turbine. Its special design features are high reliability and fuel flexibility. It is also designed for single lift, which makes the unit suitable for all offshore applications. The modular, compact design of the GT35C facilitates onsite modular exchange. (Source: Siemens Westinghouse)



GT24/26 GT11N2

Fig. 12a. Pictorial Examples of gas turbines, some with main operational parameters (Source: Alstom)

Table 2. Alstom's GT 24/ GT 26 (188MW 60Hz, 281MW 50Hz). Both used in simple cycle, combined cycle and other co-generation applications.

GT24 (ISO 2314:1989)

Fuel	Natural gas
Frequency	60 Hz
Gross Electrical output	187.7 MW*
Gross Electrical efficiency	36.9 %
Gross Heat rate	9251 Btu/kWh
Turbine speed	3600 rpm
Compressor pressure ratio	32:1
Exhaust gas flow	445 kg/s
Exhaust gas temperature	612 °C
NOx emissions (corr. to 15% O2,dry)	< 25 vppm

GT26 (ISO 2314:1989)

Fuel	Natural gas
Frequency	50 Hz
Gross Electrical output	281 MW*
Gross Electrical efficiency	38.3 %
Gross Heat rate	8910 Btu/kWh
Turbine speed	3000 rpm
Compressor pressure ratio	32:1
Exhaust gas flow	632 kg/s
Exhaust gas temperature	615 °C
NOx emissions (corr. to 15% O2, dry)	< 25 vppm

In combined cycle, approximately 12 MW (GT26) or 10 MW (GT24) is indirectly produced by the steam turbine through the heat released in the gas turbine cooling air coolers into the water steam cycle.

Table 3. Alstom's GT 11N2, either 60Hz or 50 Hz (with a gear box).
Used in simple cycle, combined cycle and other cogeneration applications.

GT11N2 (50Hz)

Fuel	Natural Gas
Frequency	50 Hz
Gross Electrical output	113.6 MW
Gross Electrical efficiency	33.1%
Gross Heat rate	10,305 Btu/kWh
Turbine speed	3600 rpm
Compressor pressure ratio	15.5:1
Exhaust gas flow	399 kg/s
Exhaust gas temperature	531 °C
NO_x emissions (corr. to 15% O2,dry)	< 25 vppm

GT11N2 (60Hz)

Fuel	Natural gas
Frequency	60 Hz
Gross Electrical output	115.4 MW
Gross Electrical efficiency	33.6%
Gross Heat rate	10,150 Btu/kWh
Turbine speed	3600 rpm
Compressor pressure ratio	15.5 : 1
Exhaust gas flow	399 kg/s
Exhaust gas temperature	531 °C
NO_x emissions (corr. to 15% O2,dry)	< 25 vppm

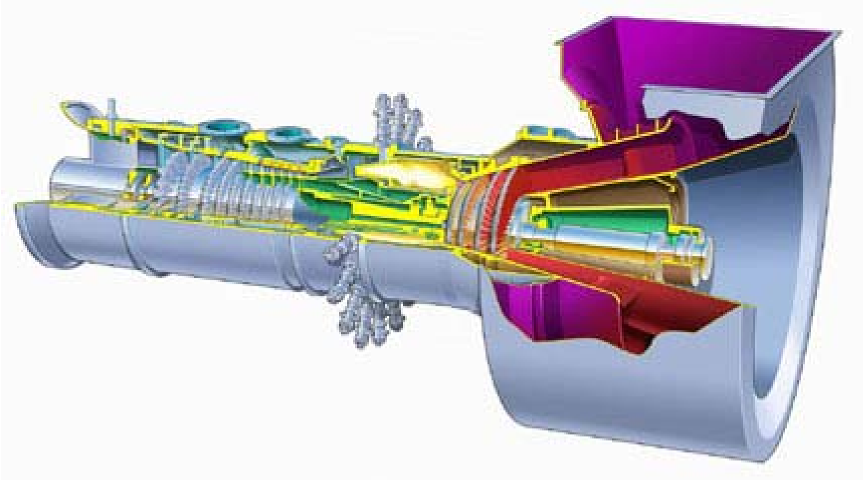


Fig. 12b. SGT-600 Industrial Gas Turbine - 25 MW (former designation, Alstom's GT10) (Source: Siemens Westinghouse)

Technical Specifications	
Dual Fuel	natural gas and liquid
Frequency	50/60 Hz
Electrical output	24.8 MW
Electrical efficiency	34.2%
Heat rate	10,535 kJ/kWh
Turbine speed	7,700 rpm
Compressor pressure ratio	14.0:1
Exhaust gas flow	80.4 kg/s
Exhaust gas temperature	543 deg C
NO_x emissions (corr. to 15% O2, dry)	<25 vppm

Figures 13 and 14 depict a cutaway and an external view respectively, of two aeroderivative engine models.

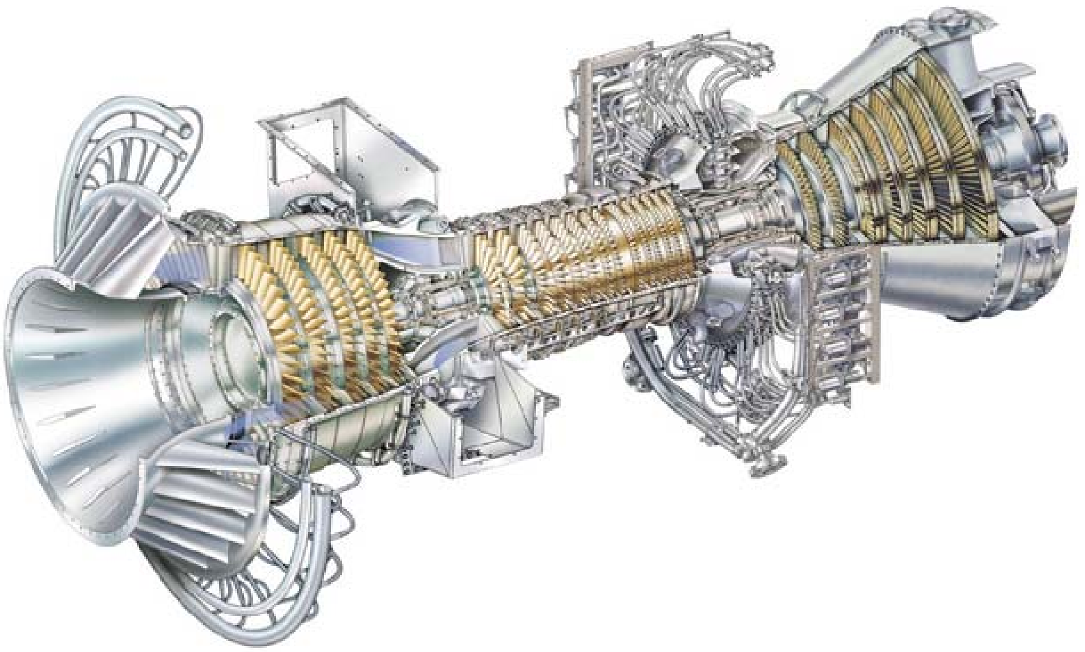


Fig. 13. The GE LM6000 (aeroderivative of the CF6-80C2). (Source: GE Power Systems)

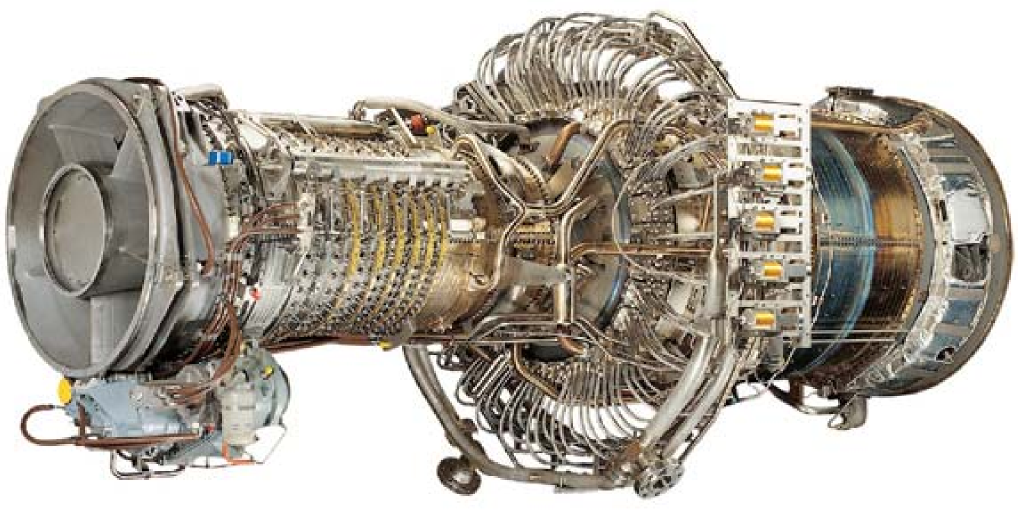


Fig. 14. The GE LM2500 (aeroderivative of the CF6-80C2). (Source: GE Power Systems)

Figure 15 shows an industrial gas turbine during assembly at the OEM's facility.

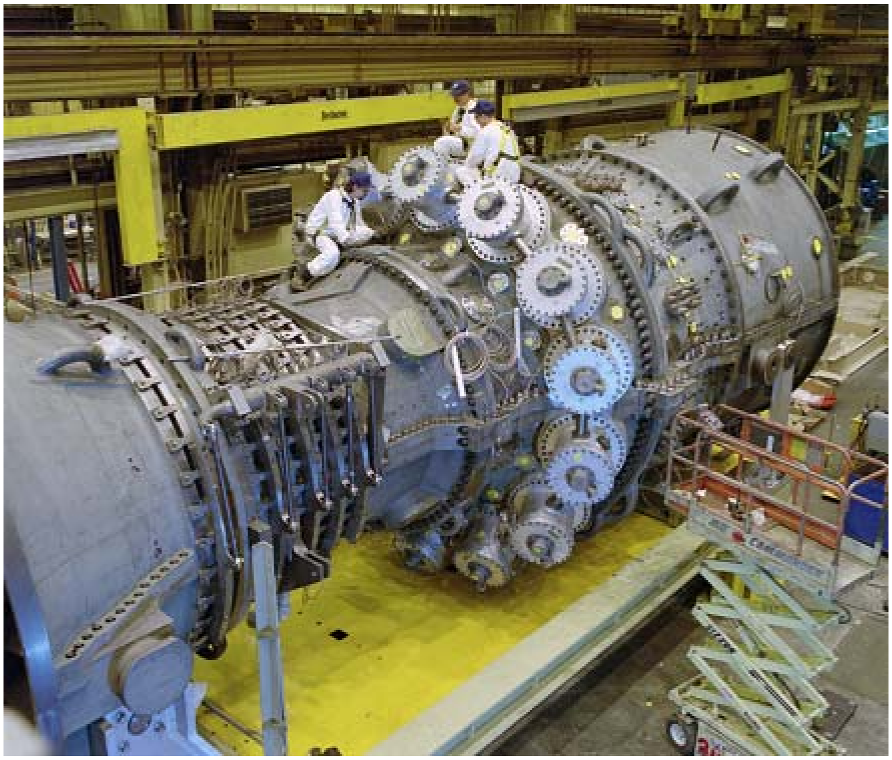


Fig. 15. GE-9H gas turbine is prepared for testing (Source: GE Power Systems)

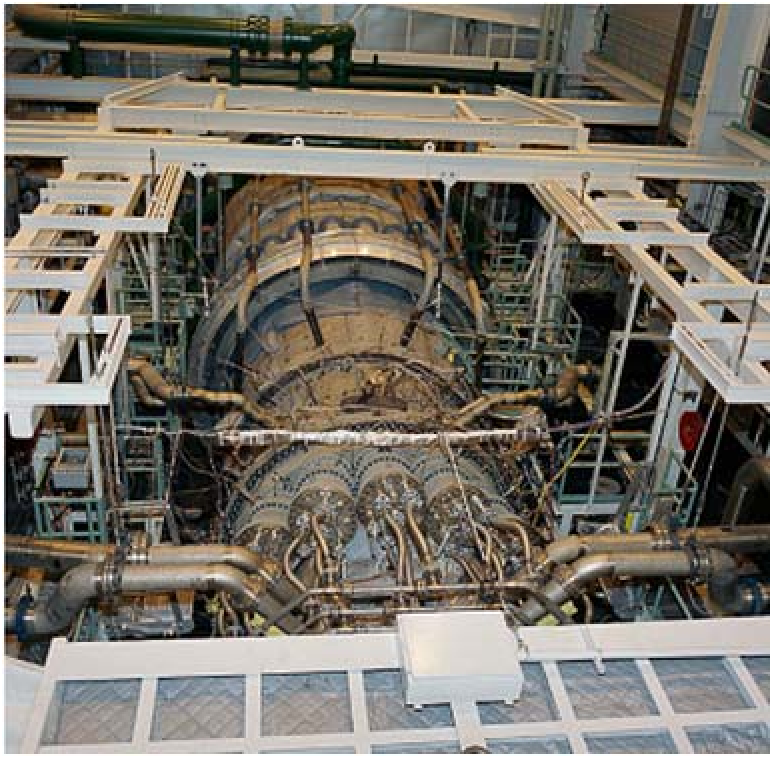


Fig.16. A GE Frame 9H during test/manufacture. (Source: GE Power Systems)

Figure 17 shows an industrial gas turbine on a trestle in preparation for shipping.

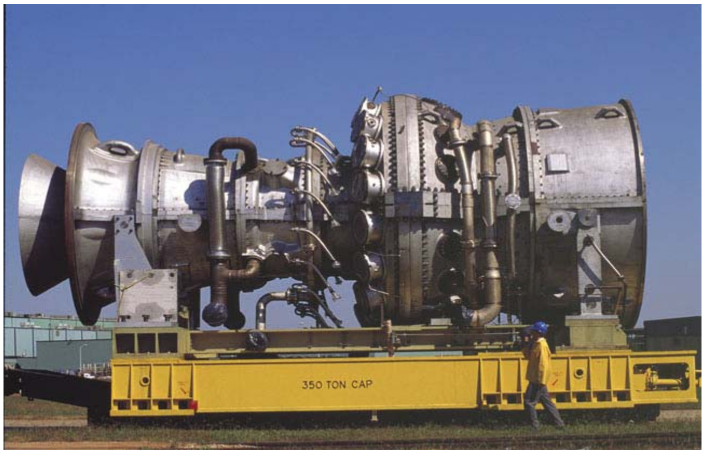


Fig. 17. A GE Frame 9F ready for shipping. (Source: GE Power Systems)

Figure 18 shows a large GE Frame 7F industrial gas turbine on a test bed in the OEM's facility.

Fig.18. GE Frame 7F during manufacture/test showing rotor in half the casing (Source: GE Power Systems)

Applications versatility of the gas turbine

The gas turbine's operational mode gives it unique size adaptation potential. The largest gas turbines today are over 200 MW (megawatts) which then places gas turbines in an applications category that until recently, only steam turbines had owned.

The smallest gas turbines are microturbines. The smallest commercially available microturbines are frequently used in small power generation (distributed power) applications and can be as small as 50 kW (kilowatts). Work continues on developing microturbines that will be thumbnail size. The world of "personal turbines" where one might plug this turbine into a "drive slot" in their car, come home from work and plug it into a "household slot" for all one's household power, is a discernable, if as yet unpredictable, target.

The content on this CD deals mainly with power generation, however with the gas turbine, understanding its origins and other applications, gives the gas turbine community a better handle on optimized design, operation and maintenance. Gas turbines came into their own in the Second World War In peacetime; NASA took over the research that led to better alloys, components, and design techniques. This technology was then handed down to military aviation, and eventually commercial aviation. However, since the same manufacturers also make gas turbines for land and marine use, aeroderivative gas turbines were a natural offshoot of their flying forerunners.

However, the same manufacturers also make gas turbines for land and marine use. So aeroderivative gas turbines were a natural offshoot of their flying forerunners.

Aeroderivative gas turbines are essentially aviation gas turbines that are installed on a light frame and installed on a flat surface (ground based, marine craft or offshore platform). Aeroderivatives are commonly used in power generation service, particularly where a relatively light package is required, such as in offshore service.

The Rolls Royce Spey and Olympus engines for instance, are both aero engines but are also popular when packaged as aeroderivatives in land based and offshore platform service.

Pratt and Whitney's (PW) JT- 8D was once the largest (in terms of fleet size) aircraft engine family in existence. The engine first made its appearance in the 1950s and delivered about 10,000 pounds of thrust, then. Several variations on the basic core produced a version that delivered roughly 20,000 pounds of thrust about twenty years later. This incremental power development around the same basic design is common and saves on development costs, spares stocking costs and maintenance. PW's FT- 8D is their aeroderivative equivalent used in both power generation and mechanical drive application.

Similarly General Electric's (GE's) LM2500 and LM6000 family (aero derivative) are essentially CF6-80C2 (aero) engines that have been adapted for land based use. What was ABB's GT35 (land based), then Alstom's GT35 (change of corporate ownership), then Siemens Westinghouse's SGT500 (yet another corporate purchase) is another example of an aeroderivative. Most aeroderivatives can also be used in marine (ferry, ship) applications. Some of them are also used on mobile land applications, such as in military tanks.

Aero and aeroderivative gas turbine engines are likely to be built in modular construction. This means that one module of the gas turbine engine may be removed from service and the other modules left in place. A substitute module may be inserted in place of the removed module so the gas turbine can resume service. An industrial engine is more likely to be constructed in a non-modular format. If part of an industrial engine has serious problems, it is likely that the entire engine will be "down for maintenance".

The term "industrial" gas turbine implies a heavier frame and a gas turbine model that was not intended for service where the mass (weight) to power ratio (in other words weight minimization for the power plant) was of paramount concern. That said, the metallurgical selections for contemporary industrials reflect the best developments in metallurgical selections. The gas turbine field is a highly competitive one, and the highest turbine inlet temperatures (TITs) that can be tolerated by the metallurgical and fuel selections, are sought as this optimizes the gas turbine's peak power rating. In other words, GE's industrial Frame 7s and 9s (be they "- F", "- G" or "- H" technology) may incorporate similar metallurgy to that used on their aircraft engines. The letters F, G and H refer to temperature ceilings and therefore imply higher power (with "later" alphabet letters).

Some turbine model designations can appear confusing due to several changes in corporate ownership. This is partly due to the fact that the OEM (original equipment manufacturer) gas turbine scene changes constantly with corporate mergers, partial mergers, buyouts of specific divisions and joint ventures. This section and the one on combined cycles therefore have several notes about specific engines' model designation history and previous ownership. This has considerable relevance when it comes to noting the finer points of any gas turbine's design. This is critical to operators as they can then make better decisions regarding the overhaul, performance optimization, component updates and retrofit systems on their turbine systems.

Any application of a gas turbine could have a great deal to offer end-users in other industrial sectors. Power generation is often the least demanding application for a given gas turbine, unless it used in variable load/ peaking service. Mechanical drive units are more likely to experience load swings. One example would be turbines driving pumps that injects (into the soil) varying volumes of sea water that accompany "mixed field" (oil, gas and seawater deposits) oil and gas production.

Aircraft engine turbines may see varying stresses depending on their service. If for instance, one considers an aerobatic squadron, one needs to be aware that the engines on the planes trying to stay a fixed distance from the wing tip of the formation's leader may accumulate life cycle losses of twenty times that of the formation leader's engines.

In other words, the variations in all parameters that pertain to a gas turbine's overall life, component lives or time between overhauls (TBOs) offer insight to gas turbine operators regardless of whether that turbine operates in "their" industry or not. Lessons which are learned in one sector of industry on gas turbine metallurgy and operating systems, such as controls or condition monitoring, can be applied in some way, to other gas turbine applications.

The History of the Gas Turbine

The development of the gas turbine took place in several countries. Several different schools of thought and contributory designs led up to Frank Whittle's 1941 gas turbine flight. Despite the fact that NASA's development budget now trickles down to feed the improvement of flight, land based and marine engines, the world's first jet engine owed much to early private aircraft engine pioneers and some lower profile land-based developments.

The development of the gas turbine is a source of great pride to many engineers world wide and, in some cases takes on either industry sector fervor (for instance the aviation versus land based groups) or claims that are tinged with pride with one's national roots. People from these various sectors and subsectors can therefore get selective in their reporting.

So for understanding the history of the gas turbine, one would have to read several different papers and select material written by personnel from the aviation, and land-based sectors. At that point, one can "fill in the gaps".

What follows therefore are two different accounts of the gas turbine's development. Neither of them is wrong. The first of these presents an aircraft engine development perspective. *

* Reference: "The History of Aircraft Gas Turbine Development in the United States", St. Peter, J., Published IGTI, ASME, 1999.

Attempts to develop gas turbines were first undertaken in the early 1900's, with pioneering work done in Germany. The most successful early gas turbines were built by Holzwarth, who developed a series of models between 1908 and 1933. The first industrial application of a gas turbine was installed in a steel works in Hamborn, Germany, in 1933. In 1939 a gas turbine was installed in a power plant in Neuchâtel.

1931 U.S. army awards GE a turbine-powered turbosupercharger development contract

1935 U.S. Army, Northrop, TWA, and GE combine to test fly a Northrop Gamma at 37,000 feet from Kansas City to Dayton. This led to a production contract for GE to build 230 units of the "Type B" supercharger and led to establishment of the GE Supercharger Department in Lynn, Massachusetts (later the site of the I-A development based on the Whittle engine).

1938 Wright Aeronautical Corporation designs its own vaned superchargers for its own engines, although the superchargers were manufactured for Wright by GE.

1940 NACA joins with Wright, Allison and P&W to standardize turbo supercharger testing techniques.

1925 R.E. Lasley of Allis-Chalmers receives the first of several patents on gas turbines.
Around 1930 he forms the Lasley Turbine Motor Company in Waukegan, IL. with the goal of producing a gas turbine for aircraft propulsion.

1934 U.S. Army personnel from Wright Field visit Lasley's shop and inspected his hardware and the engine which he had filmed in operation earlier that year. However, neither the Army nor Navy would fund Lasley.

1939 GE studies gas turbine aircraft propulsion options and concludes the turbojet is preferable to the turboprop. Note, however, that two years later they changed their minds and proposed a turboprop to the Durand Committee.

1941 GE Steam Turbine Division (Schenectady) participates in the Durand Special Committee on Jet Propulsion and proposes a turboprop, designated the TG-100 (later the T31), which ran successfully in May 1943 under Army sponsorship.

1941 GE Turbo Supercharger Division (Lynn, Massachusetts) receives the Whittle W.1.X engine and drawings for the W.2.B improved version. A top secret effort begins to build an improved version, known as the I-A, for flight test in the Bell P-59.

1941 Durand Committee also awards Navy contracts to Allis-Chalmers and Westinghouse. The Westinghouse W19, a small booster turbojet, resulted from this but Allis-Chalmers dropped out of the "gas turbine race" in 1943.

1942 In April, the GE I-A runs for the first time in a Lynn test cell. In October, it powers the Bell P-59 on its first flight at Muroc Dry Lake, CA.

1929 Haynes Stellite develops Hastelloy alloy for turbine buckets, allowing operation up to gas temperatures of over 1800 F. This superior alloy was later crucial to the successful operation of the I-A and it gave U.S. turbine manufacturers the ability to use uncooled designs rather than include the complexity of blade cooling.

By the latter part of 1942, the following “native” aircraft gas turbine efforts were proceeding. These projects included:
1. Northrop Turbodyne turboprop
2 .P&W PT-1 turboprop
3. GE/Schenectady TG-100 turboprop
4. Allis-Chalmers turbine-driven ducted fan
5. NACA piston-driven ducted fan
6. Westinghouse 19A turbojets
7. Turbo Engineering Corporation’s booster-sized turbojet

The following timeline contains many of the relevant land based gas turbine design developments. *
Note that this also contains some timeline references to aircraft engine development.
* Reference: ASME 2001 - GT- 0395 “Advanced gas turbine technology – ABB/ BBC historical firsts” by Eckardt, D., and Rufli, P., ALSTOM Power Ltd.
Note: BBC = Brown Boveri Company, ABB = Asea Brown Boveri

Switzerland *(& Swiss Abroad)*

1921 J. Ackeret, high-speed aerodynamics scientist at ETH Zurich, arrives at L. Prandtl’s AVA Aerodynamische Versuchs-Anstalt Gottingen; stays seven years

1925 CEM (G. Darrieus) - a French subsidiary of BBC (Brown Boveri Company) produces a series of windmills, using airfoil design theory.

1926 BBC’s 4 stage axial test compressor designed, first with untwisted blades, later swirl adapted.

1932 BBC sold a number of 11 stage axial compressors, PR= 3.4, for the Mondeville project and high-speed windtunnels at ETH-Zurich and Rome.

1934 C. Keller, assistant to J. Ackeret at ETH Zurich, designed one of the windtunnel blowers (2nd blower for high speed tunnel came from BBC).

1939 A. Meyer, BBC’s Technical Director, presents a comprehensive paper on GT design achievements (including GT usage for compact & lightweight ship/destroyer propulsion) at the Institute of Mechanical Engineering, London
• First commercial industrial GT from BBC is operational at Neuchatel
• BBC delivers 1st Industrial GT to RAE, 1.6 MW 20 stage axial compressor
• In 1940 BBC delivers axial aircraft superchargers, 190 hp, PR=2.5 to complete a RR purchase order

Germany *(& Germans Abroad)*

1922 W. Bauersfeld suggests the use of airfoil theory for fluid machinery

1935 At AVA Gottingen, a 4 stage axial turbocharger, 7 stage compressor design undergoes development (Encke et al. design), PR=3.8 [in production PR=3.1].

1935 H.P. von Ohain gets a secret turbo-engine patent no.317/38

1937 H.P. von Ohain’s test engine HeS313 runs

1939 The first jet-powered flight He 178 aircraft with HeS313, on Sunday Aug 27, 1939.

• R. Friedrich, Junkers Magdeburg, design the 14 st. axial compressor for the “RTO” engine (Riickstoss-Turbine ohne Leistungsabgabe with a Propeller), for the Helium aircraft S30 engine, based on Gottingen airfoil design

1942 Me 262 fighter aircraft entered service with two Jumo 004 engines, first test flight on August 18.

England *(& English Abroad)*

1926 A.A. Griffith releases “An Aerodynamic Theory of Turbine Design”, which discusses a GT as an aircraft’s power plant

1930 F. Whittle gets the first patent for a turbo aeroengine
• Tizard, Gibson & Glauert committee denies that the gas turbine could be superior to the piston engine

1937 F. Whittle, radial compr. engine, test run on December 4

1938 A delegation at BBC decides that “Exclusivity on the BBC (axial) compressor design would not be granted”

1941 The Whittle engine has its first flight

Note that in the early 1930s, BBC designed components used for the Velox project boilers. They developed a turbine that had enough power to drive the compressor, and could also generate excess power through the inverse operation of the electric starter motor. Also, in 1936, BBC’s '34MW all-axial process gas turbine/ blower train with a PR = 4, was supplied to a US refinery.

In July 1939, BBC commissioned the world’s first utility gas turbine at Neuchatel, Switzerland. The gas turbine had one 23 stage axial compressor, one single-can combustor, one 7 stage axial turbine, and a synchronously operated generator on the same shaft.

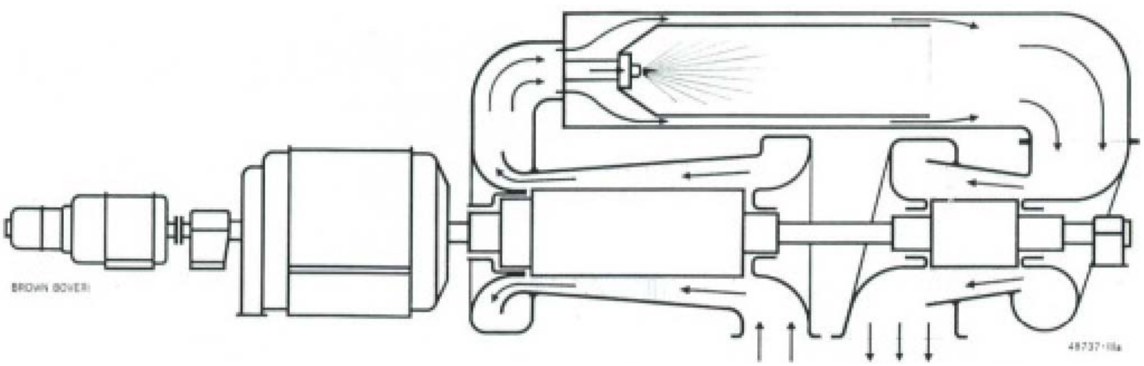


Fig. 19. BBC - First Utility GT Power Plant, 4 MW, Neuchatel, Switzerland, 1939 (courtesy Alstom Power)

Gas Turbine Major Components, Modules, and Basic Systems

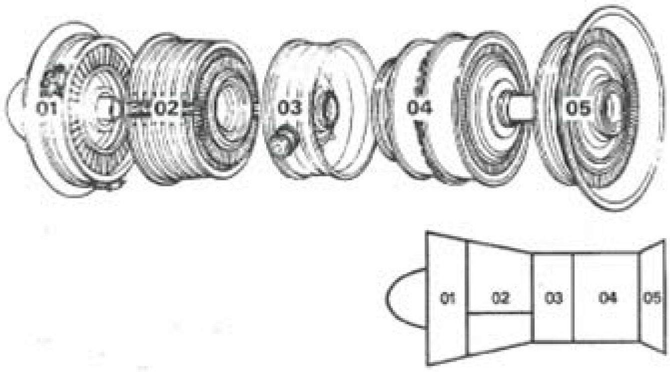


Fig. 20. Modules in a gas turbine Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce UK

Primary Modules

The primary modules in a gas turbine are the:
• Compressor module
• Combustion module
• Turbine module

A gas turbine also has an inlet section/ module and an exhaust section/ module. See Figure 20.

Most advanced and large gas turbines have compressors that are the axial design type. Some of the earlier, smaller or deliberately compact gas turbines have centrifugal compressors. See Figures 21, 22, 23.

Each compressor stage provides an opportunity for stepping up the overall compressor pressure ratio (PR), so although an axial stage may not offer as much of a PR as a centrifugal stage of the same diameter, a multistage axial compressor offers far higher PR (and therefore mass flow rates and resultant power) than a centrifugal design.

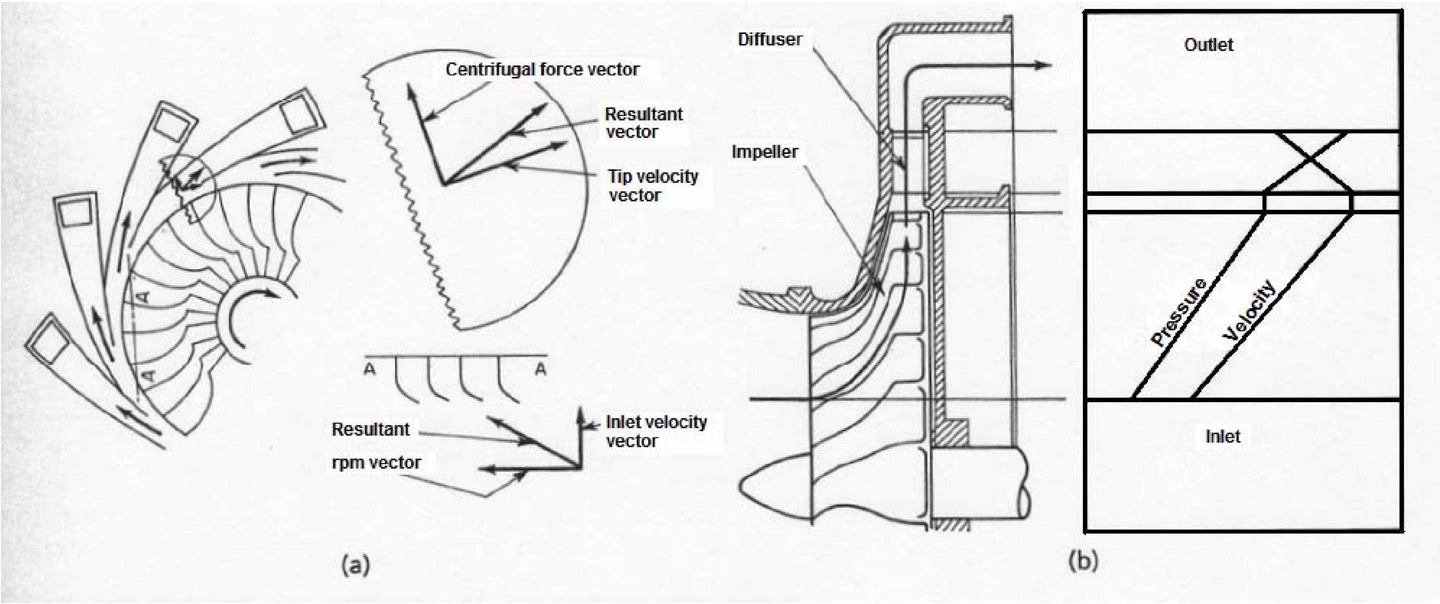


Fig. 21. Centrifugal-compressor flow, pressure, and velocity changes
(a) Airflow through a typical centrifugal compressor,
(b) Pressure and velocity changes through a centrifugal compressor.
Courtesy Rolls Royce UK

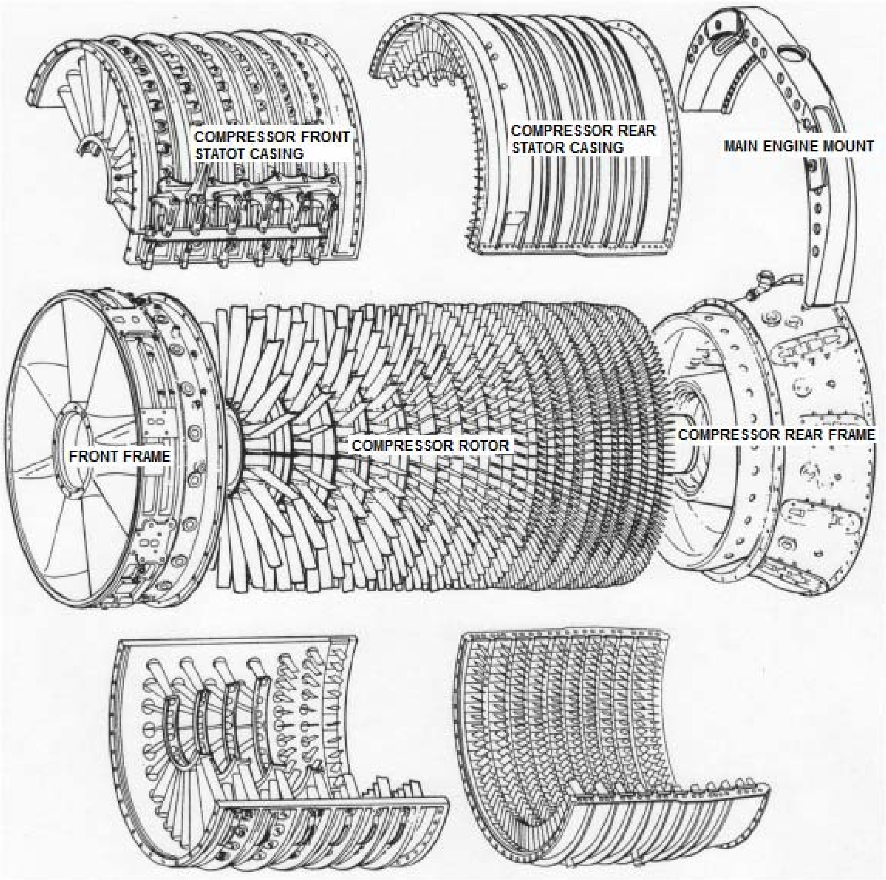


Fig. 22. A modern high-performance compressor assembly.
(General Electric) (Source: “Aircraft Gas Turbine Engine Technology” McGraw Hill)

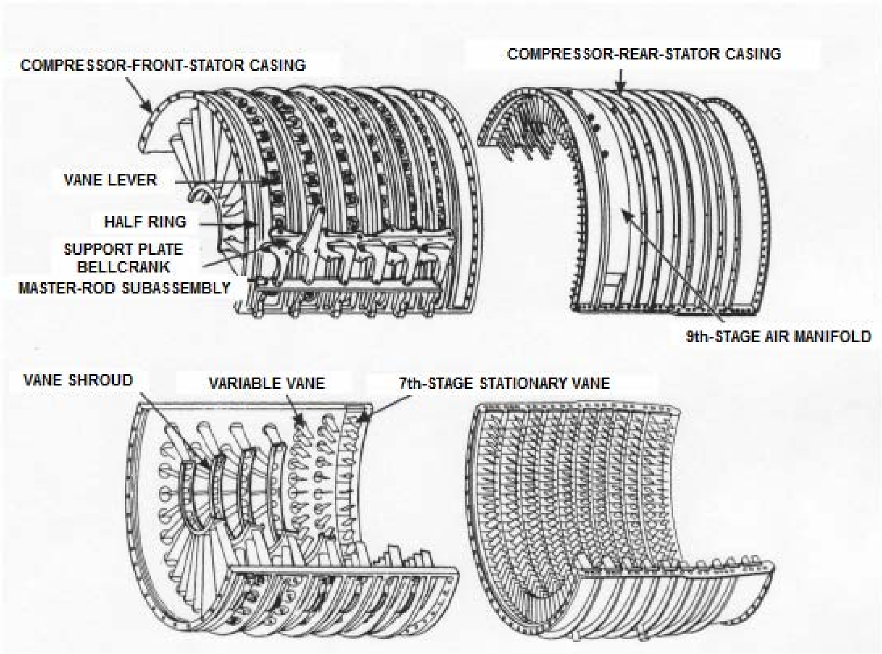


Fig. 23. Stator case for the General Electric 179 engine.
(Source: "Aircraft Gas Turbine Engine Technology" McGraw Hill)

Therefore most gas turbine designs incorporate axial compressors. In newer designs, the compressor and turbine modules may be split into further submodules, to lessen the stress on individual components and achieve better efficiencies.

So a compressor may have a low pressure (LP) module or LPC, and a high pressure module (HPC). In this case there will be equivalent high and low pressure turbine modules (LPT and HPT). The LPC and LPT will operate on one long shaft at the same speed. The HPC and HPT will operate on a shorter shaft that fits around and concentric to, the low pressure shaft, and at a higher speed than the low pressure module. See Figure 21.

Some contemporary gas turbines have three modules, designated low, intermediate and high pressure, each with their own shaft.

This modular concept allows for module replacement or exchange, if maintenance to a module is required, without taking the entire gas turbine out of service.

Module component aerodynamic and thermodynamic basics

Air inlet section

A gas turbine takes in many multiples of what an equivalent size reciprocating engine can. The air inlet is generally a smooth, bell shaped, aluminum alloy duct. It leads air into the compressor with minimized turbulence. Typically, struts brace the outer shell of the front frame to minimize air flow vibration.

An anti-icing system directs compressor air (at discharge or some pressure higher than atmospheric) that is bled off an appropriate compressor stage, into these struts. The temperature of this air prevents ice formation. Ice ingestion can and has destroyed many gas turbine engines.

Compressor module

The compressor is made up of rotating blades on discs and stationary vanes that direct the air to the next row of blades. The first stage compressor rotor blades accelerate the air towards their trailing edges and towards the first stage vanes. The first stage vanes slow the air down and direct it towards the second stage compressor rotor blades, and so on through the compressor rotor stages (each stage is one rotating stage and one stationary stage).

Then air enters the diffuser section. The highest total air velocity and maximum compressor pressure is at the inlet of the diffuser. Air moves through the diffuser, which presents the air with an increasing cross sectional area, so the air's velocity decreases and the static pressure increases. The highest static pressure is at the diffuser outlet.

The compressor rotor can be described as an air swallower. The volume of air swallowed by the compressor rotor is proportional to the lowest pressure (in a multiple shaft gas turbine) rotor rpm.

However, the altitude at which the gas turbine is located will alter the horsepower (for a mechanical drive) or the power (in watts, kilowatts or Megawatts) that the gas turbine develops. This is because air density decreases with altitude and with increasing air temperature and humidity. That means when the compressor swallows a certain volume of air, that air will be a smaller weight of air, if the gas turbine is at a high altitude, still less if it is a hot day, and still less if it is also a humid day. This smaller weight of air requires a smaller weight of fuel to combine with, and the mixture then produces less power when burned. Note however, that humidity, in comparison with temperature, and pressure altitude, has a much smaller effect on density.

In aircraft engine applications, with increased forward speed, ram air pressure increases and air temperature and pressure increase. Ram air pressure is defined as the free stream air pressure created by the forward motion of the aircraft engine. The effect of rise in air intake temperature on power developed by a gas turbine can be noted in figure 24.

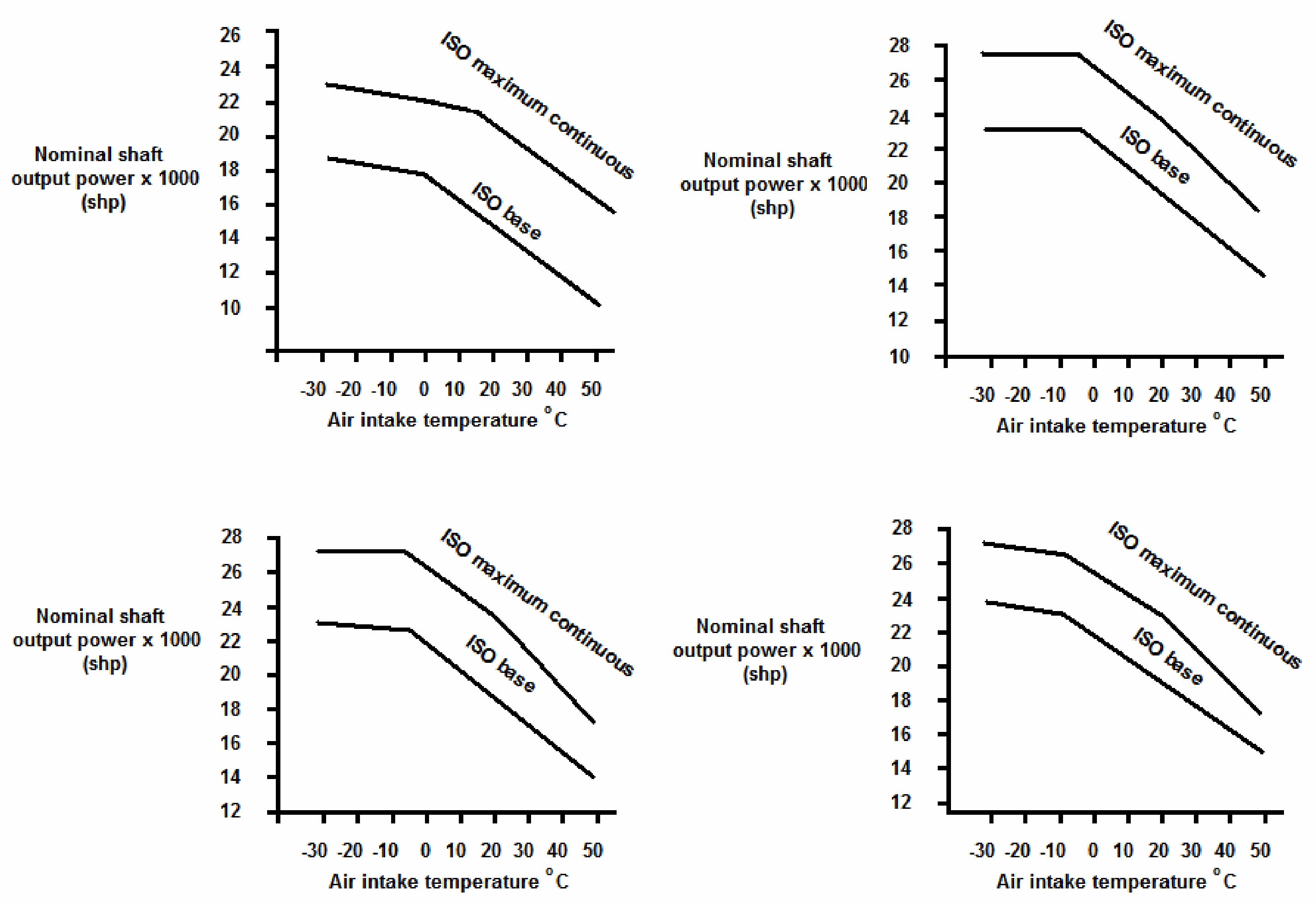


Fig. 24. Variation of shaft power with inlet air temperature for different configurations of the Rolls Royce Avon
Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares C., 1998

There are many different compressor designs that result from the manufacturer's balance of several design factors, including target gas turbine power developed, cost of manufacture, anticipated serviceability factors and so forth. As previously discussed, when the gas turbine is started up, the turbine section will keep the compressor section rotating. The compressor's efficiency is a key factor in determining the power necessary to create the pressure rise of a given airflow. This pressure rise will in turn affect the temperature difference between the compressor inlet and outlet.

As mentioned previously, the main types of compressor design are centrifugal and axial flow. The axial-centrifugal-flow compressor is a combination of both and operates with a combination of their characteristics. It is a less common design.

Centrifugal-flow compressor

As the rotor turns, air is drawn into the blades near the center of the front rotor stage. Centrifugal force accelerates this air as it moves outward from the axis of rotation towards the edge of the rotor.

It is then forced through the diffuser section at high velocity (high kinetic energy). A pressure rise results when the air slows in the diffuser (some velocity energy becomes pressure energy). One centrifugal compressor stage is capable of a relatively high compression ratio per stage. It is not practical to use on larger engines because of its size and weight, relative to axial stages.

Because of the high tip speeds it develops, the centrifugal compressor is most used on smaller engines where simplicity, flexibility of operation, and ruggedness outweigh its characteristics of less overall pressure ratio than that developed by an axial compressor.

Axial-flow compressor

The air is compressed, in a direction parallel to the longitudinal axis of the engine. Axial flow compressors consist of several stages that collectively create high compression ratios with high efficiencies. The streamlined shape of this type of compressor make is suitable for use on high speed (ram jet) aircraft. Its design is less rugged than that of the centrifugal compressor though, making it more susceptible to foreign object damage (FOD).

The required efficiency and power rating then mean that the design parameters that govern its design, such as rotor dynamics characteristics, clearances and fits, also make it more expensive to manufacture. With the rising cost of fuel, most gas turbine designers use axial compressors, as features such as power delivered per unit weight of the gas turbine outweigh initial manufacture costs.

Axial-centrifugal-flow compressor

The axial-centrifugal-flow compressor, also called the dual compressor, is a combination of the two types. Its operating advantages and characteristics are also a combination of both rotor types. It is useful is specialized application designs, such as those for US Army helicopters.

Typically the compressor is five- to seven-stage axial-flow compressor and one centrifugal-flow compressor. The compressors are mounted on the same shaft and therefore turn in the same direction and at the same speed. The centrifugal compressor is situated aft of the axial compressor stages.

Most high performance gas turbines today also have inlet guide vanes (IGVs) and/ or variable inlet guide vanes (VIGVs) at the compressor inlet. This is to ensure that the air flow hitting the rotor blades does so at an acceptable angle of attack that does not cause the blade to stall.

If we consider a cross section through the wing of an aircraft, we note that the section is similar in shape (if not size) to that of an airfoil in a gas turbine. All airfoils provide lift by producing a lower pressure on the convex (suction) side of the airfoil than on the concave (pressure) side. With any airfoil, lift increases with an increasing angle of attack, but only up to a critical angle. Beyond this critical angle of attack, lift falls off rapidly. This is due mostly to the separation of the airflow from the suction surface of the airfoil.

In simpler terms, we know that when the cushion of air under the aircraft wing is reduced to a certain level, the wing has inadequate lift. It (and the aircraft) tend to drop from their existing level. The airfoils in a gas turbine can stall in exactly the same way, one blade at a time. If a whole row of blades stalls, we have a condition called rotating stall, at which point surge occurs. Surge causes a rotor to go back on itself, in an attempt to regain the lift under the airfoil. In flight, the pilot then pushes the nose down to recover from stall, as this then restores the air cushion under the wing.

Combustor module

There are three main combustion chamber types in use today (See figures 25-29):
• annular combustor chambers
• can (multican) combustor chambers
• can-annular combustor chambers

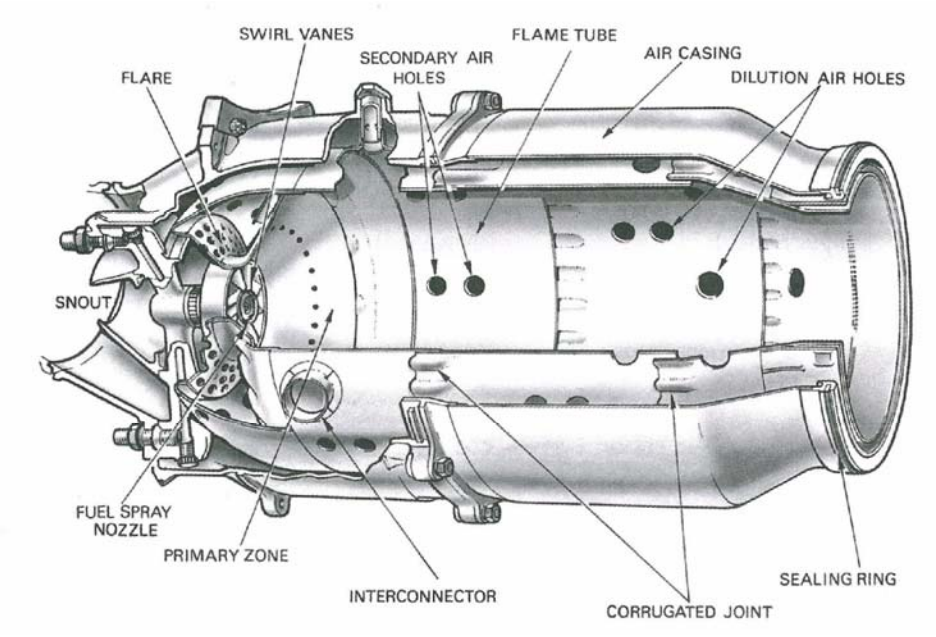


Fig. 25. A combustion chamber. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd Edition, Bloch, H. and Soares, C., 1998

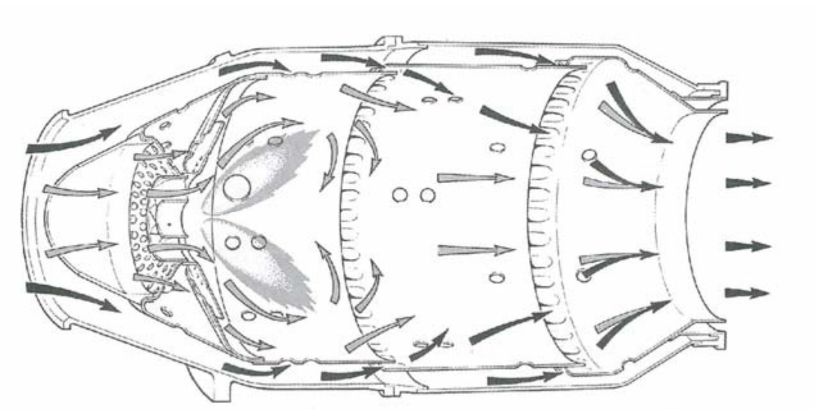


Fig. 26. Flame stabilizing and general airflow pattern. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd Edition, Bloch, H. and Soares, C., 1998,

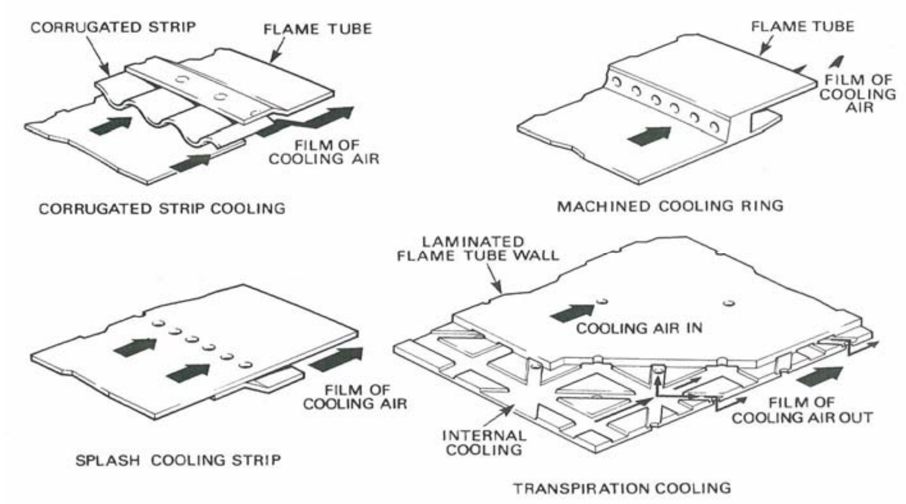


Fig. 27. Flame tube cooling methods Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd Edition, Bloch, H. and Soares, C., 1998

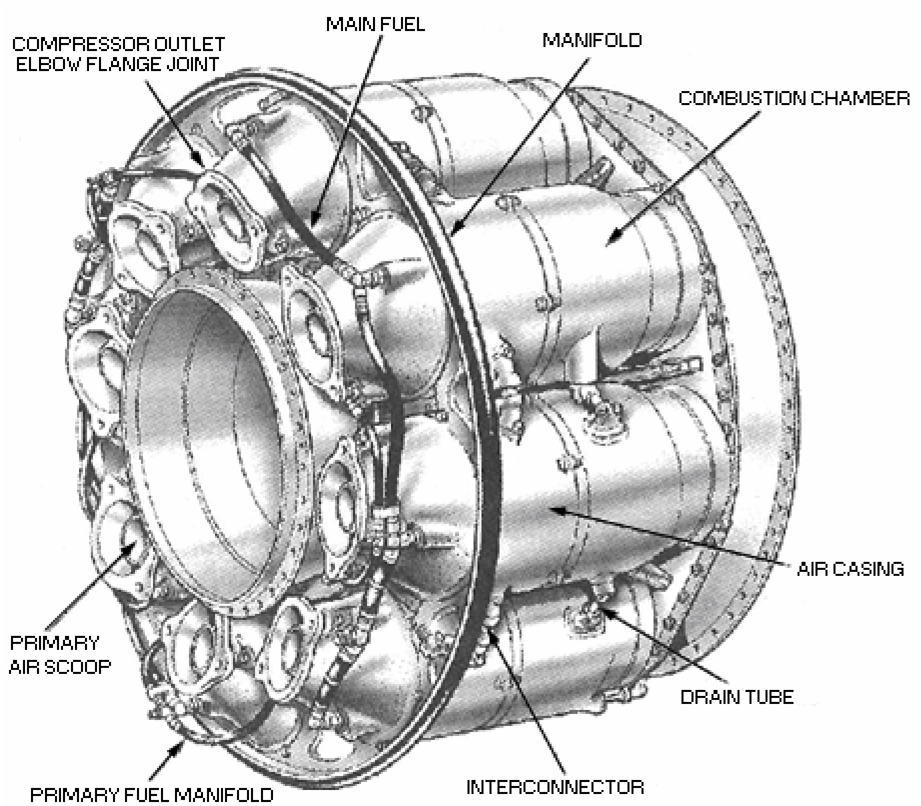


Fig. 28. Multiple Combustion Chambers Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd Edition, Bloch, H. and Soares, C., 1998

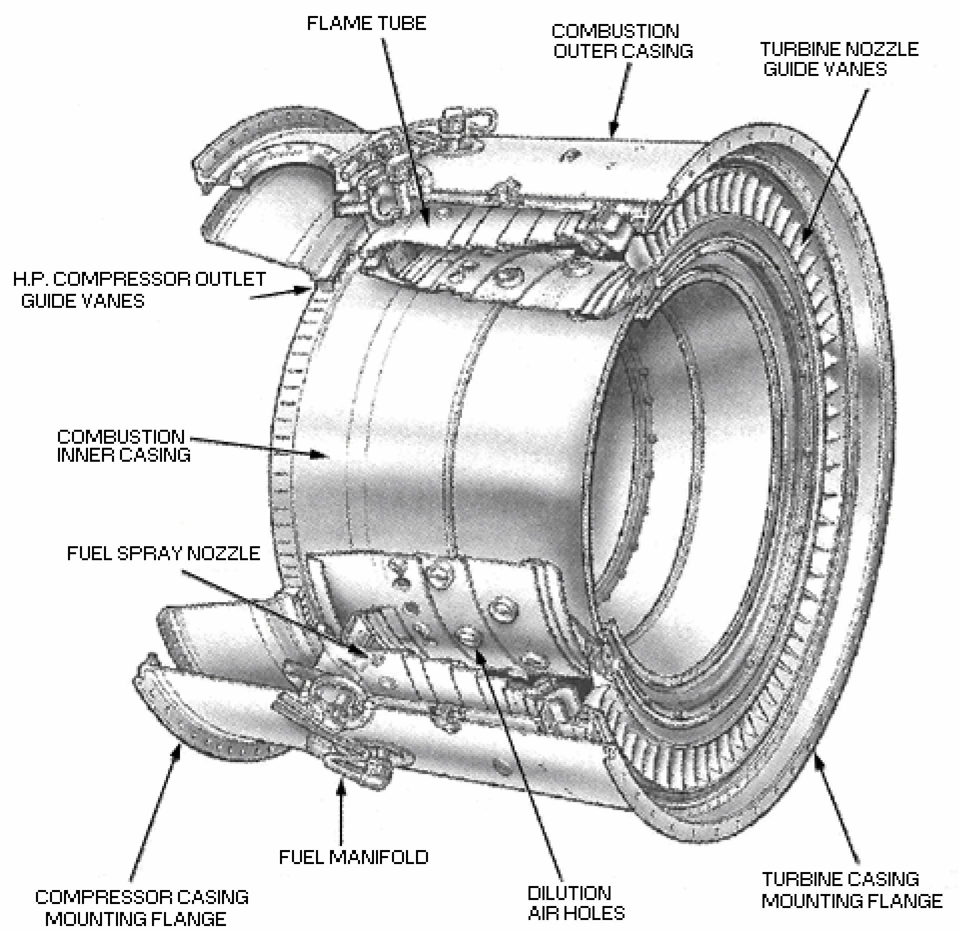


Fig. 29. Annual Combustion Chambers Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd Edition, Bloch, H. and Soares, C., 1998

Some variations on these basic designs occur in specialized applications. Again, one example is US Army helicopters that use the annular reverse-row type.

The combustor module contains the combustion chambers, igniter plugs, and fuel nozzles. The combustor burns a fuel-air mixture and delivers the products of combustion to the turbine at temperatures within design range.

Fuel is injected at the upstream end of the burner in a highly atomized spray. Fuel nozzles may be simplex type (delivering gaseous fuel or liquid fuel) or they may be designed to be dual fuel (delivering gas or liquid at different times in the operation). Some gas turbines are "bi-fuel". They may burn a mixture of gas and liquid fuel.

Combustion air, with the help of swirler vanes, flows in around the fuel nozzle and mixes with the fuel. This air is called primary air and represents approximately 25 percent of total air ingested by the engine. The fuel-air mixture by weight is roughly 15 parts of air to 1 part of fuel. The remaining 75 percent of the air is used to form an air blanket around the burning gases and to lower the temperature.

Flame temperatures in excess of 3600° F (roughly 200 degrees C) are not uncommon in high performance aircraft engines. Cooling air drops this temperature to a value that the turbine inlet guide vanes can withstand. The air used for burning fuel is "primary" air. Cooling air is "secondary" air and is controlled and directed by holes and louvers in the combustion chamber liner.

Certain aircraft engines are termed high bypass ratio fan engines. With this design, the gas turbine has an inlet fan upstream of the low pressure compressor (LPC). That fan's diameter is far larger than that of the LPC. Much of the air ingested by the fan is directed through an annular sleeve type casing that fits around the compressor. This bypass air provides still more cooling but also helps with other gas turbine performance characteristics like power developed, total mass flow and FOD ingestion capabilities.

As we read previously, igniter plugs function during start up and are cut out of the circuit as soon as combustion is self supporting (the turbine has developed design speed and is driving the compressor on its own).

On engine shutdown, or, if start failure occurs, the combustion chamber drain pressure-actuated valve, automatically drains any raw fuel from the combustion chamber.

The material suitable for fabricating the combustion chamber liner is typically welded high-nickel steel. The hottest zone is about the first upstream third of its length (flame zone). The most severe operating periods in combustion chambers are during engine idle (reduced air) and maximum rpm (power) operation. Sustained operation is generally unnecessary. "Base load" with a ground based gas turbine is generally a power setting lower than this value. With aircraft engine operation, maximum rpm generally corresponds to maximum (take off) thrust.

The annular combustion chamber can enhance a geometrically compact design. Instead of individual combustion chamber cans, compressed air is introduced into an annular space formed by a chamber liner that may be situated in some designs, around the turbine assembly. Annular space left between the outer liner wall and the combustion chamber housing conducts the flow of compressor secondary cooling air. Primary air is mixed with the fuel for combustion. Secondary (cooling) air reduces the temperature of the hot gases seen by the turbine first stage inlet nozzle guide vanes (IGVs). An annular combustion chamber provides a larger combustion volume per unit of exposed metal area and therefore of metal weight.

The can combustion chamber design has individual combustion chambers. Air from the compressor enters each individual chamber through a transition section. Each individual can has two cylindrical tubes, concentric in most locations, the combustion chamber liner and the outer combustion chamber. Combustion occurs within the inner liner. Louvers and holes control airflow into the combustion area. Continuous airflow helps prevent carbon from forming on the inside of the liner. Carbon deposits can cause hot spots or block cooling air passages, which then shortens burner life.

Ignition occurs during the start cycle. The igniter plug(s) is (are) located in the combustion liner adjacent to the start fuel nozzle. Two is a typical number. The flame lights off in the can closest the igniter and cross tubes rapidly conduct the flame to the other combustion cans.

Some engines use a single can combustor. In the case of the illustration below, because of the size of the single can, the design is referred to as a "silo" burner. This design can be vulnerable to one or more of the heat shield tiles that line the inside of the silo, breaking loose and potentially proceeding downstream into the turbine's gas path.

Fig. 30. GE 9H partial combustion module during manufacture (Source: GE Power Systems)

Can-annular combustion chamber
This combustion chamber is a combination of both annular and can-type designs. The can-annular combustion chamber consists of an outer shell (annular), with a number of cans (can type) mounted about the engine axis. The combustion chambers are cooled by air that enters the liners through various holes and louvers. This air is mixed with fuel from the fuel nozzles. The fuel-air mixture is ignited by igniter plugs, and the flame is then carried through the crossover tubes to the remaining liners.

Fig. 31. DLN (dry low NOx) combustor
(Source: GE Power Systems)

The inner combustion chamber casing serves as structural support and a heat shield. Bearing oil supply lines run through it.

Low NOx combustors
As previously noted, raising the temperature at which the combustion gases enter the turbine (turbine inlet temperature or TIT), will also raise the efficiency of the gas turbine cycle. Care has to be taken however, that an increase in TIT does not cause other operational problems, such as overheating of turbine components and turbine lubrication oil. If the TIT increase is not accompanied with sufficient additional cooling, this could happen.

Also, one needs to consider that the amount of oxides of nitrogen (NO_x) produced by a combustor increases with the value of the flame temperature in the combustor and the corresponding value of TIT. NO_x emissions contribute to acid rain and legislation against NO_x production has become increasingly stringent. Hence lower TITs, to the extent permitted by optimized efficiency, are desirable.

This fact needs to be kept in focus when selecting and/or specifying gas turbines for particular applications and specific demographics (i.e. country or state concerned and their particular legislation). Two examples of low NO_x combustors are shown in Figures 33 and 34.

Fig. 32. The SGT-600 dry, low-emission (DLE) combustion system
Source: Siemens Westinghouse

The SGT-600 fleet has clocked up one and a half million operating hours with its dry, low-emission (DLE) combustion system, which significantly reduces environmental impact. The DLE combustion system was developed for the SGT-600 in 1990 (original design developed by ABB, later Alstom Power, then acquired by Siemens Westinghouse). The SGT-600 burner lowers NO_x by reducing the flame temperature in its combustion chamber. The SGT-600 annular combustor has a total of 18 burners. Each burner consists of a cone split in two halves, which are slightly offset to form two slots for the combustion air to enter (original Alstom designation was the "EV" burner). The main gas supply also enters through these slots, via tubes fitted along them. Primary fuel is injected at the tip of the cone. This results in a richer fuel mixture, enabling a control feature to stabilize the flame over a range of load conditions. Further combustion control can be provided by means of an optional bypass system that allows the amount of dilution air to be varied.
The current design achieves NO_x emission levels of less than 25 ppmv (at 15% O_2), operating on natural gas in 50-100% load range. Single-digit NO_x levels have been measured in some plants. The DLE system for the SGT-600 has been operating successfully in a variety of applications, including mechanical drives for pipeline and gas storage compressors; cogeneration for industrial duty as well as municipal district-heating systems; and power generation, in both combined-cycle and simple-cycle operation. Installations cover a range of environments, including offshore, from arctic to tropical, at altitudes of up to 1500 meters. Although DLE technology is suitable for dual-fuel combustion, water injection is required to reduce NO_x emissions when burning liquid fuel. Emission levels for operation on liquid fuel are below 42 ppmv, at full load, with a modest water-to-fuel ratio of 0.8.

Low NOx combustors are designed, optimized and promoted extensively for both performance and profit-based reasons. The extent of the profit they represent varies with the demographics of the location in question. Specifically:

1. In the U.S., as flameless combustor designers are quick to point out, their ultra low single digit NO_x designs succeed in getting their operators legally permitted (to commence power production) in some cases a few months ahead of their rivals, who may have quite respectable NOx levels ranging from 9 to 15 ppm. This represents a considerable amount of revenue.

2. Both the US and Canada deal with emissions trading. Regardless of any opinion on the technical wisdom of such measures with respect to the overall atmospheric load, low NO_x abilities represents revenue to an operator who can then sell his “spare” credits.
3. In Scandinavian countries, operators pay taxes per unit weight of NO_x and SO_x emissions. This source of revenue method may spread through the western world.

4. Low NO_x means that other emissions such as CO and CO_2 are also lowered. CO_2 taxes may soon be reality in global, particularly western world terms. In this aspect, once again Scandinavian countries point the way for other operators.

5. End users may also note that reduced NOx generally means lower TITs, hence reduced wear on hot section components and therefore reduced costs per fired hour.

Fig. 33. A GE LM6000 partially assembled.
(Source: GE Power Systems)

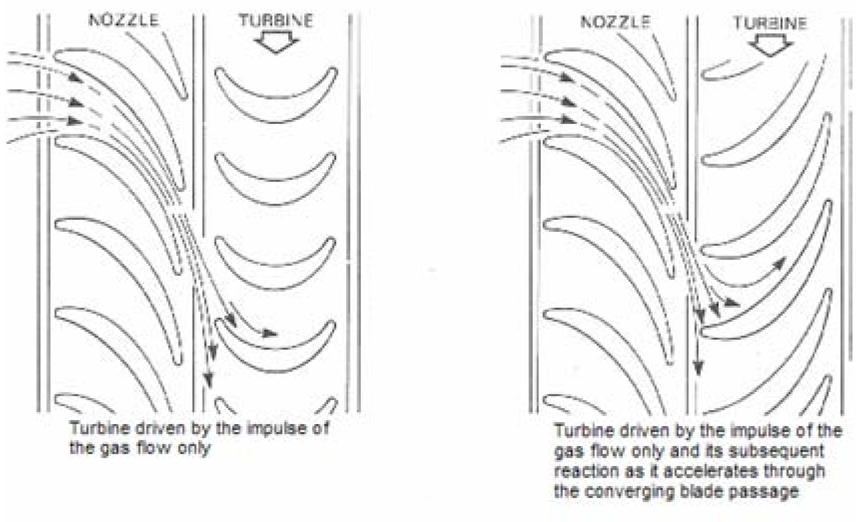
Turbine module

The kinetic energy of the gases entering the turbine is transformed into shaft horsepower (see Figures 34 through 38) which is then used to drive the compressor and other support systems (via accessory system gears. Note that this turbine, combustor and compressor modules form an assembly that is termed the “gas generator”. In power generation applications, the entire gas turbine is a gas generator that is then mechanically coupled either directly or via a gear box, to the generator that in turn is coupled to the grid or power supply system.

However, in land based mechanical drive applications, we read earlier that a free power turbine rotates downstream of the gas generator at the turbine end and that it is on a different shaft system (with or without a gear box) together with the machinery (typically compressors or pumps) it turns.

Aviation turboprop or helicopter applications have a transmission system (gearbox) that may be located at the compressor end of the gas turbine, to conduct torque to the propellers or helicopter rotors. The main turbine airfoil design type used in gas turbines today is axial flow design. Some manufacturers however, use a radial inflow design. The radial inflow turbine is rugged, less complex, less expensive and easier to manufacture than the axial-flow turbine. This radial flow turbine design is a “backwards” version of the centrifugal flow compressor. Similarly, radial turbine rotors used in small engines have a high efficiency relative to their weight and the space they occupy.

The axial flow turbine consists of stages, each made up primarily of a set of stationary vanes followed by a row of rotating blades, also on a disc. Turbine blades are either impulse or reaction type. Typically modern aircraft gas turbine blades have both impulse and reaction sections.



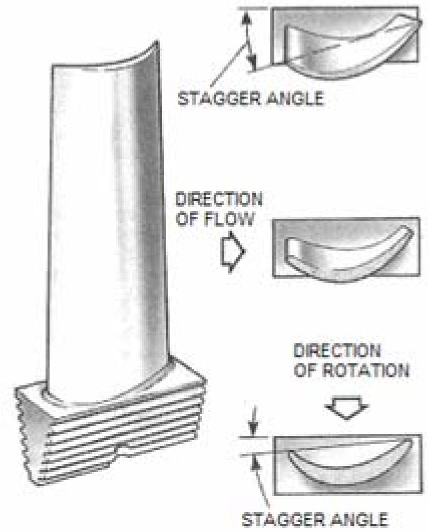
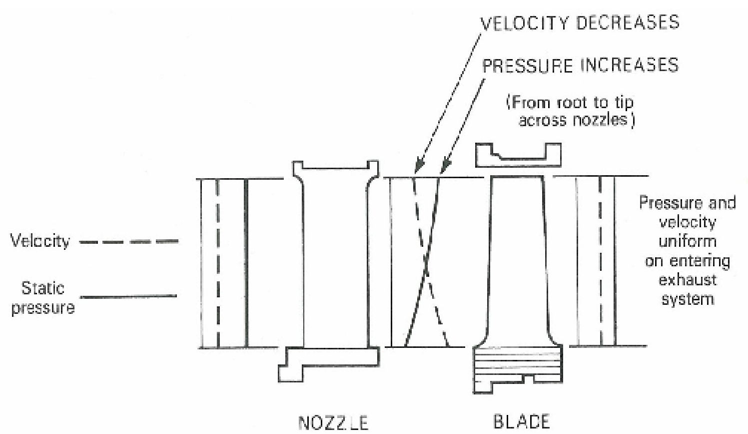


Fig. 34. Comparison Between a pure impulse turbine and an impulse/reaction turbine. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

Fig. 35. A typical turbine blade showing twisted contour. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce



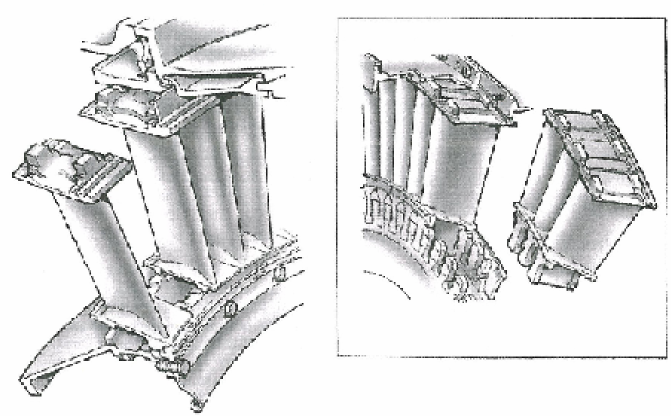


Fig. 36. Gas flow pattern through nozzle and blade. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

Fig. 37. Typical nozzle guide vanes showing their shape and location. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

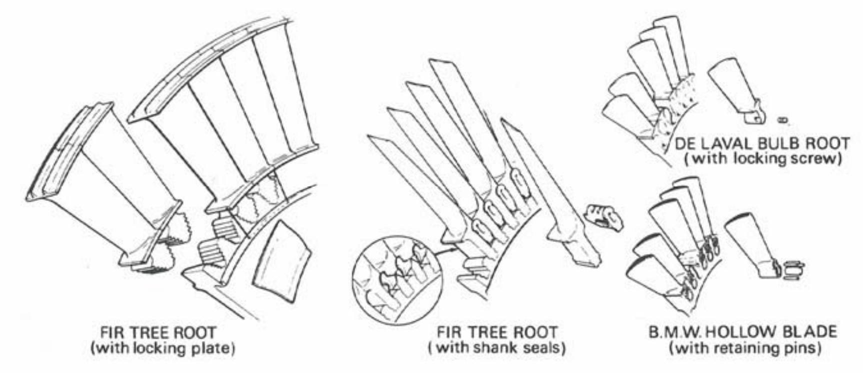


Fig. 38. Various methods of attaching blades to turbine disks. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

The stationary part of the turbine assembly consists of a row of contoured vanes set at a predetermined angle to form a series of small nozzles which direct the gases onto the blades of the turbine rotor. For this reason, the stationary vane assembly is usually called the turbine nozzle, and the vanes are called nozzle guide vanes.

Exhaust module

The gas turbine's hot gases exit via the exhaust section or module. Structurally, this section supports the power turbine and rear end of the rotor shaft. The exhaust case typically has an inner and outer housing. Hollow struts locate its position. The inner housing typically has a cone shape or cover that encloses a chamber for cooling the thrust bearing at the end of the shaft.

When we consider aircraft engine applications, we note that turboshaft engines (such as those used in helicopters) do not develop thrust with the use of the exhaust duct, as they must be capable of stationary hover. So helicopters use divergent ducts that dissipate energy in exhaust gases. On fixed wing aircraft, the exhaust duct could be convergent in design. That would accelerate exhaust gases and produce thrust which adds additional power to the engine. Combined thrust and shaft horsepower give equivalent shaft horsepower (ESHP).

Other Gas Turbine Systems

Cooling system

Air for cooling the hot sections of the turbine are drawn (bleed air) from various stages in the compressor. Most OEMs prefer to use air only for cooling, even if they have a combined cycle operation and therefore a source of steam derived from water that is boiler feed water quality. Steam cooling can be very effective, both in closed loop and open loop configurations, as some OEMs, such as MHI have proven. If the steam quality stays uniform, deposits will not form on the insides of fine laser drilled cooling holes in the turbine airfoils. However, if there is a divergence in required water/ steam quality, this could prove a problem. Other OEMs, such as Rolls Royce prefer not to worry about this possibility, however remote. They configure their designs so that they only need air cooling. See Figs 39 and 40. For a description on a successful steam cooling design, see the section on Design Development.

Air "spent" on cooling will cost the OEM in terms of nominal efficiency, so some designers are less keen to spend more than they absolutely have to. In power generation machinery that generally operates at base load, this may not be of major concern. It is, in applications with severe swings in load and/ or speed.

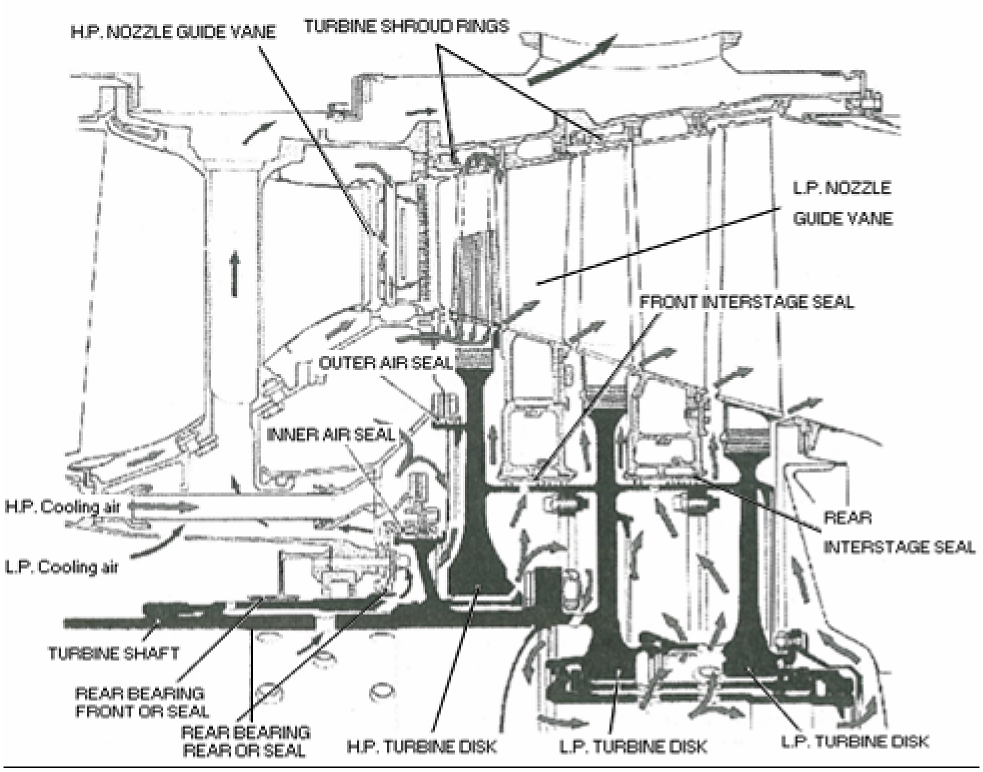


Fig. 39. Air system flow in the turbine. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

Bearing and lubrication system

Basically, sleeve bearings locate the turbine modules concentrically around the shaft(s) during operation and when the turbine is not running. They provide the rotor with support. The thrust developed by the overall rotor is absorbed by thrust bearings at the end of the rotor. One arrangement of key bearing positions is shown in figure 40.

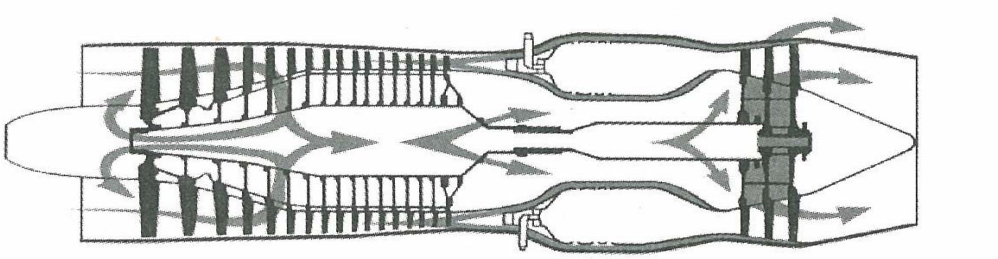


Fig. 40. Main internal air system flows. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

Oil flow to the bearings is regulated. The bearings in the hot section require far more oil flow than those in the cooler compressor section. Thermocouples or RTDs measure oil flow temperature. Sudden temperature rises in the oil trigger an alarm or shutdown.

The section on design development refers to varying design philosophies between OEMs. The lubrication system is one area where it shows as much as anywhere else. Certain OEMs have a preference for greater lubrication flows than others, at a given temperature range.

Fuel system

As we will see in the section on design development, the gas turbine can run on a very wide variety of fuels that are gaseous, liquid, atomized solid (coal) suspended in gas, or semi-solid (biomass waste liquor). Each of these different fuel types requires its own customized fuel delivery systems with varying combustor residence times. However, most OEMs have standard fuel systems for natural gas, liquid fuel (such as LNG or diesel), dual fuel (gas or liquid) and in the case of manufacturers such as Rolls Royce bi-fuel (both gas and liquid at the same time). See figures 41 through 45.

The basic principle of most gas turbines power development revolves around “temperature topping”. A fuel control unit, which in earlier gas turbines is a mechanical device with several cams and contours, controls the fuel flow. In newer engines the control is more like an electronic brain where electronic functions take the place of the mechanical cams. In its simplest form, temperature topping works as follows. Exhaust gas temperature readings tell the turbine’s control system whether the gas turbine needs to be hotter or cooler, for a given operational requirement. That reading then is compared to the fuel flow set point and that set point raised or lowered, as required.

Other systems essential to the gas turbine’s operation but not covered in this summary, include:
• Compressor wash system (on-line and / or offline)
• Engine Condition Monitoring System which incorporates subsystems such as Vibration Analysis, Pulsation Monitoring, and Life Cycle Assessment.
• Fuel treatment (see case study in Design Development section)

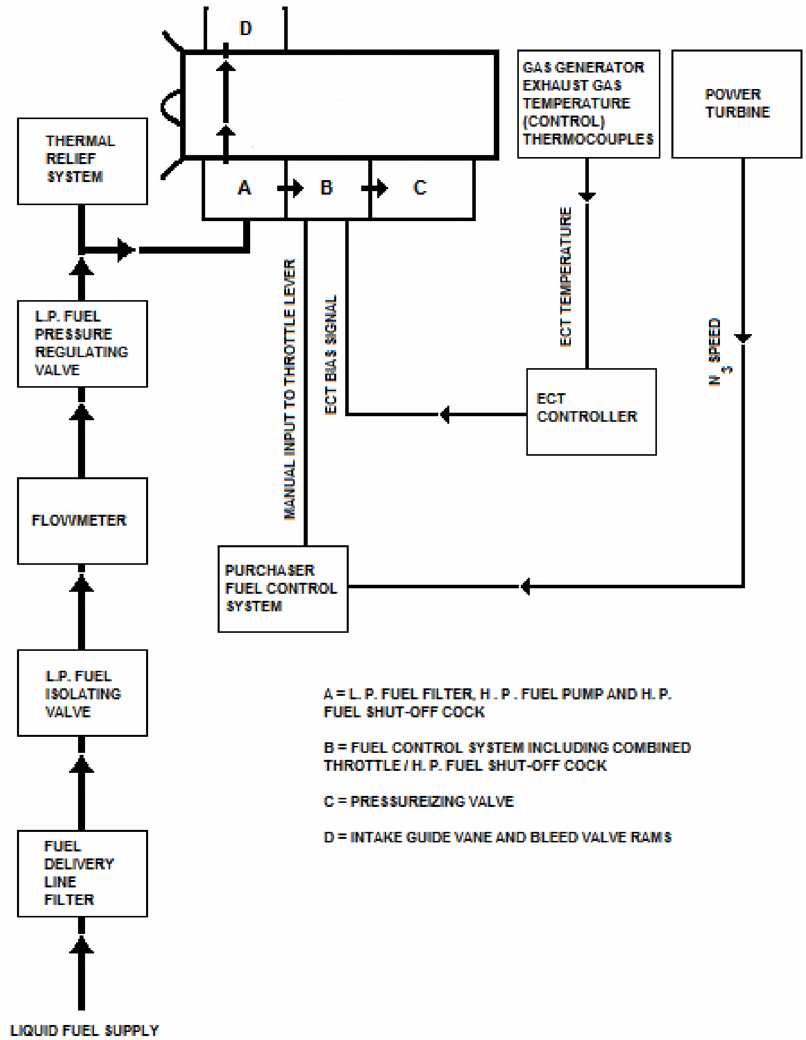


Fig. 41. Liquid fuelled phase 1 gas generator schematic. Source: Courtesy of Butterworth Heinemann, from “Process Plant Machinery” 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

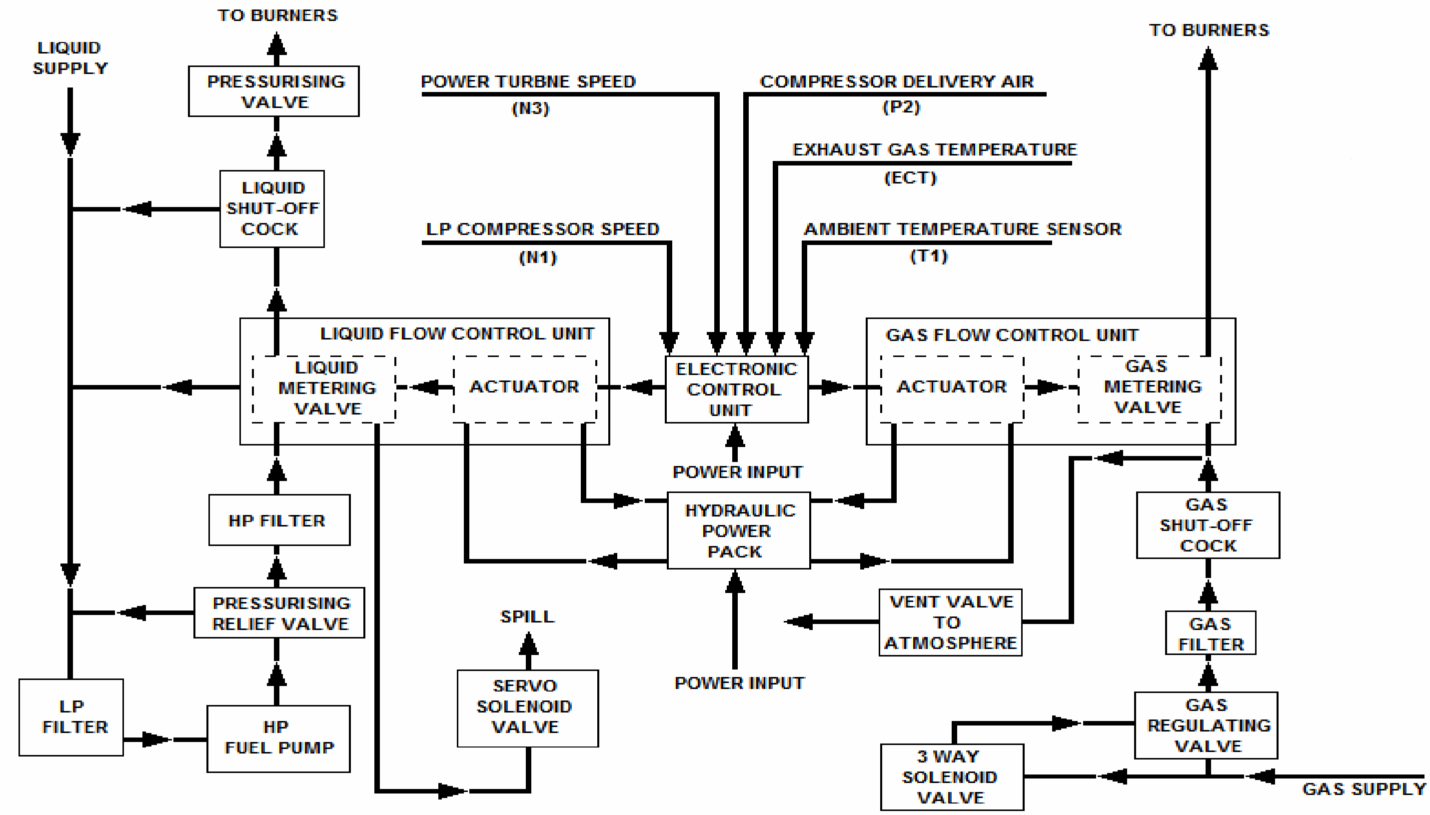
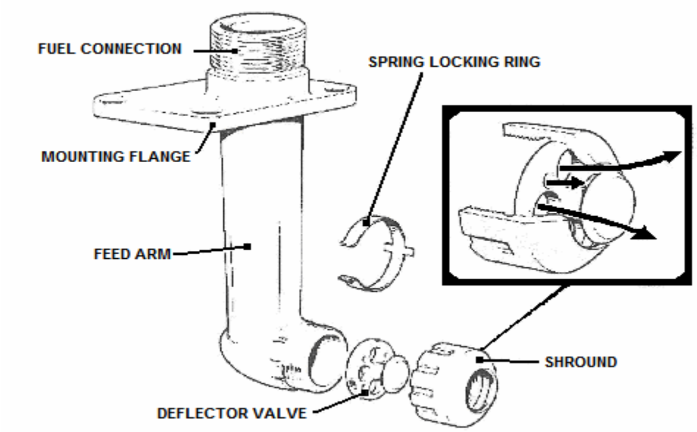


Fig. 42. Dual fuelled gas generator schematic. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce



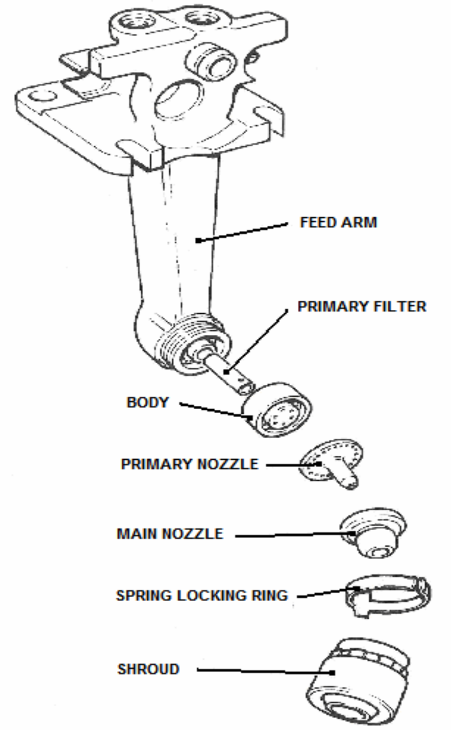


Fig. 43. Gas fuel burner. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

Fig. 44. Liquid fuel burner. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

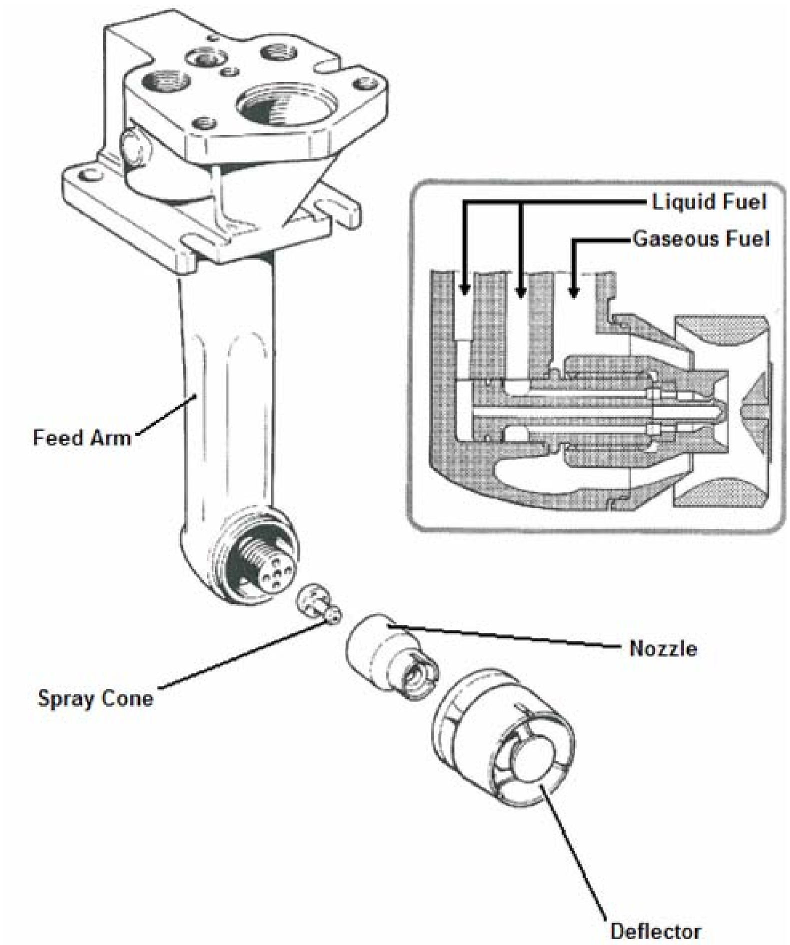


Fig. 45. Dual fuel burner. Source: Courtesy of Butterworth Heinemann, from "Process Plant Machinery" 2nd edition, Bloch, H. and Soares, C., 1998, original source Rolls Royce

Design Development with Gas Turbines[1,2]

This section deals with some of the predominant trends in gas turbine and gas turbine system projects and design development.

Maximizing Rotor Component Commonality

The field of gas turbine technology increases in sophistication daily. Every manufacturer has a unique design philosophy. Primarily, design development work concentrates on improving the core of already established designs. The market entry of a totally new gas turbine model with a substantially different core, represents a major capital investment and is usually only done if there is a substantial gap in that original equipment manufacturer's (OEM's) product line that the specific OEM intends to cover (See Figure 46 below. >>. Even then, an OEM takes this step only if potential revenues from the new turbine justify the development funds.

[1] "Gas Turbines: An applications handbook for land, air and sea", Soares, C. publisher Butterworth Heinemann.
[2] Notes from the annual panel session "Engine Condition Monitoring used to extend the life of gas turbine engine components", 1995 through 2003, Chair: Soares, C.

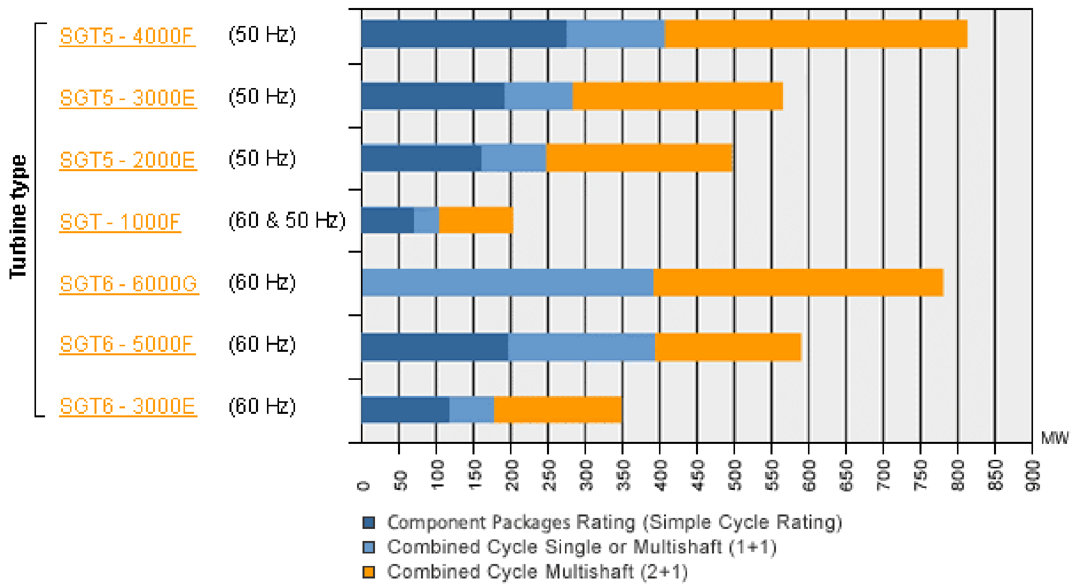
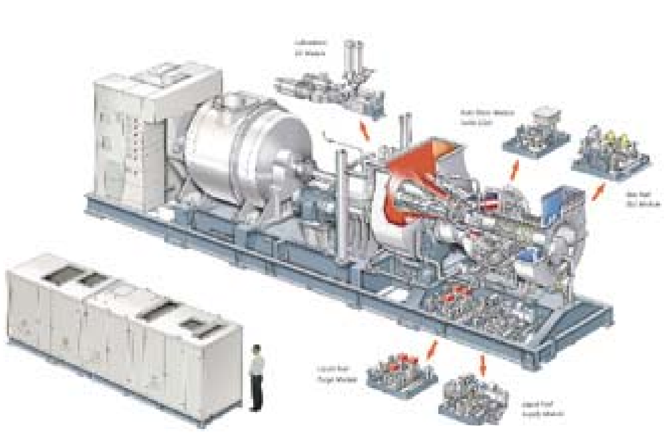


Fig. 46. Siemens gas turbine power plants range from 65 MW to 814 MW (simple cycle and combined cycle. Power output according to applied turbine and plant type. (Source: Siemens Westinghouse)

Several gas turbines have dual frequency capability. A dual frequency power generation package is illustrated in Figure 47.



Siemens' SGT-200 Industrial Gas Turbine for Power Generation (ISO) 6.75MW (e) Power Generation Package is of light modular construction, 50Hz or 60Hz, and suitable for small power generation, especially in locations where power to weight ratio is important (offshore applications) and small footprint is required. The SGT-200 is available as a factory assembled packaged power plant for utility and industrial power generation applications. It incorporates the gas turbine, gearbox, generator and all systems mounted on a base. The package is available for either multi-point or three-point mounting for onshore or offshore use as required. An option for acoustic treatment reduces noise levels to 80dB (A) and is available in carbon steel and stainless steel. Doors and panels are incorporated to provide access for servicing.

Fig. 47. SGT-200 Modular Package - Generator Set.
(Source: Siemens Westinghouse)

The cases below include an illustration of a similar rotor [Mitsubishi Heavy Industries, MHI][5], shape using different metallurgy, aerodynamic (including bleed air modifications) or cooling techniques to increase the power developed by that rotor. To increase compressor discharge pressure (and therefore mass of compressor air delivered and in turn power developed by the turbine), additional compressor stages can be added to give higher compression ratios. This can be done while leaving the core diameter the same.

Note 5: See footnote on page 38

The After-Sales Market

Generally, much of an OEM's revenue is made from the sale of new or reconditioned spare parts. End users exert pressure on OEMs to optimize component designs and thus reduce their operational cost per fired hour.

Therefore, design development that perfects component design within economically practical limits and develops repairability strategies, is continual. Design development also aims at offering a larger power range with models that have essentially the same core

geometry. This is done by optimizing metallurgical selections and improving cooling. The design development process is best illustrated by case studies (see below) drawn from OEM authored papers.
OEM strategy with respect to repair development varies, sometimes even within their own divisions. Factors such as end-user group pressure (to develop specific repairs), international economics (end users do not always pay the same rate in dollars per fired hour for "power by the hour" contracts) and other reasons unrelated to the gas turbine system itself.

So when OEMs merge or acquire divisions of another OEM, this may prove very beneficial to the end user, if certain technology areas improve. It may also prove a logistical problem with spare parts stocking and changing codes, if the "new" OEM also changes model numbers.

Acquisitions and Different Design Philosophies

OEM strategy with respect to repair development varies, sometimes even within that OEM's own divisions. Factors such as end-user group pressure (to develop specific repairs), international economics (end users do not always pay the same rate in dollars per fired hour for "power by the hour" contracts) and other reasons unrelated to the gas turbine system itself.

So when OEMs merge or acquire divisions of another OEM, this may prove very beneficial to the end user, if certain technology areas improve. It may also prove a logistical issue with spare parts stocking and changing codes, if the "new" OEM also changes model numbers.

Other facts that affect design development are the continuous acquisitions that occur among gas turbine manufacturers. Totally different design philosophies merge when this happens. Consider for instance Siemens' acquisition of Westinghouse. The latter's newest models at the time had strong evidence of design methods that originated with Mitsubishi (MHI) design methods, because of the technology cooperation they had previously had with Westinghouse. Later Siemens acquired a subsidiary of what was Alstom Power (formerly ABB) in Sweden. ABB's Swedish developed turbines had designs that had been independently developed in Sweden and were not always a scaled version of ABB's Switzerland designs, although they drew on specialized knowledge that had been developed in Switzerland. At one point ABB Alstom (before the "ABB" was dropped from the name) had acquired what was European Gas Turbines (EGT) which formerly was Ruston, an English manufacturer. Joint ventures from component suppliers' previous programs tend to add to the technology pool at an OEM's disposal.

Following an acquisition in 2003, the original EGT models, and the former ABB Stal (Sweden) models, are now part of Siemens. Siemens has renamed all of their turbines, including turbines that she had originated, such as the V series (V94.3, V64.3, V84.3 and so forth).

End users can benefit if they watch corporate evolution of this nature as it may extend, or reduce, their own constant drive to reduce their costs per fired hour.

Fleet size can also impose design development requirements. The larger OEMs, such as General Electric, tend to have several licensees that assemble their gas turbines. Designs that specify assembly methods which promote uniformity in terms of how a gas turbine is assembled save money, but may have to evolve with experience. At times, as with the introduction of the GE Frame 9F in the mid 1990s, a new design can prove vulnerable to inconsistencies in quality control systems between licensees. The 9F fleet went through a period of severe vibration suffered, on an inconsistent basis, by certain members of the fleet; some units were relatively free of this problem. Changes in rotor assembly methodology removed the potential for the compressor stack to be inaccurately assembled.

As personnel migrate between countries and different OEMs, design variations tend to follow. The wide chord fan blade was pioneered by Rolls Royce and featured on engines such as their Tay and the IAE joint venture V2500. Several years later, the GE 90 featured a wide chord fan blade, which is constructed and manufactured differently from the Rolls design, but shares its performance characteristics.

OEM methodology to solve the same issue may differ. For specific gas turbine plants sold in SE Asia in the early 1990s, both Siemens and Alstom, then ABB, used a silo combustor design. The Siemens design had several fuel nozzles, that had a fuel distribution pattern that reduced NOx levels to the level they had targeted. ABB chose to use a single fuel nozzle for essentially the same NOx level target as Siemens, but used water injection to reduce NOx levels. Later, to give their client base an option that would eliminate the need for boiler feed water quality for water injection; ABB developed a retrofit with multiple fuel nozzles.

As we will see in one of the case studies below, MHI (Mitsubishi) use a combination of air cooling, steam cooling open cycle and steam cooling closed cycle for their hottest airfoils. This then provides their customer base with a wide range of power developed values, all with essentially the same core geometry.

Metallurgy Limits TIT

The limiting factor to the maximum power to weight ratio a gas turbine can reach is the metallurgical tolerance of the alloys used in the hot section of the gas turbine. Ceramic coatings on the surfaces of the turbine airfoils can increase the peak temperatures these airfoils can tolerate, however ceramics have brittleness characteristics that have not been totally overcome yet. So the “ruling parameter” is turbine inlet temperature (TIT). TIT in turn is a function of the turbine flame/ firing temperature, compression ratio, mass flow, and centrifugal stress. So these factors limit size and ultimately, efficiency.

A rough rule of thumb is that 55°C (100°F) increase in firing temperature gives a 10 to 13 percent power output increase and a 2 to 4 percent efficiency increase. The combustion chambers and the turbine first stage stationary nozzles and blades are therefore the most critical areas of the turbine that determine its power output and efficiency.

Fuel Options

Fuel selection also plays a major part in determining cost per fired hour, depending on its physical state and purity level. Natural gas is the most desirable fuel, as it takes least toll of the gas turbine’s component surfaces. Diesel oil (distillate) is a liquid fuel and also takes minimal (if not quite as good as natural gas’) toll of the gas turbine components.

However, residual, also called “bunker” or crude oil is a viable fuel. Because of its high salt levels (sodium and potassium based), water washing is required. Also because of its Vanadium content, fuel treatment additives are required. The Vanadium salts that result take the Vanadium “out of solution” and the salts deposit on the surfaces of the turbine blades. The turbine can be washed, typically every 100 to 120 hours, and the salts are then removed. Were it not for the fuel treatment additives, the vanadium compounds that would form would form a hard coating on the turbine blades that could not be removed. For this entire system to work, TITs are kept down below 900 degrees Celsius. That TIT may be valid as base load and therefore part of a design or it may be run “derated” at the appropriate temperature until a “cleaner” fuel can be used.

Aeroderivative versus Industrial Gas Turbines

Industrial gas turbine compression ratios are in the order of 16:1 and aeroderivative (like their aeroengine parents) have compression ratios of about 30:1 and higher. About 50 percent of the total turbine power in any gas turbine is used to drive the compressor. Aero (and therefore aeroderivative) gas turbine designs have weight and size limitations depending on their mission profile. The minimized weight feature makes aeroderivatives highly suitable for offshore platform use, both in power generation and mechanical drive applications. Efficiency translates into fuel burn and this is a major and increasingly pertinent selling point. Rival OEMs in a specific engine size category vie for even 0.5% efficiency margin over their rivals. Design features that ultimately affect operator safety such as cooling air mass, are trimmed to the extent possible. Design engineers have been known to fight their management to get the pilots who fly their engines more cooling air, at the cost of efficiency. In severe service, such as aerobatic combat, that small margin of cooling air, can make the difference between the pilot getting home or not, especially if his engine is already severely stressed. War time conditions can and has included factors such as much heavier fuel than the aeroengines were designed for, being used. Such was the case with part of the Pegasus fleet (that power the VSTOL Harrier) during the Falklands war. In that particular case, the fleet survived the heavier fuel well, despite the fact that its TIT was higher than the industrial and marine engines that typically use the heavier fuel.

Industrial gas turbines have none of the weight limitations imposed on their aero counterparts. Like the LM2500, General Electric’s (GE’s) 40 MW LM6000 is an aeroderivative based on GE’s CF6-80C2. The LM6000 has 40 percent simple-cycle efficiency and weighs 6 tons. If we consider GE’s Frame 9F, we note an output of about 200 MW with a weight of 400 tons. The contrast in power delivered to mass weight ratios between the aeroderivative and the industrial model is evident. Further the 9F is only about 34 percent efficient.

High thermal efficiency (over 40 % on simple cycle and over 60 % on combined cycle are now common values for most new gas turbine systems) contributes to minimizing fuel burn and therefore minimizing environmental emissions. Even if an engine is “officially” an industrial engine, aero technology is likely to, at some point, contributed to its design. For instance, a contributor to V84.3 (Siemens Westinghouse) efficiency is the 15 stage compressor and 3 stage turbine which use aeroengine technology to optimize circumferential blade velocities. The turbine aeroengine technology is partially courtesy of Ansaldo, Italy (who contract manufacture turbine sections for Siemens Westinghouse) and therefore from Pratt and Whitney, on whose design technology some elements of Ansaldo's turbine manufacture are modeled.

With a land based turbine, the designer does not have to aim for maximum pressure rise across a stage together with weight minimization (or maximum power per pound of turbine). The priority in this case is maximum efficiency.

Repowering

Repowering is a growing trend in Europe and the US. The incentives include adherence to Kyoto objectives. Although emissions taxes are not yet reality worldwide, they are in some European countries. The higher efficiencies available with gas turbine options are another incentive, as they make IPPs far more competitive. A case in point is the Peterhead station in Scotland. The 2 boiler, 2 GE 115 MW Frame 9E station had been designed to operate on heavy fuel oil, LNG, sour gas, and natural gas. In 1998, the decision was made to increase plant capacity with three Siemens V94.3 combined cycle units. The V94.3 is a scaled up version of the V84.3 which can run at both 60 and 50 cycles. The economics of the situation are heavily influenced by the UK's gas supplies. Thus that station's efficiency went from 38% to between 50 and 55%. NOx emissions will be reduced by 85 %.

Another major reason for repowering is that what was thought to be 60 years worth of natural gas left in global supply terms was "updated" to 70 years plus recently. Evidence from ongoing exploration indicates that this figure will climb. Despite China's anxiety to use its coal, and the Middle East's desire to use its residual oil, the trend towards gas turbines burning cleaner fuels will continue as lending agencies increasingly tie their loans up with environmental standards as conditions. However, as gas turbines get better at burning pulverized coal dust, residual fuel and other erosive or corrosive fuels, use of the gas turbine will increase.

Environmental Factors

Legislation pressure on environmental emissions has created extensions on OEMs design staff to lower gas turbine emissions, particularly oxides of nitrogen or NO_x (See Table 4.). NO_x production will tend to increase with higher flame temperatures. NO_x control techniques include a variety of techniques, such as adding cooling air, or extending the combustion process with a two stage combustor (see Alstom's sequential burner design in the case studies), which results in lowered overall maximum combustor temperatures. Unburned hydrocarbons, particularly carbon monoxide or CO, are undesirable. Greenhouse gases, such as carbon dioxide and methane, are also the subject of increasing attention, as they contribute to global warming.

NO_x emissions (like oxides of sulphur or SO_x emissions) are now taxed in a growing number of global locations and carbon dioxide (CO_2) tax will soon be widespread. So the design development cases that follow include work on low NO_x combustor development and CO_2 sequestering projects.

Table 4. Emissions Factors for Utility and Industrial Combustion Systems [3]
(based on fuel energy input rather than output, i.e. not taking account of combustion efficiency)

Emissions Source	Emissions Factors (g/GJ energy input)				
	CO_2	CO	CH_4	NO_2	N_2O
Utility Application					
Natural gas boilers	56,100	19	0.1	267	n/a
Gas turbine, combined cycle	56,100	32	6.1	187	n/a
Gas turbine, simple cycle	56,100	32	5.9	188	n/a
Residual oil boilers	77,350	15	0/7	201	n/a
Distillate oil boilers	74,050	15	0.03	68	n/a
Municipal solid waste (mass feed)	n/a	98	n/a	140	n/a
Coal, spreader stoker	94,600	121	0.7	326	0.8
Coal, fluidized bed	94,600	n/a	0.6	255	n/a
Coal, pulverized	94,600	14	0.6	857	0.8
Coal, tangentially fired	94,600	14	0.6	330	0.8
Coal, pulverized, wall fired	94,600	14	0.6	461	0.8
Wood-fired boilers	26,260	1,473	18	112	n/a
Industrial Applications					
Coal-fired boilers	94,600	93	2.4	329	n/a
Residual-fired boilers	77,350	15	2.9	161	n/a
Natural gas-fired boilers	56,100	17	1.4	67	n/a
Wood-fired boilers	26,260	1,504	15	115	n/a
Bagasse/agricultural waste boilers	n/a	1,706	n/a	88	n/a
Municipal solid waste, mass burn	n/a	96	n/a	140	n/a
Municipal solid waste, small modular	n/a	19	n/a	139	n/a

Figure 48 is another example of a gas turbine and its primary operational data in simple cycle mode. Note NOx ppm value.

Fig 48. Alstom's GT13E2 (operating data below
is for simple cycle) Gas Turbine (Source: Alstom)

[3] Figures quoted in "Greenhouse Gas Abatement Investment Project Monitoring and Evaluation Guidelines" World Bank, Global Environment Coordination Division, Early Release Version, June 1994.

GT13E2

Fuel	Natural gas
Frequency	50 Hz
Gross Electrical output	172.2 MW
Gross Electrical efficiency	36.4%
Gross Heat rate	9376 Btu/kWh
Turbine speed	3000 rpm
Compressor pressure ratio	15.4 :1
Exhaust gas flow	537 kg/s
Exhaust gas temperature	522 °C
NOx emissions (corr.to 15% O2, dry)	< 25 vppm

The following cases are typical of, but cannot fully represent, the end results of contemporary OEM design development projects. The author's handbook covers several dozen, and they cannot all be condensed or repeated here. These cases feature some OEM methods of maximizing operational convenience and efficiency, while staying within legislative environmental guidelines. They also demonstrate how end-user requirements may shape the course of design development and can moderate an OEM's focus.

Case 1. Gas turbine system features that allow the use of residual oil as a fuel. [4]

Case 2. MHI steam cooling design for their highest temperature zones. The steam circuit can be either a closed or an open system type. In the latter case, the steam is released into the gas path of the products of combustion after it has completed its cooling task. [5]

Case 3. The use of low BTU "waste liquid" fuel. This case involved what was originally designated Alstom's GT-10 gas turbine model at the Petrochemical Corporation of Singapore (PCS) plant, Singapore. Highly pertinent to the operation was the use of a "stepper" valve in the fuel system supply. [6]

Case 4. Cycle modifications, involving water injection for power augmentation, to boost gas turbine performance. [7]

Case 1: Gas turbine system features that allow the use of residual oil as a fuel.[4]

Mixed fields (that produce both gas and oil) often want to use their oil as fuel. These mixed fields are common in many areas of the world including the offshore fields in Malaysia and the North Sea in Europe. The answer for some owners, who have a grade of oil that is better than residual oil, is to use that as fuel for reciprocating engines that burn crude oil for pipeline mechanical drives. The penalty for using this fuel in gas turbine power generation however, must be carefully weighed for the individual model in question.

With or without special design features, gas turbines designed for a (high grade) liquid fuel burn capability, can burn any liquid fuel with a consequential penalty in parts life. It can be done for emergencies as NATO studies for contingency measures in wartime conditions proved. However, gas turbines with oil fuel as an option (to gas), are increasingly popular in many areas of the world. If they can burn residual fuel, they are still more popular. The world, China included, can cheaply import the Middle East's glut of residual oil.

Light oil: There are some gas turbines that can run on light oil with very little penalty in performance versus natural gas. Consider the following data on what was the Alstom GT10, which burns both gas and oil.

[4] The author's Power Generation course notes, extracts from the author's articles for Asian Electricity and Modern Power Systems and extracts from her book "Environmental Technology and Economics", (publisher Butterworth Heinemann), on the installation of Alstom (formerly ABB) 13-Ds at the Shunde power plant in Guangdong province, China. Note that the 13-D application range is now fulfilled by their 11N-2 model, primarily a 60Hz model, which also serves the 50Hz market with inclusion of a gear box

[5] "Cooling steam application in industrial gas turbines and field experience", Kallianpur V., et al, Mitsubishi Power Systems

[6] Author's notes, Power Generation Systems course and author's articles in European Power News, Middle East Electricity and Independent Power Generation magazines

[7] The power of water in gas turbines: "Alstom's experience with inlet air cooling", Lecheler S., et al (Alstom power)

In British units:

	Light oil	Natural gas
Power (hp)	31,641	33,022
Thermal efficiency	33.1	34.2
Heat rate (BTU/hp-hr)	7,685	7,440
Exhaust gas temperature (degrees Fahrenheit)	998	993

In Metric units:

	Light oil	Natural gas
Power (MW)	23,100	24,630
Thermal efficiency	As above	
Heat rate (kJ/KW-hr)	10,880	10,518
Exhaust gas temperature (degrees Centigrade)	537	534

This option of running on oil versus natural gas is also available for newer, more sophisticated gas turbine models, such as Alstom's 13E2 which powers several SE Asian plant locations.

The choice of using oil as a gas turbine fuel is normally decided on the answers to three questions:

i) What will the efficiency penalty be?
ii) What will the TBO (time between overhauls) and parts longevity penalties be?
iii) Which fuel is inexpensively and abundantly available?

The answer to ii) is probably the more critical one to operators in terms of their cost per fired hour figures. Some OEMs (original engine manufacturers) therefore have a separate design to minimize the impact on ii) if the answer to iii) is "residual oil" (no. 4 or no. 6 oil).

China has an in-country steam turbine manufacturer, with coal reserves that outweigh its oil or gas resources, so gas turbine (or combined cycle, CC) territory within China is hard won. A CC operation powered by residual fuel is a design and operations achievement, due to hot section and fuel additive technology required. The ideal turbine for this application is a relatively low temperature, sturdy, preferably cast, simple design that then results in minimal maintenance. What was the 50Hz Alstom GT13D (and their 60Hz 11N2, which, with a gearbox, can replace the 13D) has a proven track record in these applications where far greater turbine sophistication with respect to alloys and turbine inlet temperatures would be self-defeating. These machines' track record thus far indicates that operations have been satisfactory to the owners and could indicate further such inroads into a difficult market. China needs to run on as cheap a fuel as possible with maximum efficiency and time between overhauls.

Production economics dictated that the -11N2 replace the -13D. They were very similar: the -11N2 package was adapted, so it could be substituted for the earlier model. The -11N2 can run on 50Hz or 60 Hz, produces about 109 MW at base load, and can handle the same dismal fuel quality as the -13D. The observations made in this case involve the Shunde power plant in Guangdong province China which uses Alstom residual fuel technology in its 13D2s.

The GT13D gas turbine operates under the critical firing temperature of 1015 degrees C (Celsius) without much derating. Each turbine develops about 90MW. 18 compressor stages and 5 turbine stages are lightly loaded, at a 43.6% gross combined cycle (LHV) efficiency, for longer time between overhauls. (The -11N2 was previously equipped only for 60 Hz generation. With an optional gearbox, it can also run at 50 Hz, and the -13D was phased out of production)

Residual oil as a fuel is not possible without specialized gas turbine design features. Corrosion, plugging and fouling will occur. Higher firing temperatures in most contemporary high performance gas turbines require complex blade cooling, expensive super alloys and substantial derating. The -13D has integrally cast blade and vane cooling passages, with relatively simple geometry (versus a high performance aerofoil which normally has laser produced cooling passages) and a large flow cross section. This provides better resistance against plugging.

Cooling air is extracted after the last compression stage, at the blade root. The air is routed to the first stage turbine blades below the rotor surface. The single piece welded rotor supported by two bearings is a simple, less vibration prone design. No through bolts are used: another useful maintenance feature. This design has only one silo combustor, a solid cast design. It has one large bore fuel nozzle, which helps avoid clogging and erosion. No air atomization is required, which means no compression air stream is required. The nature of the burner design means that water injection is required. At Shunde, water injection is 1.3 times the fuel flow rate (maximum 10.5litres/s). Water injection adds 9 to 10MW of power. No flow divider is required in this design, so no consequential temperature unbalance is observed. This also helps cut down on maintenance costs.

The generator is driven from the cold end, which means turbine exhaust end inspections are easier. All bearings are accessible without disassembly and no elbow conduits are required. As the generator is air cooled, no hydrogen system or hazards have to be allowed for. The cooling loop is closed and maintenance free. The boiler, a vertical assisted circulation, single pressure design type, has a preheating loop. It delivers 44kg/s of 37.5 bar steam at 475 degrees C. Sodium phosphate (Na_2SO_4) is used for anticorrosion measures in steam treatment.

Although the primary focus for this case is gas turbine system design modifications, these gas turbines are part of a combined cycle operation. (The steam turbine is a single cylinder design with a single flow low pressure section. Its gross output is 92MW. The steam turbine at Shunde runs with 472 degree C steam (480 degrees maximum) at 36 bars. The exhaust is condensed. Total gross power output then is 280 MW nominal. At Shunde 273 MW is guaranteed. The gross efficiency (LHV) at Shunde is 43% (43.8% nominal), based on a guaranteed heat rate of 8376 kJ/kWh (8221 nominal). Slow roll to running speed with the gas turbine takes 5 minutes. Getting the steam turbine running takes approximately two hours).

Combustion and fuel economics are as follows. Sodium (Na), Sulfur (S), and Vanadium (V) content in the fuel are the major problems. Na is removed by mixing preheated fuel with water and demulsifier and then centrifuging. Potassium (K) impurities are removed in the same manner and at the same time as the sodium down to 0.5 ppm total (for both the Na and K). The sulphur left in the fuel becomes SO_x upon combustion. The 120 meter stack at Shunde provides dispersal for the SO_x. In areas where legislated SO_x limits are tighter, flue gas desulphurisation or other methods can be used.

Magnesium additives combine with the vanadium to form salts that deposit onto the blade surfaces. When the turbine is shut down, the salt levels fall off with the drop in temperature. Remaining salts are washed off with plain water. In Shunde, the wash is done every 100 operating hours for heavy oil. If gas or diesel fuel (back up fuel) is used, no wash is required.

For inspection of the hot gas path, the inspector visually inspects the tiles on the inside of the combustor, the transition piece, and the first stage vanes. He uses a mirror to check the first stage blades. The other turbine and compressor stages can be observed by borescope. For major inspections every 16 to 24,000 hours, the burner is lifted off in one piece.

The limit for magnesium addition is 1105 degrees C, as at 1120 degrees C, MgO (magnesium oxide) solidifies to the extent it can only be chiseled off, and V_2O_5 (vanadium oxide) with its low melting point corrodes. (Both MgO and V_2O_5 are formed from the safe additive compound after 1120 degrees C). The turbine inlet temperature of the Shunde units is maintained at 990 degrees C.

When starting the gas turbines, diesel fuel is used until synchronous speed and then heavy fuel is used. This helps prevent clogging. The turbines are run for 5 minutes on diesel when shutting down. Again this prevents clogged nozzles and ignition problems. The -11N2 can also handle the same rough fuel as the -13D. Peak metal temperatures, internal metallurgy and fuel treatment requirements are all quite similar. The single burner design for this model can get NO_x down to 42 ppm with water injection. An EV silo combustor (several fuel nozzles) option is available if the end user has gas or diesel fuel. NOx can then be reduced to 15 ppm when at base load on natural gas.

A gas turbine inlet filtration system is also necessary in this location. This particular inlet filtration system has three stages. In the first stage the air flow direction is changed. The second stage consists of mats. The third stage is for fine filtration. The gas turbine compressors are still washed off-line every 300 to 400 operating hours.

Cheap fuel more than offsets the capital expenditure required for fuel treatment and additives, washing the fuel and other costs. This cost savings increases with the power capacity of a plant. Using a difference in residual oil and diesel prices of $50 per ton, a 300 MW facility similar in design to Shunde's could save $22 million at 0.5 capacity factor and $36 million at 0.75 capacity factor. Savings of $264 million and $432 million respectively are indicted over the life of the plant, (US dollar figure expressed at 1995 values).

Case 2: MHI steam cooling design for their highest temperature zones.[5]

The art of steam cooling has proved a valuable asset in the drive to maximize power per unit weight in gas turbine technology. The current limiting factor to maximum horsepower for a given rotor size is turbine inlet temperature (TIT). Internal cooling to the gas turbine vanes and blades, as well as the combustion liner, keeps those airfoils cooler for a given fuel flow rate. The steam cooling circuit can be either a "closed" or an "open" design. In the latter, the steam coolant is allowed to enter the gas path, which provides a further horsepower boost to the gas turbine.

The major manufacturers compete with design modifications like steam cooling to produce effective turbines in the various horsepower size categories, "effective" in this context meaning that the turbine in question delivers its rated horsepower (and other deliverables) without leaks or other operational problems. Table 7a shows -D, -F, -G and –H category gas turbine parameters for the Mitsubishi Heavy Industries (MHI) range of gas turbines. These parameters vary for different manufacturers, but the table nevertheless provides an illustration of the effectiveness of steam cooling in raising TITs. For illustrative purposes, this article references parameters with MHI gas turbines. Readers may use this as a template for queries on or comparisons with other manufacturers' designs.

Note also that Table 5 mentions subcategories of the major horsepower size categories. These occur due to individual customer requirements or conditions that "create" a subcategory that can then be offered to other clients. For instance, the G1 is an upgraded G, with cooling steam applied to the blade ring in addition to the combustion liners.

Table 5. Categories of gas turbines for the Mitsubishi Gas Turbine product line [5]

GT type	TIT	Cooling Type		Performance (ISO: LHV)				NOx
	deg C	Turbine	Combustor	Gas turbine		Combined Cycle		ppm
M501DA	1250	Air	Air	114MW	34.9%	167MW	51.4%	9
M501F	1350	Air	Air	153MW	35.3%	229MW	52.8%	25
M501F3	1400	Air	Air	185MW	37.0%	285MW	57.1%	9
M501G	1500	Air	Steam	254MW	38.7%	371MW	58.0%	25
M501G1	1500	Air	Steam	267MW	39.1%	399MW	58.4%	15
M501H	1500	Steam	Steam	-	-	403MW	60.0%	15

Steam cooling, like any other cooling technology helps alleviate the potential life cycle cost incurred with partial load cycling operation and frequent starts and stops.

As of March 2004, MHI had 150,000 operating hours of steam cooling experience with their G units, logged. This figure includes both 50Hz and 60Hz applications. Both their G and H models have steam cooled combustion liners. The H model also has blades and vanes in the first two rows of its turbine rotor and the blade rings, steam cooled.

Material selection

With steam cooling, as with any design feature, wear limits and future repairability are major concerns. The steam cooling feature merits concern about corrosion rate and electrochemical reaction strength levels, which would depend on the mating materials in question and the steam purity. Although many steam cooling designers would like to claim that the steam supply conditions are no more stringent than the steam required for their steam turbines, higher steam quality standards make good economic sense at the design conditions in G and H gas turbines.

Stress corrosion cracking is accelerated by long term steam exposure, particularly at high stress concentration locations like disc dovetails, bolt holes and spigots. MHI were able to use the same low alloy steel as for their F design with their G and H models which gave them a wealth of data. Further, they used scaled up but similar geometry for the hotter models. With respect to scale size after steam exposure, the actual engine tests confirmed earlier laboratory prognoses closely. See Figure 49.

In MHI's design, expensive aircraft engine type alloys such as Inconel (for the rotors) and single crystal castings (for blades and vanes) are avoided. This enhances reliability, initial capital costs and life cycle costs.

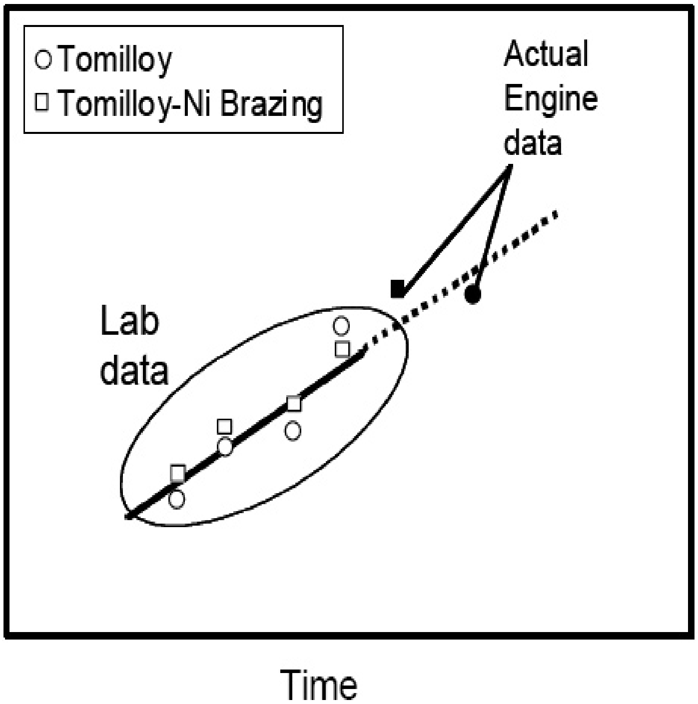


Fig. 49. Scale size after steam exposure [5]

Operation at load

With the H model, steam is delivered at about 5 Mpa (megapascals). Maximum steam temperature can reach around 600 degrees C. Load testing in 1999 revealed a leakage point at 60 percent load. A redesigned connector got the model up to full load conditions with no leaks.

Active Clearance Controls (ACC)

The term ACC was originally coined around aircraft engine design where the cooling medium was air. In this land based application, MHI supply the steam cooling stream to the blade rings for better blade tip clearance at different load conditions. Originally developed for the H model, this feature has also been added to the G model as an upgrade.

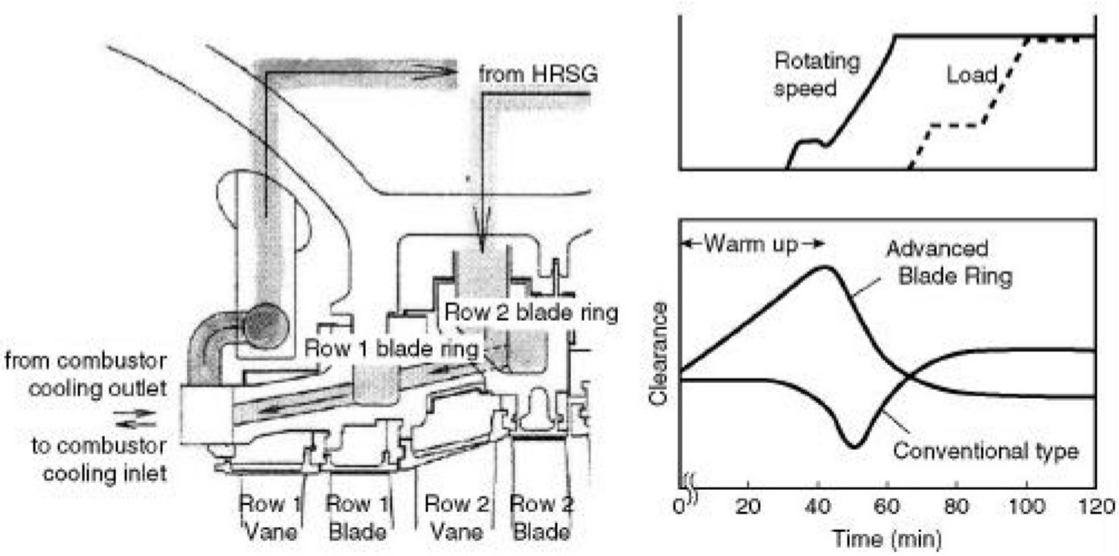


Fig. 50. Blade tip Active Clearance Control [5]

Closed loop reliability

Steam flow is monitored continuously. Three main monitored parameters are linked to the control system via a redundant interlock. See Figure 51.

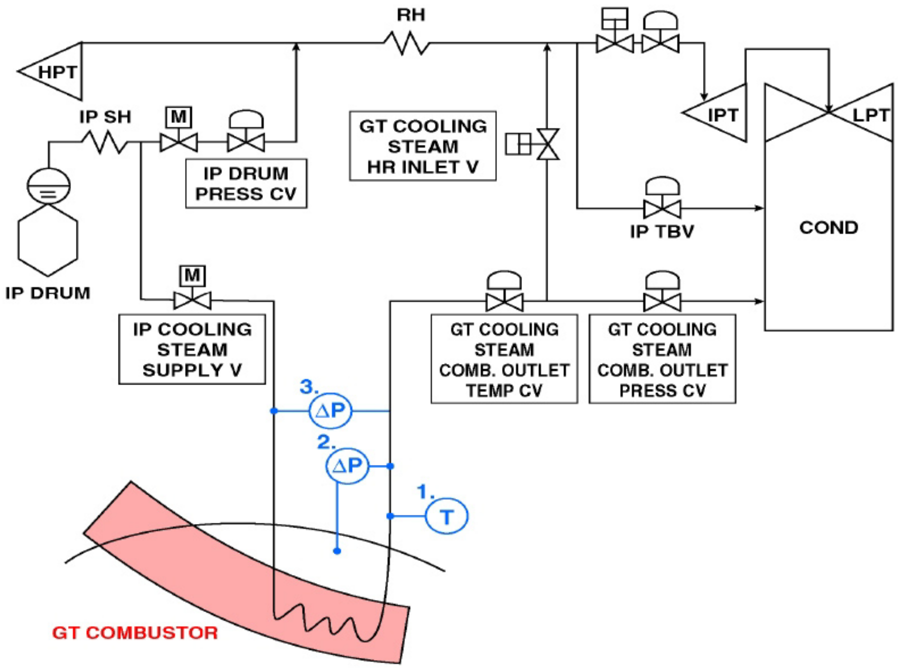


Fig. 51. Steam cooling continuous monitoring and interlock [5]

The interlock allows for both alarm and shut down functions depending on the parameter readings. The three main parameters are (with reference to Figure 51):

1. Cooling steam temperature at the combustion liner outlet, which gives an indication of steam overheating (interlock: alarm and runback).
2. The control system keeps the steam cooling pressure at higher than the combustor shell pressure, so low differential between these two parameters indicates steam leaks (interlock: alarm and trip).
3. Differential pressure across the liner can indicate inadequate steam flow (interlock: alarm and trip).

Blade path temperature (BPT) spread monitoring provides a back-up indicator to this system and helps pinpoint where a combustion liner, for instance, may have an integrity problem, such as a crack. There are redundant steam supply strainers with continuous monitoring of the differential pressure across them, to check of obstruction of the steam cooling passages with solid carry over from the heat recovery steam generator (HRSG) or auxiliary boiler. On shutdown, an air purge sequence eliminates the potential for condensate accumulation in the steam cooling circuit.

Combustion liner design

To allow for steam passage and for better heat transfer properties, the combustion liner design is a double walled structure. Flame temperatures for the F, G and H turbines is the same, however with the G and H designs, the combustor exit temperature is higher. See Figure 52. There is no cooling air mixing with the cooling steam design.

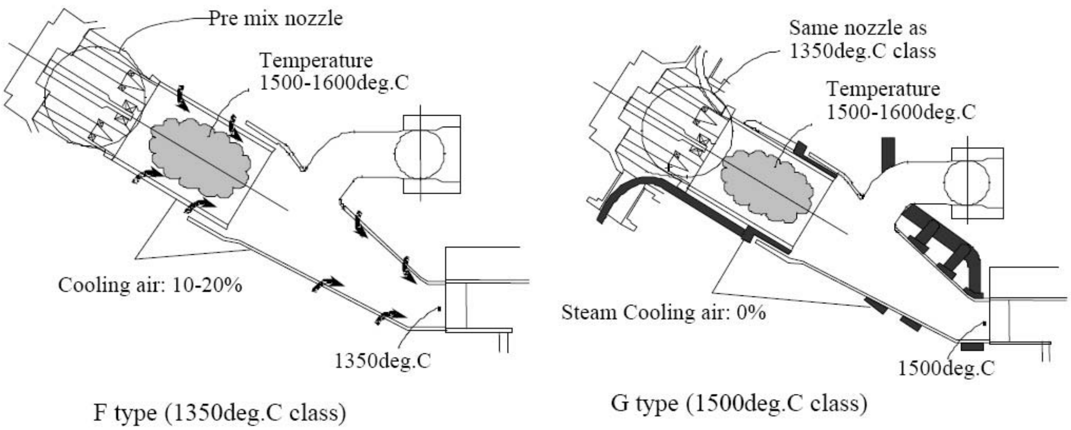


Fig. 52. Schematic of an F and G combustor. [5]

To date, there has been no delamination experienced with the G model liners. All 18 (as of March 2004) G models operate with varying external temperature conditions, fuel type and other variables. Figure 53 shows the condition of a combustor liner at the combustor interval inspection. The TBC (thermal barrier coating) is intact. Protective monitoring systems have proved effective in ensuring the steam reliability and flow characteristics for the closed-loop cooling-steam.

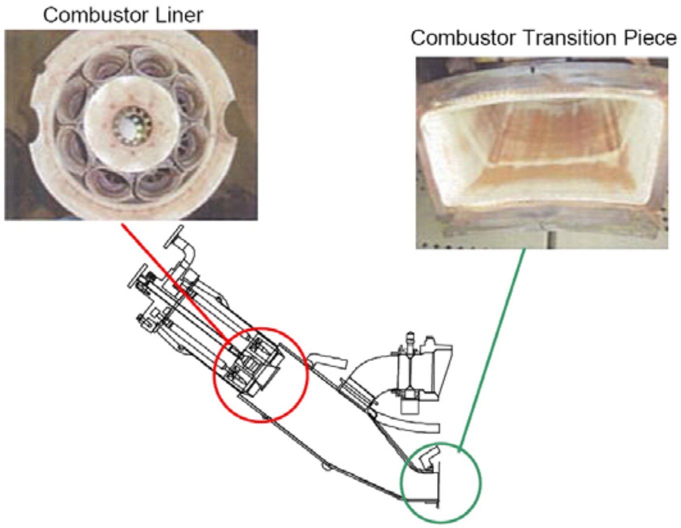


Fig. 53. Condition of the Operated Combustor Liner. [5]

Application case for a steam cooled G model

MHI's 501G model was installed in combined cycle (CC) application at Korean Electric Power Corporation's (KEPCO's) Ilijan's power plant in the Philippines. There are 2, 600 MW blocks, each with two gas turbines and a steam turbine. Performance test results indicated 57.8 percent efficiency (natural gas), at a net rated capacity of 1285.7MW.

At Ilijan, an auxiliary boiler is used to supply the combustor cooling of the first gas turbine unit. The gas turbine is started, run up to synchronization speed and loaded to 50MW. At this speed, the cooling steam supply is switched to the intermediate pressure (IP) superheater (normal combustor steam cooling supply).

All water requirements for this plant are met with sea water using reverse osmosis desalination. Water quality needs to be with in required parameters for steam to be admitted to the steam turbine, which happens between 50 and 100MW load. When the first gas turbine is in combined cycle operation, the second gas turbine can be started, again using IP steam for combustor cooling. The second gas turbine is synchronized at 100MW. Loading on the train continues at 11MW/minute up to full rating.

Case 3: The use of low BTU "waste liquid" fuel.[6]

Deregulation is now a major feature in the power production industry's development. The incentive for "small" power users, such as process and petrochemical plants, to produce their own power (become small power producers or SPPs), increases. Thailand provides an excellent illustration of this. Thailand has difficulty producing all the power the country needs with just the efforts of their national power company. For several years now, she has allowed bids from large independent power producers (IPPs) to better match her power demand curve growth. What she has also done is provided incentives for process plants to produce their own power, and sell the excess back to the national grid. The amount that can be sold back is often limited by distribution line size, which is as small as 15 kV, in the case of the grid adjacent to Esso's Sriracha refinery for instance, but nevertheless the scheme is in place.

Most countries in SE Asia are "a work in progress" in terms of their power supply and tariff infrastructure. The Petrochemical Corporation of Singapore (PCS) decided to take advantage of "pool rules for small generators" which covered generators of less than 10 MW and industrial in-house generators ("auto-generators"), which were instituted in Singapore as of April 1, 1998.

An SPP such as PCS does not have the luxury of a known steady load for its power needs. Also, the quality, type and heating value of their fuels will vary. This is because they use process gases and fluids for fuel whenever they can, especially if that is the most cost effective use for what would otherwise be a waste process fluid. Due to the variations in the different characteristics of these fuels which are in essence different process streams, two things are required:

- A gas turbine design that will accommodate fuels with a wide range of heating values. Such a turbine generally also has a more conservative design with turbine inlet temperatures (TITs) that will not be the highest for that turbine's power range.
- A very fast response valve (for cut-off of the fuel supply) is required. Without such a valve the exhaust gas thermocouples on the gas turbine would note large swings in turbine exhaust temperature. The key to PCS's successful use of process fluids - which it didn't have much other use for - as fuel, is valve response time and actuation characteristics. An ideal valve for this type of application is a "stepper" valve or its equivalent.

The "stepper" valve and functional equivalents: The stepper valve is a fast response electrically operated valve which was pioneered by Vosper Thornycroft, UK (aka HSDE, UK) in the mid 1960's. The term "stepper" actually refers to the motor type that drives the valve as opposed to the valve itself. The motor is a stepper motor, as opposed to a torque or AC or DC motor. Its self-integrating function ensures that the valve will proceed to a desired position and then the motor will stop. With other motors, the motor has to continue to run in order to keep the valve in that position - such valves need signals to cue them: run, stop running, then start running again, and so forth. If something were to happen causing the valve to fail, the stepper-type valve position would still lock and the system would continue running. The valve then makes the system fault tolerant, which is critical in applications such as emergency power supply generators. It also provides the fast response required by aeroderivative and some industrial gas turbines. This is useful for both power generation and mechanical drive service. Before the stepper valve was introduced in the mid 1960s, hydraulic and pneumatic actuation valves were used to provide the required response time. This increased the overall complexity of the fuel system. As always with instances where system complexity is heightened, system cost rose, but mean time between failures (MTBF) and availability decreased.

The valve takes up very little space on the installation and service people unused to this new design spend frustrated time looking for the extensive "old" equivalent control system.

Development of valves that could compete with HSDE's original stepper arose from competition with that early design. As a result, there are now many manufacturers who produce functional equivalents on the market, for use in gas turbine fuel systems, high resolution controls for robots, automatic machining controls and so forth. In PCS's application, they use a Moog (German manufacturer) valve which uses a DC motor. To get the same "stay in position" feature as a stepper type valve would have, manufacturers typically use a spring to hold a position.

Design aims of fast response valves: The original design aims of the stepper type valve generally include the following safety considerations:

• A fail freeze or fail closed option, depending on whether the operator is a power generation facility ("freezing" at the last power setting is then required) or a pipeline (in which case turbine shut down on valve failure is required).
• The liquid fuel version of the valve incorporates a pressure relief valve protecting the system against over pressure and the fuel pump running on empty or "deadheading", caused by closure of valves downstream of the fuel valve during system operation.

• High speed response of less than 60 ms required by aeroderivative gas turbines to prevent overspeed in block off-load conditions.
• Explosion proof actuation to appropriate specification standards, allows operation in hazardous methane service.
• Resistance to fuel contaminants including tar, shale, water, sand and so forth.
• 24 volts DC is the maximum drive voltage which ensures personnel safety
• Corrosion resistance in components exposed to wet fuel and corrosion resistance to all parts if the service is sour gas.

Other operational objectives that dictate design features are operator's requirements for:

• Low mean time to repair (LMTR). The target of 1 hour, achieved with modular design, together with the target MTBF provided an availability of 99.998% for HSDE's original stepper.
• Higher Mean time between failures (MTBF). In HSDE's case, a target of 50,000 hours was set and achieved.
• Low maintenance costs, since the modular design can be repaired by an individual with relatively low expertise. Service intervals are 12 months.
• Large control ratio which allows control over the ignition to full load as well as full speed ranges to be possible with one fuel valve. Fuel pressure variation compensation is provided. The additional speed ratio type control valve found in many other industrial gas fuelled installations is not required here.
• Low power consumption since an electric motor of less than 100 watts is used. This also eliminates the need for additional hydraulic or pneumatic systems. Also black starting is more reliable if the fuel system is powered by the same batteries as the controller.

PCS applications experience with fast response valves: Power production in Phase II of the Petroleum Corporation of Singapore or PCS, was commissioned in June 1997. PCS is part of a massive petrochemical plastics conglomerate in Singapore. Power production was an afterthought, as when they were built, their design did not include provision for them becoming an SPP. PCS chose a nominally 25 MW (23 MW in their normal ambient conditions) ABB GT10, although their power needs are roughly 26MW. This was because while SP were pleased to sell them their residual requirement; they would not buy any power from SPPs at the time of original power plant design.

The turbine is fuelled by three different types of fuel, depending on the state of the plant. The BTU for each type varies, so again the fast response time for the stepper valve is critical.

As PCS operations found, their fast response valve proved as useful as the stepper valve has been for power generation on the North Sea oil and gas platforms. The fast response time of the Moog (and other stepper valve manufacturers') design helps the valve avoid the sudden burst of excess temperatures that accompany higher heating value fuel. (North Sea platform users frequently operate gas, liquid or gas & liquid fuel mixtures).

Not all gas turbines are tolerant of a wide range of fuel types in a single application. Some of them require a whole different fuel system - nozzles, lines and all components - to be able to handle a totally different heating value fuel. In this application in Singapore, the ABB machine shows no sign of distress, which is interesting since the heating value of the fuel types varies as much as 50 percent. The exact fuel composition data is proprietary to PCS.

PCS's GT10 heat recovery steam generator (HRSG) provides a reliable source of steam. The plant exports steam to the nearby Seraya Chemicals plant in addition to fulfilling their needs.

Emissions and steam supply: The original ABB EV burner design - a low NO_x burner which can be fitted and retrofitted on the GT10, fuel types permitting - was not fitted in this case. The EV burner will handle clean natural gas and clean diesel fuel. It was not suitable for the high hydrogen content and variations in fuel composition that this application involves. Such fuels need a more forgiving fuel system, as well as water or steam injection to keep the NO_x down. The PCS Singapore application uses steam for NO_x reduction purposes. The steam is piped in through nozzles that are adjacent to the fuel nozzles on the fuel manifold of the GT10's annular combustor.

The source of the steam is the heat recovery steam generator (HRSG) that is packaged as part of the GT-10 system. If and when required, the plant also can draw high pressure steam from their process cracker.

In PCS' case, one boiler has been found to suffice. This is noteworthy as in applications like this, a redundant "packaged boiler" (running hot and on minimum load) is often found essential. This is so that it is possible to pick up the steam load should the turbine trip or be unavailable due to maintenance. A common subject for debate is whether uninterrupted steam supply during the switch from HRSG mode to fresh air firing is possible without flame out on the boiler supplementary burners.

The PCS plant is part Japanese owned, so the specifications the installation had to meet matched those of environmentally particular Singapore, as well as the Japanese, who are the most environmentally strict practitioners in Asia. Steam injection reduces NO_x levels from 300 to 400 mg/MJ fuel to just below 100 mg/MJ fuel.

In this and similar cases, the GT system footprint may be of prime concern, if space comes at a high premium. The figure below outlines what the layout for the application (and similar applications) above may look like.

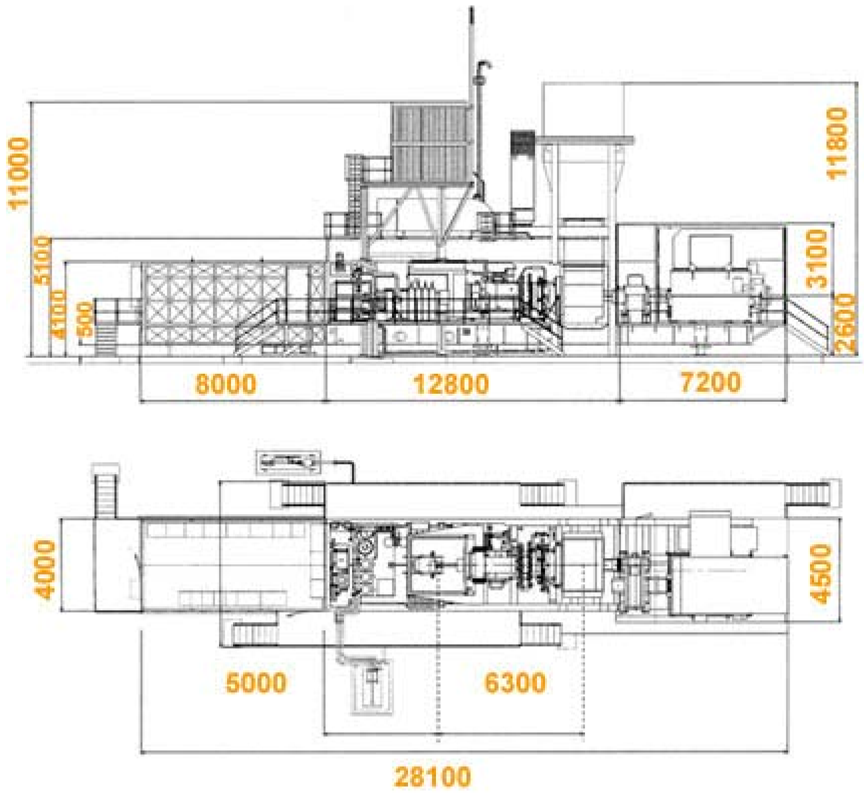


Fig. 54. SGT-600 Industrial Gas Turbine - 25 MW, Power Generation Application Layout (Note: Siemens SGT-600 was Alstom's, formerly ABB's GT-10) Dimensions in millimeters, mm (Source: Siemens Westinghouse)

In summary: The GT10's ability to use three different "waste" petrochemical fluids as fuel, despite the 50 % variance in these three fluids' heating value, is significant to process plants who could similarly become SPPs. Note that NO_x emissions stayed below legislated limits for countries such as environmentally strict Singapore.

Case 4. Water and/ or steam injection for power augmentation and NO_x reduction [7]

Gas turbines swallow air and therefore are sensitive to ambient temperature and pressure. To increase the power output of gas turbines, especially in hot, humid (air density decreases with rising temperature and humidity) climates, water injection is used. (See Figure 55). The location of injection is commonly the filter plane and the compressor inlet.

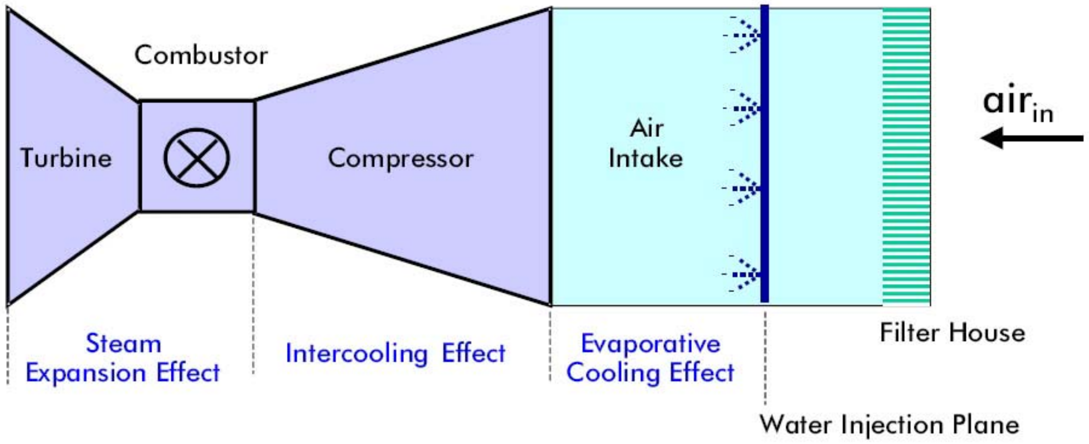


Fig. 55. Air Inlet Cooling Principle [7]

The power gain is achieved due to 3 factors:

i) The water which evaporates in the air intake increases relative humidity of the air from ambient conditions to nearly saturation. The evaporation of water reduces the air temperature hence density and the GT swallows a higher air mass flow. Higher power generation per unit volume of air swallowed and better efficiency result.
ii) The water which evaporates inside compressor reduces the compressor work and increases GT net power output and GT efficiency as well.
iii) The turbine power output is increased proportionally to the increased mass flow of air and water.

Maximum power gain is achieved, if water is added at 2 locations in the air intake: just after the fine filter and additionally near the compressor intake as shown in fig. 58. After the fine filter an evaporative cooler or a fogging nozzle rack saturates the air and near the compressor intake a high fogging nozzle rack injects additional water, which evaporates inside the compressor.

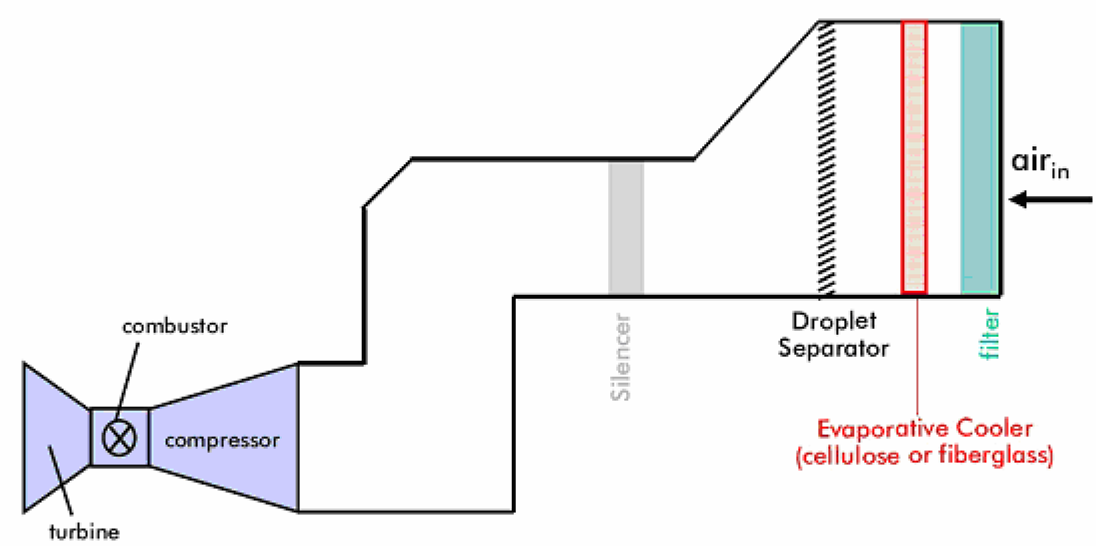


Fig. 56. Evaporative Cooler System [7]

Air chiller: An air intake chiller system consists of a heat exchanger, which is located in the air intake downstream of the filter. The heat exchanger cools the compressor inlet flow by the transfer of heat energy to a closed cooling water circuit. The closed cooling water is re-cooled in plate heat exchangers by one or more chillers. The closed loop cooling water is forwarded by one or more chilled water pumps. Load control regulates the cooling energy of each chiller to the desired plate heat exchanger outlet temperature of the cooling water. Outlet temperatures for each chiller correspond to a set point to the local control. The chillers are usually installed in the gas turbine air intake downstream of the air filter together with a droplet separator. The latter is needed to take out water droplets from condensation of humid air.

Evaporative coolers: Generally, they are installed in the gas turbine air intake downstream of the air filter together with a droplet separator (see Figure 56). The evaporative cooler increases humidity close to saturation. The amount of evaporated water depends on ambient temperature and humidity. The water evaporates mostly before entering the compressor and the air is cooled down before compressor inlet. Thus, the air mass flow through the gas turbine is increased, which increases the power output of the unit. The evaporative cooler is only switched on and off. The cooler media and the droplet separator produce a pressure drop between 1.5 to 3 mbar and need an axial extension of the filter-house (see Figure 57a).

The major components of an evaporative cooler are:
• the evaporative cooler media (cellulose or fiber-glass, see Fig. 57b)
• a water distribution manifold
• a water sump tank with a recycle pump
• a droplet separator (see Fig. 57c)

Water requirements

The water must be at least potable or flocculated and filtrated water quality or can be de-mineralized water. The water consumption is higher if tap water is used. Maximum total capacity is 25,000 l/h for a GT26 or GT13 and 17,000 l/h for a GT24 or GT11, where only 1 1,000 l/h and 7,500 l/h are evaporated and the remaining blow-down water is re-circulated.

Fig. 57. a) Evaporative Cooler Location, b) Evaporative Cooler, c) Droplet Separator [7]

Inlet fogging

Like evaporative coolers, this OEM’s fogging systems ALFog (an Alstom trademark) are typically installed in the gas turbine air intake downstream of the air filter (Fig.58).

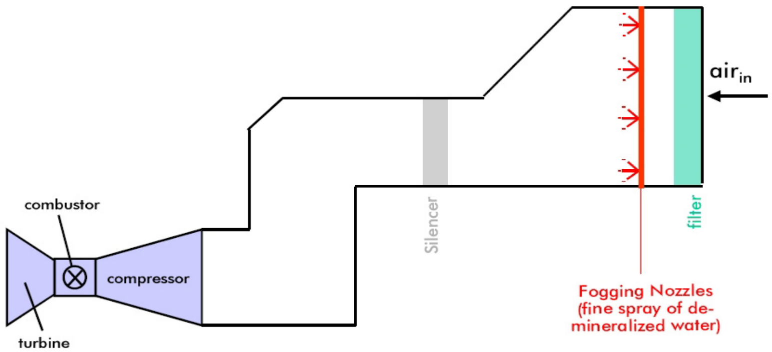


Fig. 58. Fogging System Arrangement [7]

The fogging system injects small water droplets into the air by nozzles to increase humidity close to saturation (90-95%). The amount of injected water depends on ambient temperature and humidity and is controlled by logic. The water evaporates and the air is cooled down before entering the compressor. In contrast to evaporative coolers, fogging systems have negligible pressure losses and do not need an axial extension of the filter house and are therefore ideal for retrofitting.

Fig. 59. a) Fogging Nozzle Rack, b) Fogging Pump Skid [7]

The major components of a fogging unit are:
• the nozzle rack with nozzles (fig. 59a)
• the pump skid including a control unit and a valve skid (fig. 59b)
• a water drain system for the air intake and the intake manifold.

The nozzles are mounted on tubes which are installed in the air intake downstream of the filter. Swirl nozzles are used in Alstom's fogging system (trade name ALFog). They provide the required droplet size. Small droplets promote good evaporation in the air intake, high power augmentation and low risk of erosion.

A high pressure piston pump feeds de-mineralized water at constant pressure (typically 140 bars) to the valve skid. The valves allow the sequencing of the water flow rate into sub-groups (typically 15 or 31, depending on design conditions). These subgroups are switched on and off by the control logic in order to adjust the water mass flow to ambient conditions. At lower ambient humidity and the higher ambient temperature, higher water quantities are needed to saturate the air, so more sub-groups are switched on.

Typically 3 additional drain lines are installed in the air intake before and after the silencer and in the manifold. This is to ensure that water films and large secondary droplets, which might be generated on obstacles inside the air flow, are extracted from the air-stream flow. Water must be de-mineralized and 2 standard fogging systems are used, one for a design ambient humidity of 45% (design capacity 8,000 l/h or 2.2 kg/s for GT26 or GT13) and one for a design ambient humidity of 30% (design capacity 12,000 l/h or 3.3 kg/s for a GT26 or GT 13).

High Fogging System: In order to increase power augmentation further, an additional nozzle rack is installed near the compressor intake. These systems are called high fogging, wet compression, over-spray or over-fogging systems. ALSTOM's high fogging system ALFog is installed horizontally in the gas turbine air intake (fig 60). The system sprays small water droplets (<50µm) through nozzles into the air. These droplets evaporate mainly inside the compressor as the air is heated up during compression.

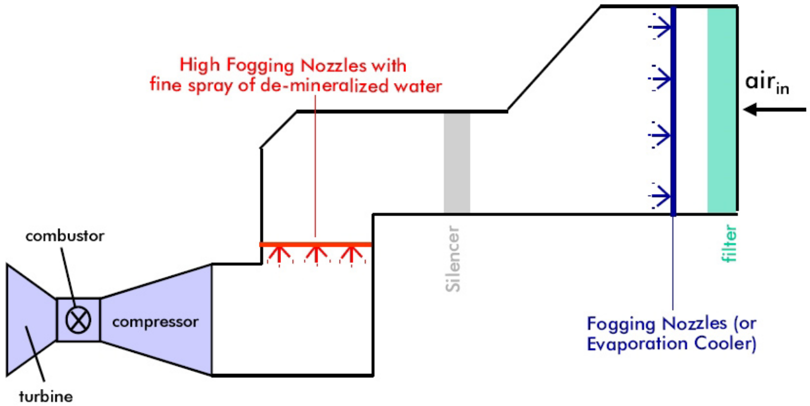


Fig. 60. High Fogging System in Combination with Fogging or Evap Cooler [7]

The power of the gas turbine is increased mainly by 2 effects:
• Compressor inter-cooling, which reduces compression work and compressor discharge temperature.
• The mass flow through the turbine is increased.

While fogging and evaporative cooler power increase depends on ambient conditions, the high fogging power increase is nearly independent of ambient humidity and temperature.

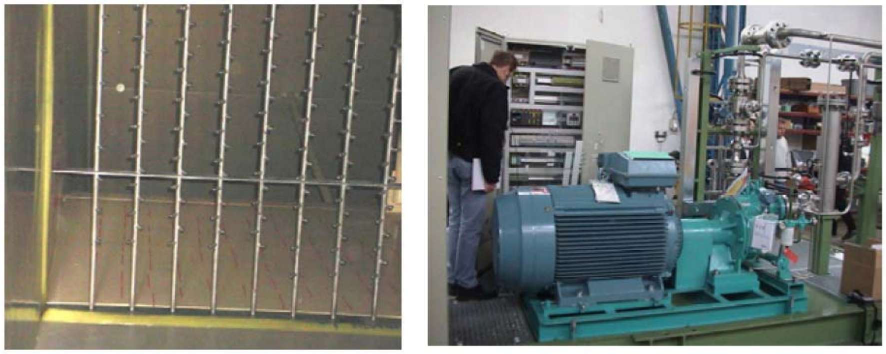


Fig. 61. a) High Fogging Nozzle Rack, b) High Fogging Pump Skid [7]

The major components of a high fogging unit are
• the nozzle rack with nozzles (fig. 61a)
• the pump skid including a control unit (fig. 61b) and a water filtration system
• the valve skid with staging valves
• a water drain system for intake manifold

Swirl nozzles are used in Alstom's high fogging system for the same reasons as with the regular fogging system. The high-pressure pump operation is also similar. The valves, located at the valve rack, allow the sequencing of the water flow rate into subgroups (typically 5 or 10), that are switched on according to the power demand. Drains in the air intake manifold ensure that water films and large secondary droplets are extracted from the air-steam flow.

The total water mass flow capacity of the high fogging system for a GT24 and GT26 is currently 1.2% of the air intake mass flow of the specific engine at ISO conditions. Accordingly, the demand of de-mineralized water is about 18,000 l/h or 5 kg/s for a GT24 and about 25,000 l/h or 7 kg/s for a GT26.

If the control system is not adjusted to take into account the effect of the water content due to high fogging the pulsation levels of the combustion system and CO emissions may increase. Steady state cycle simulations confirmed that high fogging leads to a slight shift in the hot gas temperature if dry TIT (turbine inlet temperature) formulas are applied without any adoption. As countermeasure a modified TIT formula analogue to those used for oil operation with NO_x water injection or operation with steam injection for power augmentation was implemented. This takes into account the amount of water injected for High Fogging. When using the adjusted TIT formulas high fogging has a negligible influence on CO emissions under base load operating conditions where the CO emissions are small (typically < 5 ppm). NO_x typically appears to decrease with increasing high fogging water mass flow.

Gas Turbine Performance

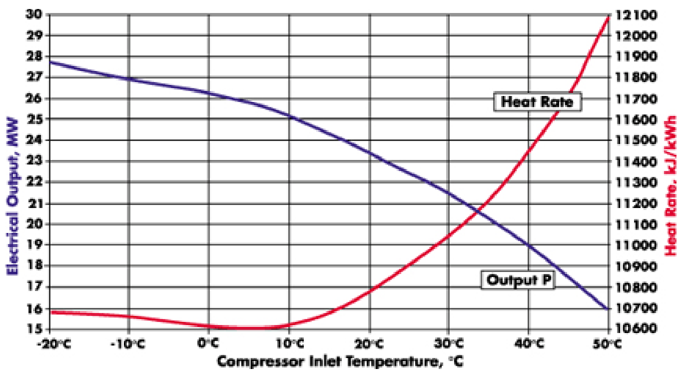
Ambient Condition Effects, Performance Optimization, and Extending Application Range

Certain atmospheric conditions have a critical impact on any given gas turbine's available power:

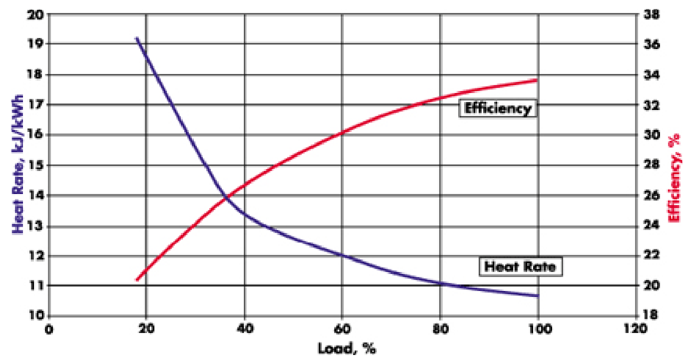
a) Ambient temperature: As this rises, a gas turbine may swallow the same volume of air, but that air will weigh less with increasing atmospheric temperature. Less air mass means less fuel mass is required to be ignited with that air and consequential lower power developed.
b) Altitude: Increasing altitude means lower density air, so that is turn decreases power developed by the turbine.
c) Humidity: Water vapor is less dense than air, so more water vapor in a given volume means less weight of that air than if it had less water vapor. The effect is the same as with the two above factors.

The figure below provides graphical representation of how external conditions can affect gas turbine performance. The following conditions apply to figures 62 (a) through (d):

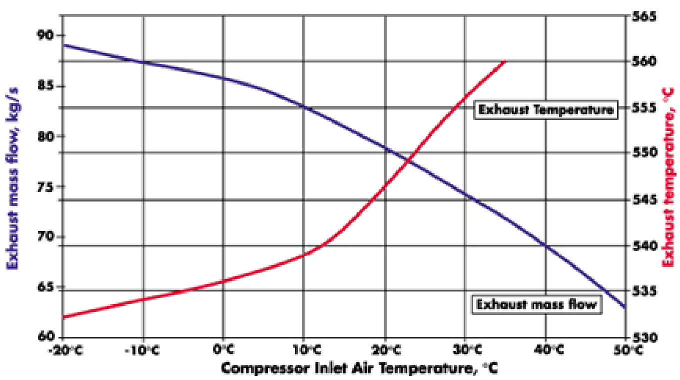
• intake losses 10 mbar / 4" H2O
• exhaust losses 25 mbar / 10" H2O
• relative humidity 60%
• altitude sea level



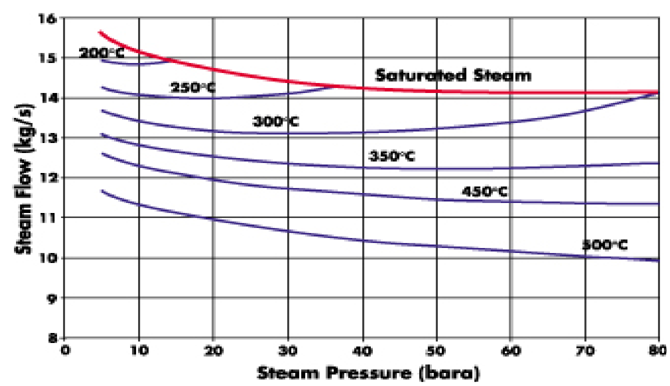
a) Generator output and heat rate versus compressor inlet air temperature



b) Heat rate and efficiency versus load



c) Exhaust gas flow and exhaust temperature versus compressor inlet air temperature



d) Nominal steam production (in combined cycle application) capability:

Fig. 62. Performance Data: SGT-600 Industrial Gas Turbine - 25 MW (Source: Siemens Westinghouse)

The subject of performance optimization is a vast one which would include several subtopics. Inlet cooling and water/ steam injection for power augmentation can be methods which are used to supplement power “lost” by factors such as high ambient temperatures, and high altitude. See the section on Design Development.

The table below on performance for the Siemens SGT6-5000F (formerly Siemens Westinghouse W501F Econopac) indicates the difference water injection and steam injection can make to nominal power ratings.

Table 6. Net Ref. Performance for the Siemens SGT6-5000F.

Combustor Type	DLN Dry	Conventional Water Injection	Conventional Steam Injection	DLN * Steam Augmentation
Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Net Power Output (kW)	186,500	196,900	205,400	204,420
Net Heat Rate (Btu/kWh) (LHV)	9,260	9,700	8,995	9,035
Net Heat Rate (kJ/kWh) (LHV)	9,770	10,233	9,490	9,532
Exhaust Temperature (°F/ °C)	1,087/586	1,063/573	1,090/588	1,090/588
Exhaust Flow (lb/hr)	3,848,400	3,963,600	3,981,600	3,971,324
Exhaust Flow (kg/hr)	1,745,634	1,797,889	1,806,054	1,801,393
Fuel Flow (lb/hr)	80,284	88,787	85,892	85,840
Fuel Flow (kg/hr)	36,417	40,274	38,961	38,897
Fuel	Liquid	Liquid	Liquid	Liquid*
Net Power Output (kW)	179,200	185,000	196,500	
Net Heat Rate (Btu/kWh) (LHV)	9,536	9,794	9,027	
Net Heat Rate (kJ/kWh) (LHV)	10,060	10,333	9,524	
Exhaust Temperature (°F/ °C)	1,050/566	1,037/558	1,062/572	
Exhaust Flow (lb/hr)	3,895,200	3,963,600	4,006,800	
Exhaust Flow (kg/hr)	1,766,863	1,797,889	1,817,484	
Fuel Flow (lb/hr)	91,940	98,709	96,143	
Fuel Flow (kg/hr)	41,704	44,548	43,610	

** Steam injected through the combustor section casing into the compressor discharge air to increase output.*
** Steam augmentation with liquid fuel available on a case-by-case basis.*

The following figures also demonstrate the effect of atmospheric conditions on the power developed, this time for a much larger turbine model than the SGT-600 depicted previously in this section.

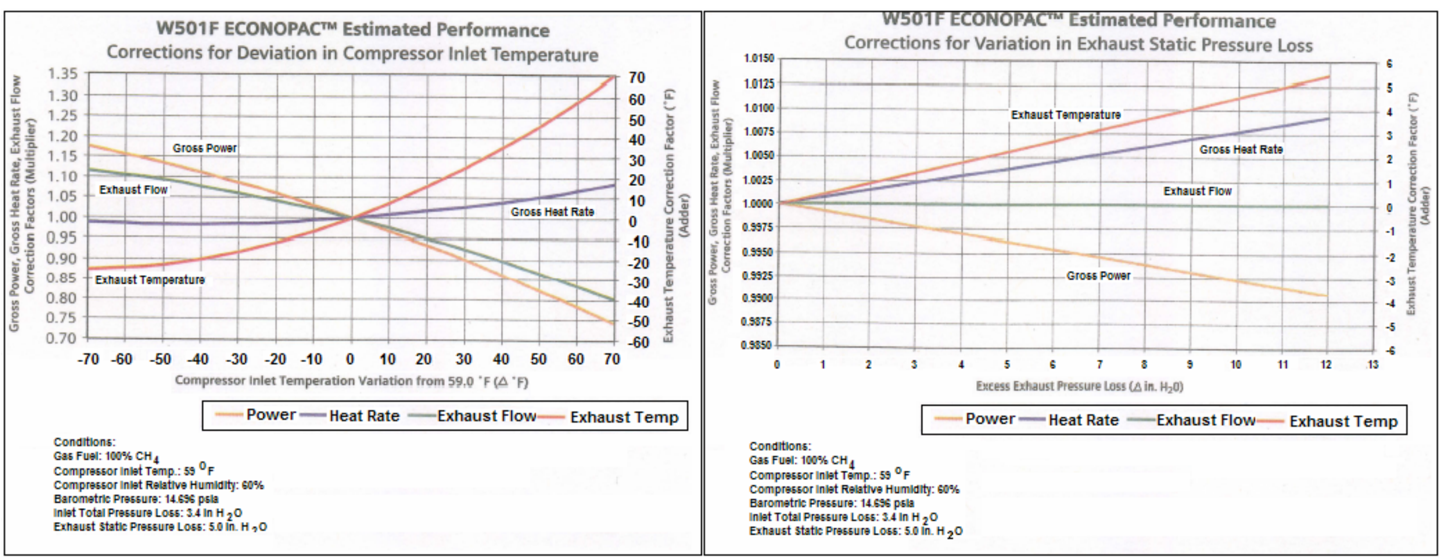


Fig. 63. SGT6-5000F (formerly the W501F) Estimated Performance (Source: Siemens Westinghouse)

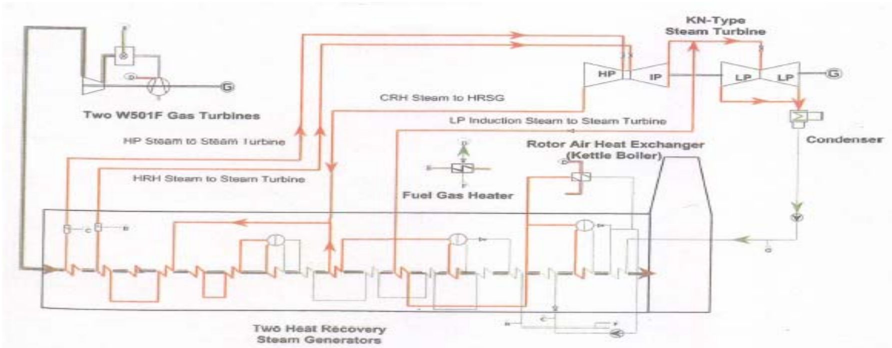
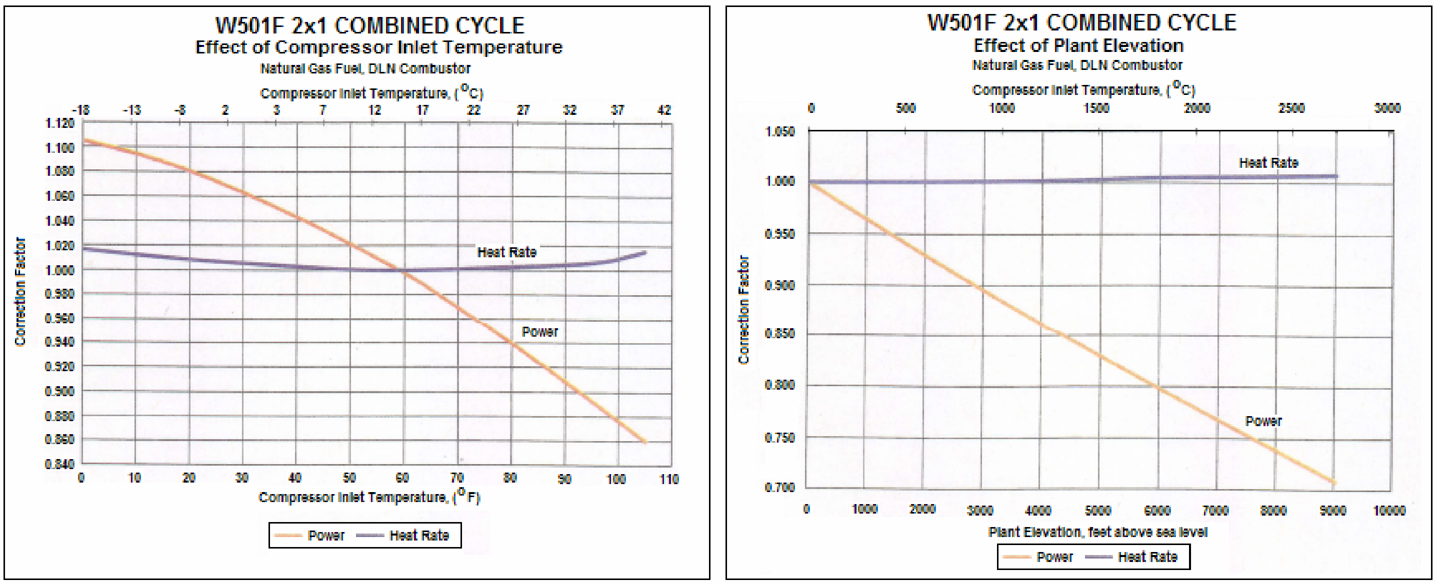


Fig. 64. Combined Cycle Diagram with Drum-Type Boiler Source: Siemens Westinghouse



Operating Conditions		
Supplemental firing	No	Yes
Ambient Temperature (o F / o C)	59/15	59/15
Relative Humidity (%)	60	60
Barometric Pressure (psia/bars)	14.69/1.033	14.69/1.033
Fuel	Natural Gas	Natural Gas
Fuel Heating Value (LHV)	20980 But/lbm	20980 But/lbm
Fuel Heating Value (LHV)	48800 kJ/kg	48800 kJ/kg
Fuel HHV/LHV Ratio	1.107	1.107
Generator Power Factor	0.9	0.9
ST Backpressure (in.-HgA/mbar	1.5/50	1.66/55
ST Throttle Pressure (psia/bars)	1817/125	2260/156
ST Throttle Temperature (o F / o C	1050/565	1050/565
ST Reheat Pressure (psia/bars)	351/24	437/30
ST Reheat Temperature (o F / o C)	1050/565	1050/565
Gross CT Output (MW)	369.8	369.8
Gross ST Output (MW)	206.4	244.8
Gross Plant Output (MW)	576.2	614.6
Net Plant Output (MW)	568.5	606.4
Net Plant Heat Rate (btu/kWh)	6060	6125
Net Plant Efficiency (%)	56.3	55.7

Fig. 65. SGT6-5000F (formerly the W501F) 2x1 Combined Cycle Source: Siemens Westinghouse

Depending on how one defined performance optimization, the term could include cycle modifications and support systems that are external to the gas turbine core. Some examples are:

- cycle modifications (which may also include, but are not limited to, inlet cooling systems, that are discussed under "Design Development")
- engine condition monitoring systems
- life cycle counters/ assessment

In the interests of space, these topics are not discussed here but they are exhaustively covered in the author's book on Gas Turbines.

As discussed in the section on design development, performance optimization is frequently attained by maximizing the power available using modifications to the base core. This allows the OEM to use proven technology that has long emerged from prototype growing pains, to fulfill a broader mandate in terms of power requirements and other operational needs. A case in point, Siemens' SGT-700 (29MW) is an uprated SGT-600 (24MW), which then fills a broader range of applications.

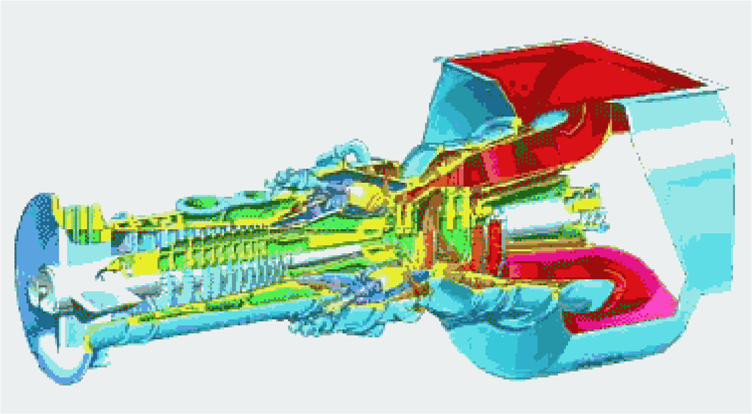


Fig. 66. SGT-700 Gas Turbine - 29MW
(Improved power output and efficiency over the SGT-600)
(Source: Siemens Westinghouse)

The SGT-700 has simple cycle shaft output of 29.1 MW and a thermal efficiency of 36% at base load on gas. This two-shaft machine can be used for both power generation and mechanical drive in both combined cycle and cogeneration applications. As a skid-mounted package with single-lift capacity and standard anti-corrosion materials and coatings, the SGT-700 is also suitable for offshore applications. The updated machine has full dry low-emission (DLE) capability. It can operate on both gas and liquid fuels with on-line switch-over between fuels. To optimize performance, the SGT-700 power turbine is equipped with advanced profile blades that improve gas flow. Its overall design ensures easy service access to the combustor and burners. The revised 11-stage compressor produces a higher pressure ratio and an increase in mass flow through the engine. This results in greater power output and higher efficiency. Direct drive of pipeline or process compressor is provided for by the free high-speed power turbine, eliminating the need for a gearbox. The digital control unit is based on the proven design of the SGT-600.

An application case for the SGT-700 illustrates an example of extending the application of a basic gas turbine core (in this case the SGT-600) design. We noted in the section on design development, and the Mitsubishi case study (see Case Study 2) which listed several variations on the same GT core that additional power was added with essentially the same gas turbine core, with the addition of design features (for instance steam cooling instead of air cooling in certain hot section areas). Frequently, these developments result from a customer's request: "I really could use another "x" MW in that plant, if you can make that happen" or "I'd rather have a slightly larger version of your "y" model rather than two of the "z" model, as I only have "w" amount of space and I can run the larger "y" at base load anyway, most of the time". This "core growth" design is really an extension of design development work, as any such design modification has to be full load tested. Some air or steam leaks may not show up at 60% load, but may appear at close to 100% load. So the OEM goes through the expense of rigorous testing to minimize the risk of warranty-period costs.

The application example below, which illustrates application of an SGT-700, is also another "repowering" (see the section on Combined Cycles) case illustration.

Fig. 67. Municipal utility in the southern Swedish town of Helsingborg (Source: Siemens Westinghouse)

The very first SGT-800 gas turbine was delivered to Helsingborg Energi AB (now called Öresunds Kraft). This municipal utility in the southern Swedish town of Helsingborg is using this gas turbine to extend its Vasthamn coal-fired power station. The SGT-800 gas turbine has been integrated with an existing steam turbine system to create a combined cycle, CHP plant. The project is supported by the State Energy Authority and DESS (the Delegation for Energy Supplies for Southern Sweden). The turbine was ordered in August 1998 and connected to the grid at 100% load in November 1999. It burns natural gas from the pipeline which passes through Helsingborg. Fitted with AEV burners, it provides emissions of NO_x and CO below 15 ppmv (at 15% O_2).The electrical generating capacity at Vasthamn went from 64 MW to 126 MW, and the heat production capacity from 132 MW to 186 MW.

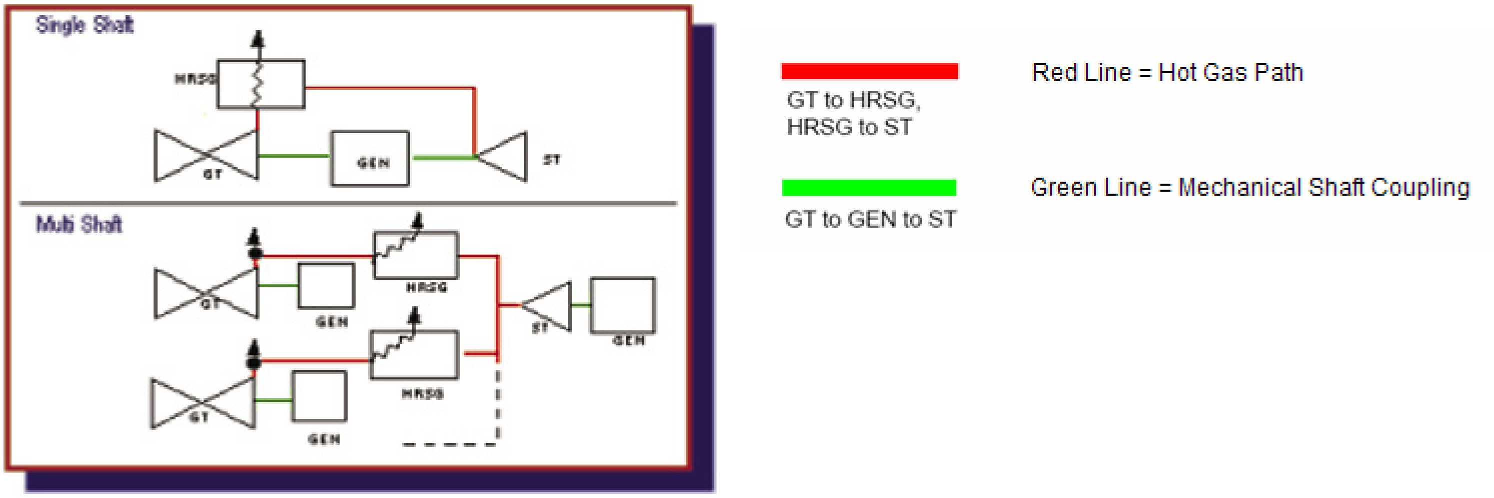
Combined Cycles

Combined Cycle Basic Components, Terminology and Heat Cycle(s)

The term combined cycle (CC) refers to a system that incorporates a gas turbine (GT), a steam turbine (ST), a heat recovery steam generator (HRSG), where the heat of the exhaust gases is used to produce steam and a generator. The shaft power from the gas turbine and that developed by the steam turbine both run the generator that produces electric power.

The term "cogeneration" means generation of both work (shaft power) and heat (steam, in the case of a CC). So a combined cycle is a form of cogeneration.

Fig. 68. Single and Multi shaft arrangements for CC plants (Reference: The World Bank)



The following figure shows a single shaft CC cycle block diagram in more detail.

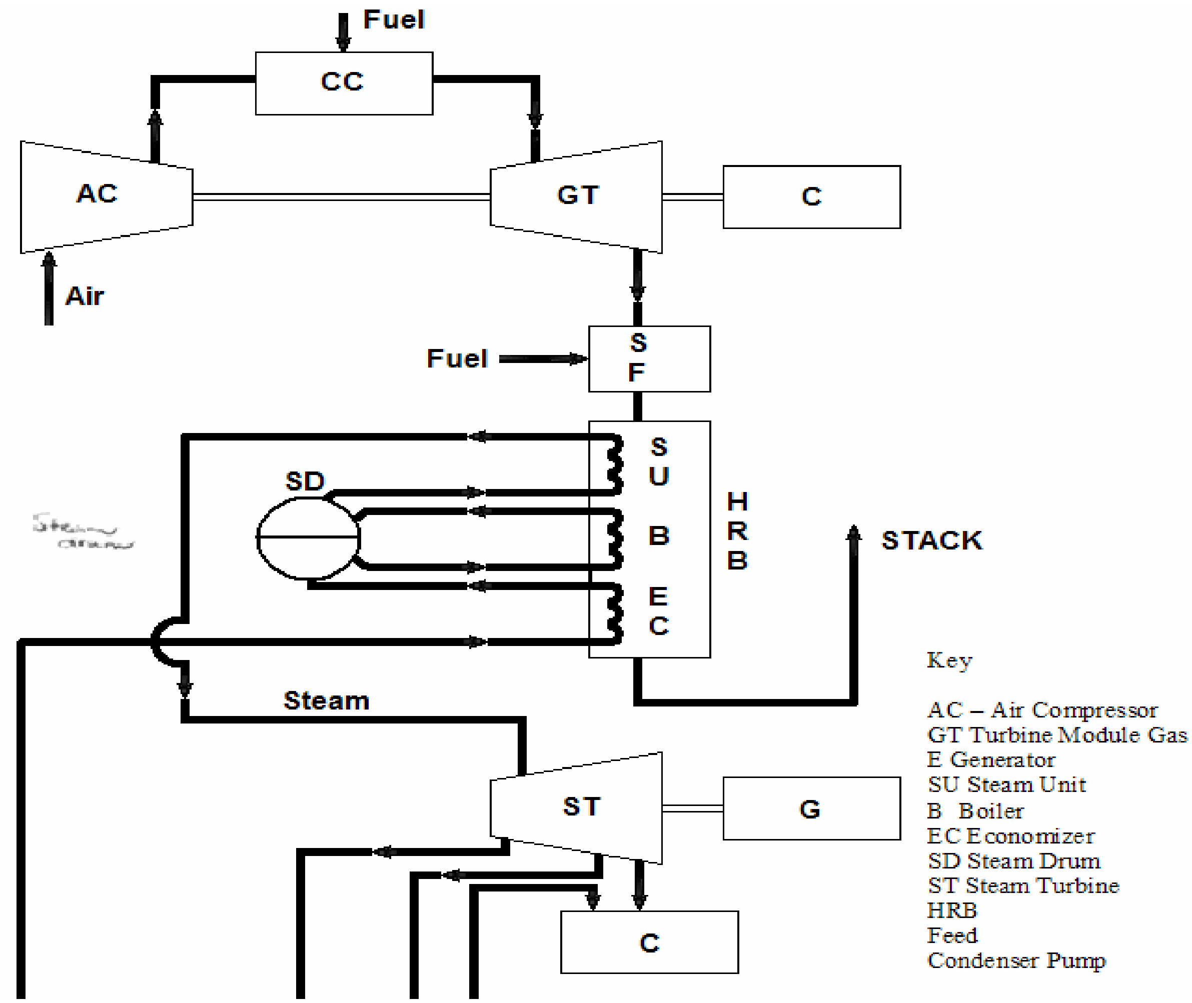


Fig. 69. A schematic diagram for a single shaft combined cycle.
Source: Courtesy McGraw Hill, from “Power Generation Handbook”, Kiameh, P.

The following figure shows a schematic for a dual pressure combined cycle.

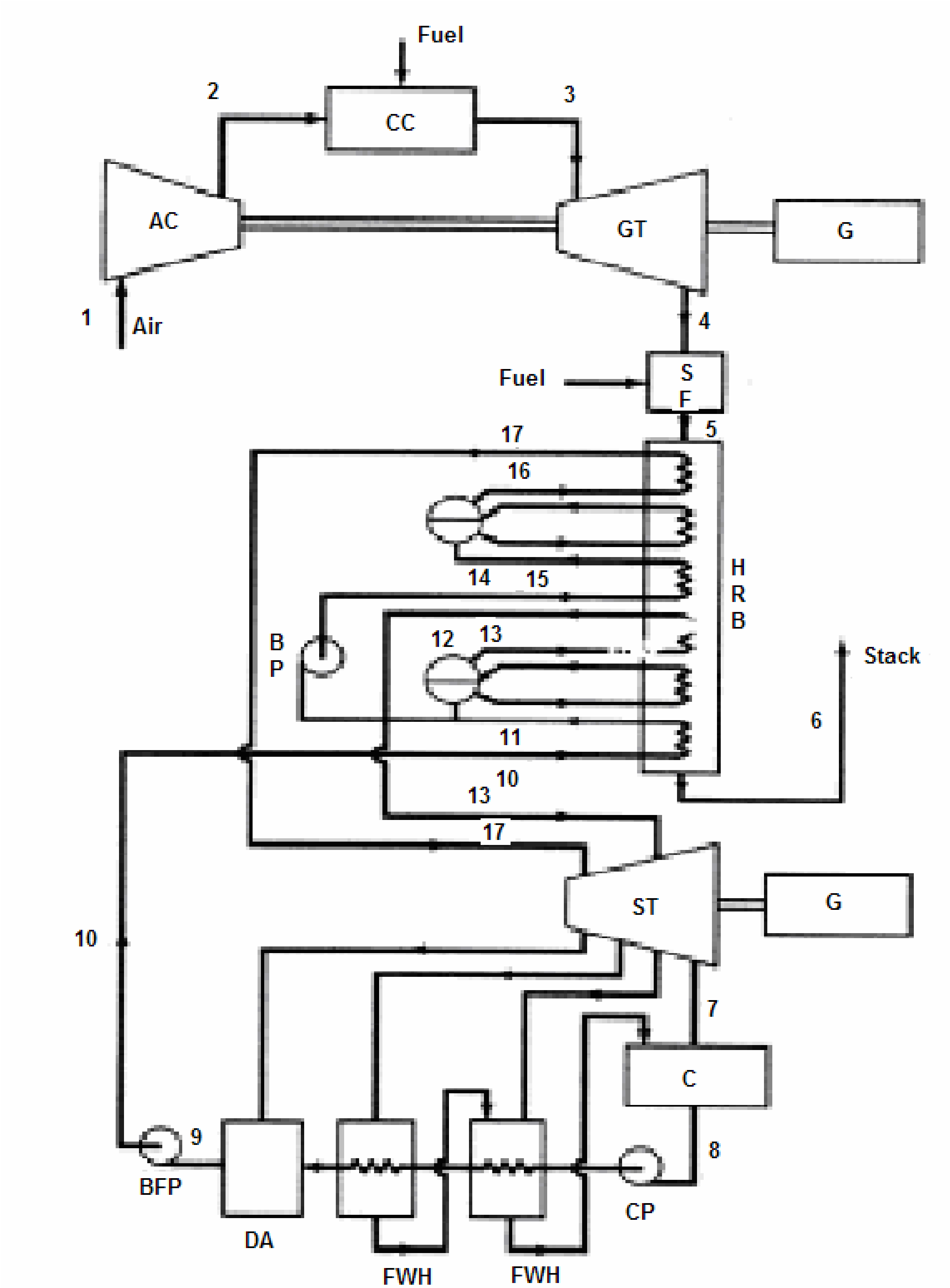


Fig. 70. A schematic diagram for a dual-pressure combined cycle.
Source: Courtesy McGraw Hill, from “Power Generation Handbook”, Kiameh, P.

Combined cycle plants are generally open cycle systems, however CC closed systems are possible if not that common.
The plant system may also incorporate other accessories, such as a gear box (often used to "convert" 60 Hz models to 50Hz models), and/ or subsystems (that may themselves be closed or open systems) such as:

• condensing units, intercooling heat exchangers (for the GT compressor air),
• a regeneration (heat addition) heat exchanger to preheat the GT compressor discharge air,
• reheat heat exchangers (for adding heat to the GT turbine module products of combustion),
• inlet cooling and/or water or steam injection on the GT for power augmentation and/or NO_x reduction,
• a closed or open steam (and/ or air) cooling system (for the hottest areas of the GT turbine module), and
• a supplementary firing system positioned downstream of the GT exhaust to maximize combustion of the exhaust gases (which will include unburned fuel hydrocarbons).

See the block diagram figures below for a representation of GT closed systems, one with regeneration and intercooling, and one with reheat and regeneration. They are followed by a figure that represents a GT open system with water injection and regeneration.

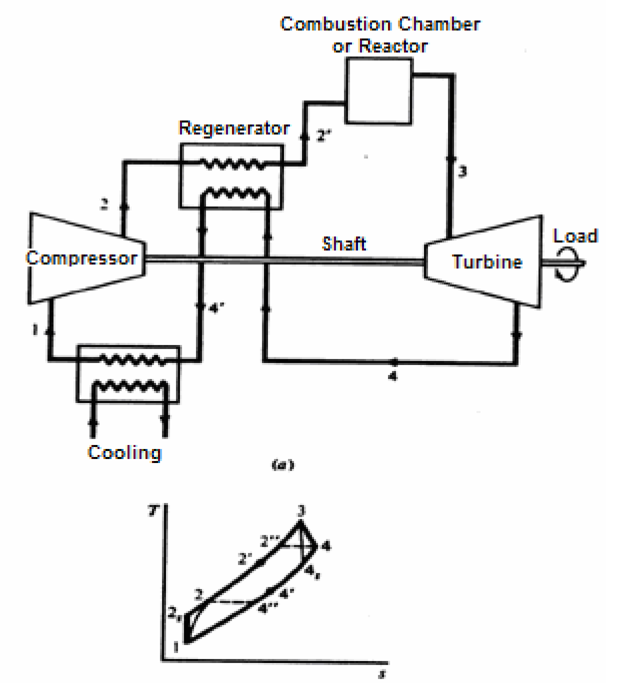


Fig. 71. A Schematic of a GT closed system with regeneration and intercooling. Source: Courtesy McGraw Hill, from "Power Generation Handbook", Kiameh, P.

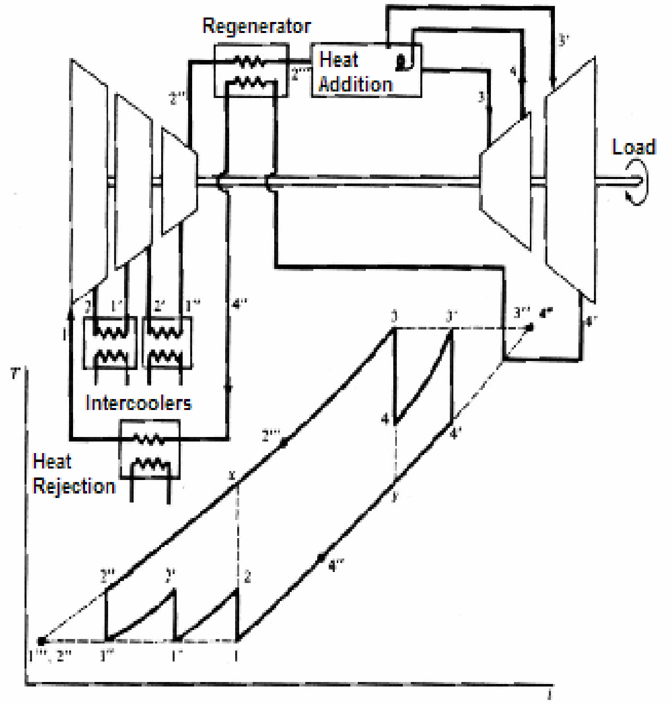


Fig. 72. A Schematic of a GT closed system with regeneration and reheat. Source: Courtesy McGraw Hill, from "Power Generation Handbook", Kiameh, P.

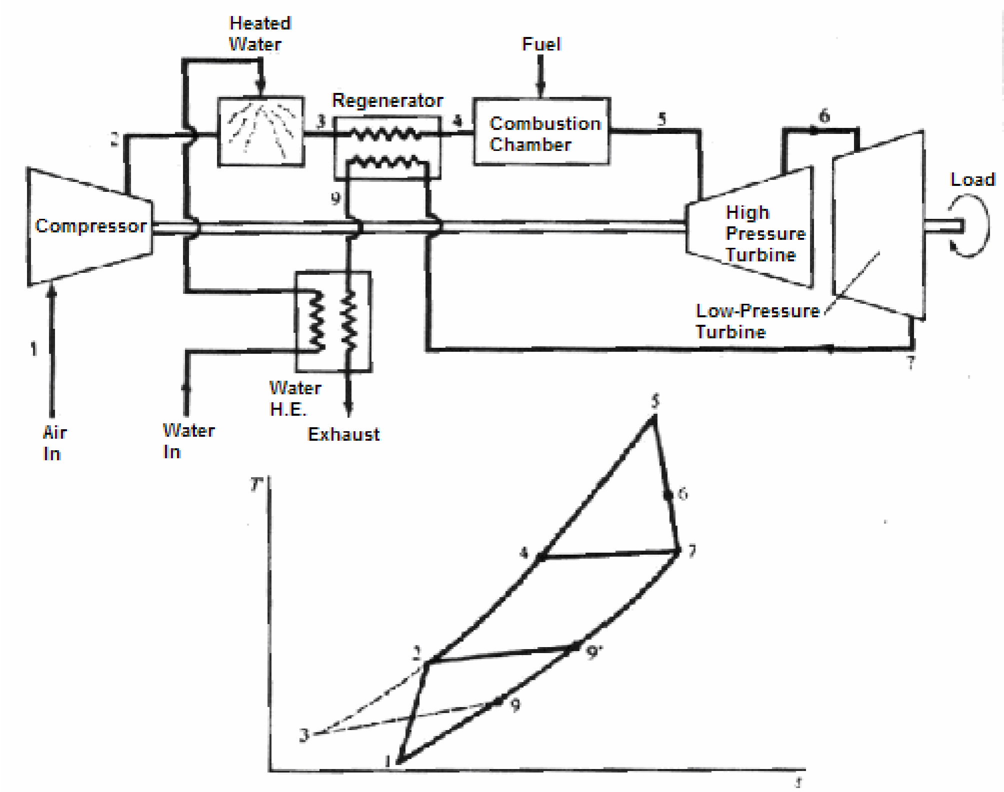


Fig. 73. A Schematic of a GT open system with water injection and regeneration combined cycle plant efficiencies are now typically up to between 58% and 60%. Source: Courtesy McGraw Hill, from "Power Generation Handbook", Kiameh, P.

Gas flapper valves allow the gas turbine exhaust to bypass the heat recovery boiler (HRSG) allowing the gas turbine to operate if the steam unit is down for maintenance. In earlier designs supplementary oil or gas firing was also included to permit steam unit operation with the gas turbine down. This is not generally included in contemporary combined-cycle designs, as it adds to capital cost, complicates the control system, and reduces efficiency.

Sometimes as many as four (but most frequently two) gas turbines, each with individual boilers may be associated with a single steam turbine. As stated previously, the gas turbine, steam turbine, and generator may be arranged as a single-shaft design. A multi-shaft arrangement can also be used: Each gas turbine drives a generator and has its own HRSG, and steam turbine, which in turn, may also add power to the generator.

In areas such as Scandinavia, additional criteria such as cogeneration in combined heat and power plants (CHP) or district heating, as well as demanding conditions (e.g. available space, emissions, noise level, architecture, environmental permits) associated with existing sites and available infrastructure must also be considered. A customer's preferences regarding fuel election, personnel training level required and service requirements must also be accommodated.

Combined Cycle Module Flexibility

With combined cycles, capacity can be installed in modules or module stages. Gas turbines can be commissioned initially (1 to 2 years project construction) and then the HRSG(s) and steam turbine(s) (an additional 6 months to 1 year).

For instance, an Alstom 13E2 CC module can consist of 2, 13E2 gas turbines with heat recovery steam generation and one steam turbine, as in their Kuala Langat, Malaysia plant. In this way, combined cycle capacity can be installed in segments. This further assists generation dispatching, as each gas turbine can be operated with or without the steam turbine. This then provides better efficiency at partial load than operating one large machine with the total capacity equal to the gas turbine(s) and the steam turbine.

Another case[8] illustrating application of the 2, GT and 1, ST module is Alstom's contract for Sohar Aluminum Company for the turn key construction of a 1000 MW gas-fired combined cycle power plant in Oman. The power plant, which will supply electricity to power a new aluminum smelter, will include four 13E2s, four heat recovery steam generators, two steam turbines, six generators. The size of the modules then provides the option for Sohar to add an additional 500 MW of capacity in the future (two GT13E2 gas turbines, two heat recovery steam generators, steam turbine and three generators).

Gas turbine (GT) or combined-cycle (CC) construction cost per kilowatt cost does not increase much for smaller turbines. With steam turbines, it would to a far greater extent, because of the high additional construction work that comes with a steam turbine plant. A CC unit can typically be installed in two to three years, and a steam plant often takes four to five years, with no incremental power available until the complete plant is commissioned.

An application case that illustrates the availability of power in increments is Alstom's recent project award[9] from Australian energy company Alinta Ltd, to supply 2, 172 MW GT13E2 gas turbines for the first stage of a major cogeneration facility at Alcoa's Wagerup alumina refinery in Australia. That power plant will also provide reserve capacity to the new wholesale electricity market in the state of Western Australia. The Alstom turbines will operate initially in open cycle (Wagerup Stage 1). At a later stage, (Wagerup Stage 2), the turbines will be part of a cogeneration plant, operating as a base load power station providing both steam and electricity.

A project[10] database (developed by Siemens KWU) was used to analyze all combined, open cycle and steam power plants globally with respect to capacity (MW), fuel requirements, power system frequency and regional location. The database lists projected orders through 2005. Specific areas of the analysis are summarized as follows:

In terms of overall plant size, 300-600 MW combined cycle plants are the most favored plant size in both 50 and 60 Hz markets (Figure 75). A combination of more than one block improves economics, and 300-600 MW fits well with the demand curve of most power grids in well developed countries. Financiers are also familiar with these economies of scale.

Fig. 74. The 395 MW Combined-Cycle Power Plant Otahuhu, New Zealand uses the modular concept
Source: Siemens Westinghouse

Countries with large grids and high power demand growth prefer combined cycle plants in the range 600 to 2,500 MW. For this combination 2 to 6 parallel units (single shaft or multi-shaft) will suffice. Power systems in countries with relatively small generating capacity, which require smaller capacity additions, need combined cycle power plants in the range 100 to 300 MW. A large gas

[8] Alstom Power Press Release 14 Dec 2005
[9] Alstom Power Press Release 9 Dec 2005
[10] Tailor-made Off the Shelf: Reducing the Cost and Construction Time of Thermal Power Plants. Paul I., (Siemens Power), Karg J. (KWU), O'Leary, Sr. D, (World Bank)

turbine and a steam turbine located on a single shaft can deliver this range. Countries with smaller or specialized grids buy multi-shaft combined cycle plants with several smaller gas turbines with one or more steam turbines. Dirty fuels, for instance residual promote requests for stolid, highly reliable trains that may run derated, over higher efficiency turbines. For peaking power or power systems with very low cost fuels, gas turbines in an open cycle system serve the power range between 50 and 300 MW.

New order forecasts show the market evenly divided between 50 Hz or 60 Hz customers. Rising gas and oil prices everywhere, including the USA, will mean renewed strength in technologies that use alternative fuels, such as pulverized coal, paper liquor waste and steel mill flue gas.

Steam-only (coal fired) Power Plant: The forecast projects 10% of the new orders will be steam power plants in 60 Hz market from 1999 to 2003 (Figure 76). In the 50 Hz market, the key ranges are 300 to 500 MW and 500 to 700 MW. Above 700 MW, supercritical technology represents a small but growing market share.

OEM Modular Strategy

As previously discussed, to save on costs to both OEMs and end users, OEMs have developed modular plants. Siemens has twelve basic power plant combinations (Figure 79); four for open cycle gas turbine plants, six for combined cycle plants and two for coal-fired steam power plants (with sub- and supercritical technology). Each combination covers a specific power range, efficiency, and fuel specification, with allowance for cogeneration system additions.

For design flexibility, options to the reference version for each major functional unit (Figure 80) are provided. For example, “via-ship” is the reference for the functional unit “coal supply” with delivery “via rail” as an option. Flexible design requires breaking down the power plant into functional units, each of which will only directly affect one or two other modules. For a combined cycle plant, the functional units are arranged around the gas turbine and steam turbine. With the gas turbine, as we saw earlier, OEMS strive to maintain core feature commonalities.

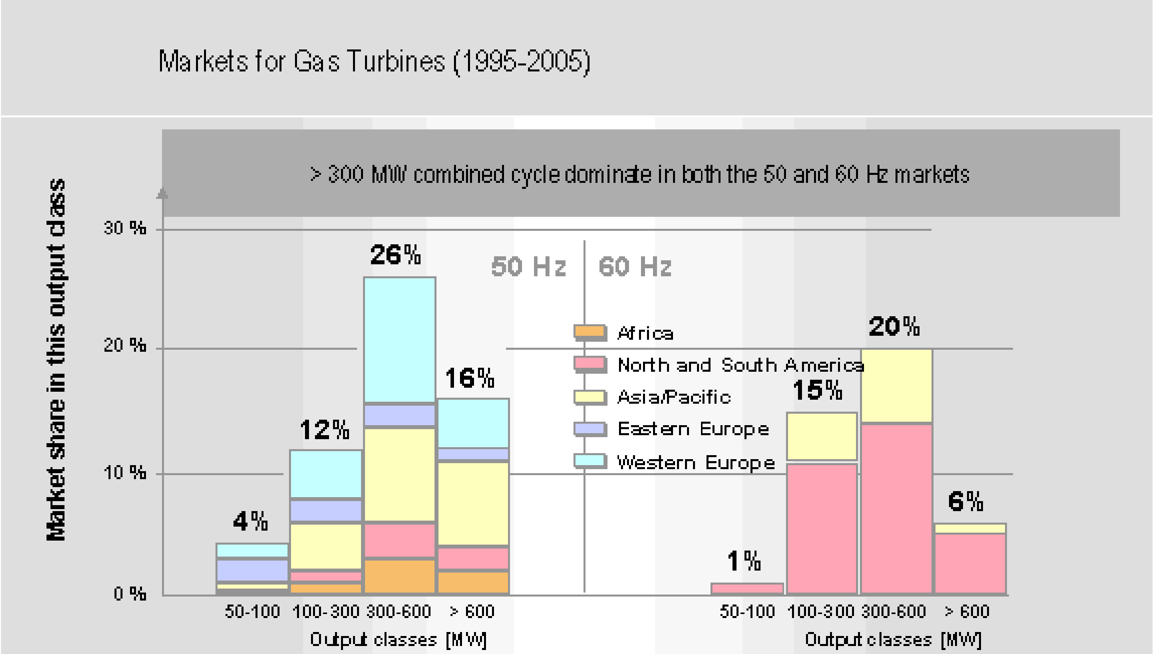


Fig. 75. Markets for Gas Turbines (1995-2005) [10]

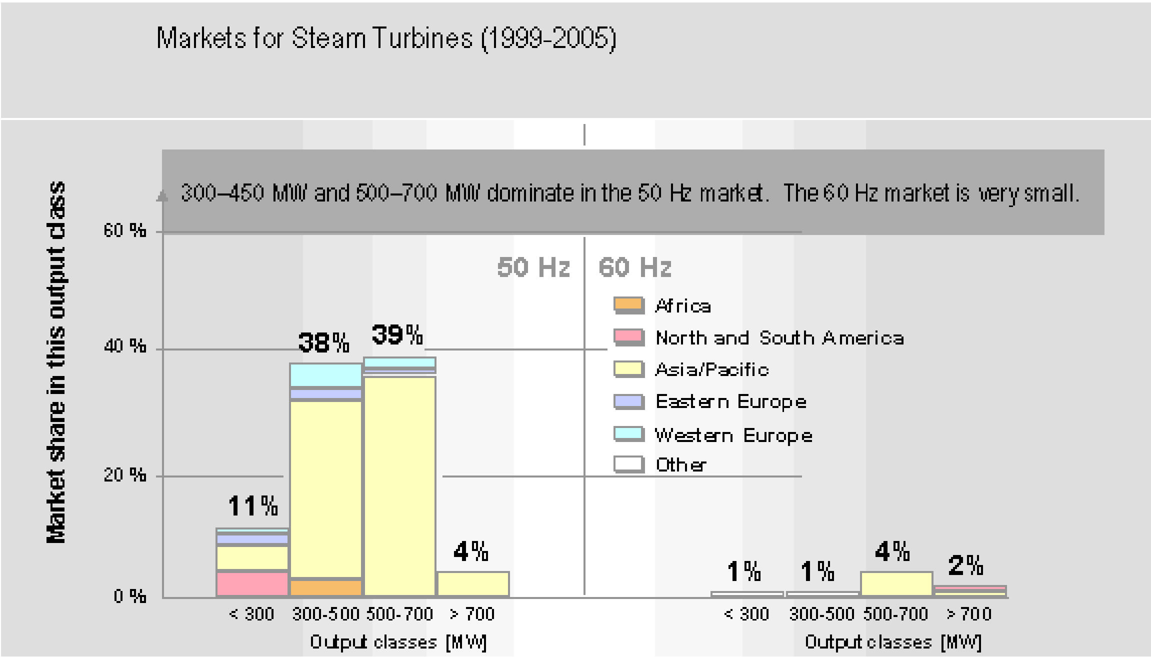


Fig. 76. Markets for Steam Turbines (1999-2005) [10]

Reference Power Plant Data

Ref. Plant Type	Frequency	Output	Efficiency (%)	Fuel
Gas Turbine Power Plants				
GT PP 2.84.2	60 Hz	200-220 MW	33.5-34.0	Gas/Oil
GT PP 2.94.2	50 Hz	300-320 MW	34.0-34.5	Gas/Oil
GT PP 2.84.3A	60 Hz	340-360 MW	38.0-38.5	Gas/Oil
GT PP 2.94.3A	50 Hz	480-510 MW	38.0-38.5	Gas/Oil
Combined Cycle Power Plants				
GUD 1S.64.3A	50/60 Hz	100-105 MW	53.7-54.0	Gas/Oil
GUD 1S.84.3A	60 Hz	250-260 MW	57.8-58.0	Gas/Oil
GUD 1S.94.3A	50 Hz	360-380 MW	57.8-58.0	Gas/Oil
GUD 2.84.3A	60 Hz	500-520 MW	57.8-58.0	Gas/Oil
GUD 2.94.3A	50 Hz	700-760 MW	57.8-58.0	Gas/Oil
GUD 2.94.2	50 Hz	470-480 MW	52.2-52.3	Gas/Oil
Steam Turbine Power Plants				
ST PP 300/450	50 Hz	2x300-2x450 MW	38.0-39.0	Coal
ST PP 500/700	50 Hz	2x500-2x700 MW	40.2-41.6	Coal

Fig. 77. Reference Power Plant Data [10]

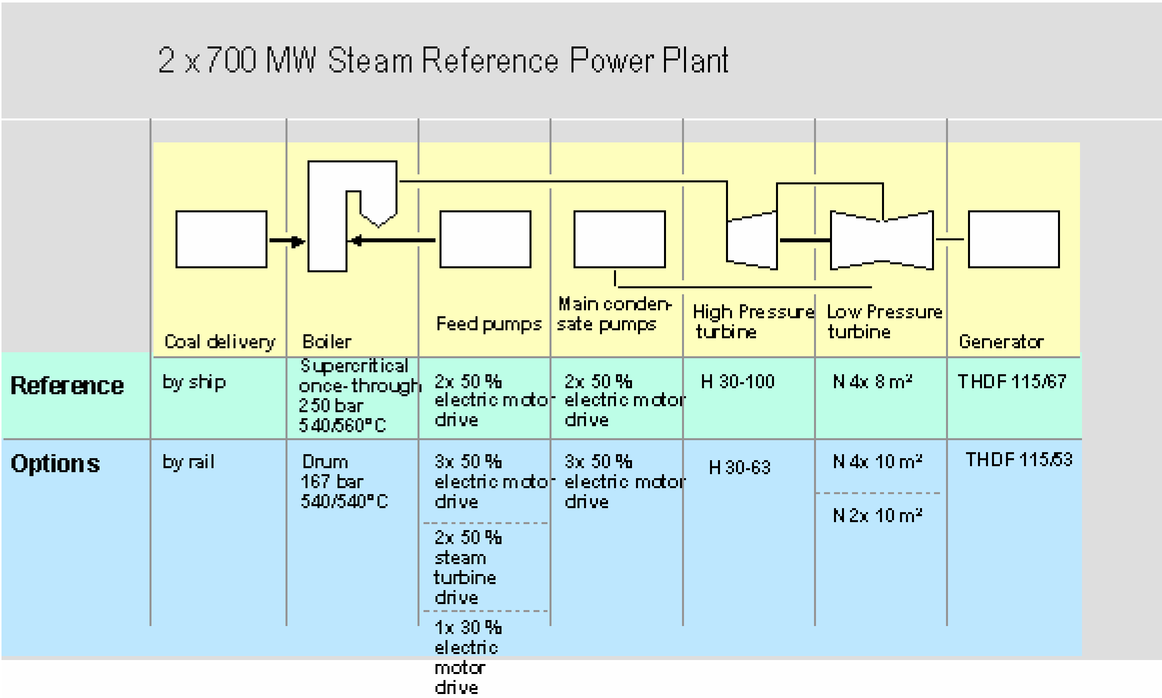


Fig. 78. 2x700 MW Steam Reference Power Plant [10]

Fuels for Combined Cycles[11]

Gas turbine operators prefer to burn natural gas and light oil (diesel, No.2). As we saw previously, crude oil, residual and “bunker fuel contain corrosive components. They require fuel treatment equipment. Also, ash deposits from these fuels can result in gas turbine derating of up to 15 percent. As we also saw previously (in the case of the Shunde plant in south China), they may still be economically attractive fuels, particularly in combined-cycle plants.

Sodium and potassium are removed from residual, crude and heavy distillates by a water washing procedure. A simpler and less expensive purification system will do the same job for light crude and light distillates. A magnesium additive system reduces vanadium.

Note that reduced availability will result due to water cleaning shutdowns to remove blade deposits, as on-line washing, even at reduced speeds, is not effective. A shutdown with a crank soak every 100 to 120 hours is required. Reduced component life due to hot gas path corrosion caused by vanadium deposits and other corrosion is another factor to consider.

Table 7 provides a sample of naphtha- and heavy oil-fired power plants in operation and in the planning stage. As this table shows, some plants (e.g., Kot Addu and Valladolid) have accumulated 30-60,000 hrs of successful operation over their first five years plus.

„Naphtha Class" projects:

Plant Name	Location	Fuel	Gas Turbine Model	Rating	Operating Hours
Paguthan	India	Naphtha, Distillate, NG	3 x V94.2 1 GUD 3.94.2	630 MW	19,000 hours 1)
Santa Rita	Philippines	Naphtha, Condensate, Distillate, NG	4 x V84.3A 4 GUD 1S.84.3A	950 MW	Erection phase
Faridabad	India	NG, Naphtha, HSD	2 x V94.2 1 GUD 2.94.2	440 MW	Engineering phase

Note : 9 Gas Turbines ordered for fuels of "Naphtha Class". "Naphtha Class" means light, low boiling liquid fuels

Latest plants with ash-forming fuels:

Plant Name	Location	Fuel	Gas Turbine Model	Rating	Operating Hours
Valladolid	Mexico	Residual oil	2 x V84.2 1 GUD 2.84.2	220 MW	24,000 hrs
Kot Addu	Pakistan	Furnace oil (Heavy oil)	4 x V94.2 2 GUD 2.94.2	820 MW	60,000 hrs
Rousch	Pakistan	Heavy oil	2 x V94.2 1 GUD 2.94.2	390 MW	Commissioning phase

Note : 34 Gas Turbines delivered for ash-forming fuels in total Accumulated operating hours approx. 140,000 hours

Table 7. Naphtha- and heavy oil-fired power plants in operation and planning stage [11]

Design and operation of these plants requires more attention than natural gas fired plants particularly in relation to fuel variables such as calorific content, density, composition, concentration of contaminants and emissions, as well as different burning behaviors (e.g. ignitability, flame velocity and stability).

To overcome these difficult fuel properties, technological adaptation, additional equipment and operational requirements are necessary. These include GT layout (compressor, turbine) for the changed mass flows, different burner technology (burner design, burner nozzles), additional startup/shutdown fuel system, and safety measures. Performance, availability and operation & maintenance (O&M) expenses can be affected. To illustrate this, Table 11 shows some key non-standard fuels and their effect on a standard fuel system.

[11] Gas Turbine Power Plants: A Technology of Growing Importance for Developing Countries. Taud R., (Siemens Power), Karg J. (KWU), O'Leary, Sr. D, (World Bank)

Table. 8. Gas Turbines for None Standard Fuels Critical Fuel Properties[11]

Critical fuel properties	Fuels	Effect on standard fuel system
• Low viscosity (reduced lubricity) • Low density (high volume flow)	Naphtha, Kerosene, Condensates Naphtha, Condensates	Effect on fuel supply system (e.g. pump design) Limits for fuel supply system and burner nozzles
• Low flash point • Low boiling point (high vapour pressure)	Naphtha, Kerosene, Liquefied Petroleum Gases (LPG) High Speed Diesel (HSD), Condensates	Increased explosion protection effort, Increased ventilation effort
• Low auto ignition point • Contaminants (high temperature corrosion, ash deposits)	Naphtha, Condensates, Contaminated fuel oils, Crude oils, Heavy oils, Heavy residues	Effect on premix capability Increased explosion protection effort. Increased ventilation effort Effect on GT blading and hot gas path, Counter-measures: - Temperature reduction (reduced performance) - Fuel treatment (washing/inhibitor dosing)
• Low heating value (high volume flow)	Process and synthesis gases (low calorific gases), Low BTU natural gas	Effect on layout of GT compressor, burner nozzles, fuel supply system
• High heating value (low volume flow) • High H_2 content	LPG, gaseous and liquid Process and synthesis gases (low calorific gases)	Effect on layout of burners, fuel supply system Limited start-up and part-load capability High flame velocity, Effect on premix capability
• High dewpoint	Gases with high boiling components	Droplets causes erosion and non constant heat flow

An example of gas turbine combined cycle plant burning a non-conventional is the 220 MW Valladolid plant in Mexico. This plant, commissioned in 1994, burns heavily contaminated fuel oil, containing 4.2% sodium and up to 300 ppm vanadium. Fuel impurities (sodium, potassium and vanadium), tend to form ash particles in the combustion process, form deposits and corrode the gas turbine blades. In the case of the Valladolid plant, "Epsom salts", consisting mainly of magnesium sulfate ($MgSO_4$ 7 H_20), is dissolved in water injected into the gas turbine combustor through special orifices. This converts the vanadium into a stable water-soluble product (magnesium vanadate). This is deposited downstream of the combustor on the gas turbine blades, and causes only minor blade corrosion. To prevent major performance loss with salt build up (as with the Shunde, China plant that we read about previously); washing every 150 hrs was necessary to restore aerodynamic performance and plant efficiency. Good manhole access was a critical success factor for this project as servicing and maintenance during turbine washing shutdowns are simplified. (The plan is to eventually convert the Valladolid plant to natural gas operation).

Factors that affect Costs per Fired Hour[11]

Fuel type and mode of operation (steady load/ partial load) will determine maintenance intervals and the maintenance work items required. Some estimate that burning residual or crude oil will increase maintenance costs by a factor of 3, (assuming a base of 1 for natural gas, and by a factor of 1.5 for distillate fuel) and that those costs will be three times higher for the same number of fired hours if the unit is started every fired hour, instead of starting once very 1000 .fired hours. "Peaking" at 110 percent rating will increase maintenance costs by a factor of 3 relative to base-load operation at rated capacity, for any given period.

The control system on combined cycle units is automatic. When an operator starts the unit, it accelerates, synchronizes and loads "by itself". Fewer operators are required than in a steam plant.

Trends in Global Combined Cycle Installations[11]

A few hundred power generation plants are ordered from about a dozen OEMs every year. This means the market is exceptionally competitive. Given that most of the new plants are going into newly developing countries, the biggest factor in determining the winner of each project (bid on by several OEMs or not) is the financial deal the OEM can put together for the end user.

As one might expect, maintenance costs are higher for any type of plant in countries that have not had as much exposure to the OEMs technology. As a significant extension of their revenue, OEMs offer overall “power by the hour” maintenance contracts. These costs vary, even for the same basic modular configuration and mechanical design, depending on the location’s demographics. So then will the actual and contractually set “cost per fired hour” figures. There would be a significant difference between what actual operational costs are for the same OEM’s CC block in a well developed area of the USA and a remote area in Azerbaijan, for instance. Demographics also alter construction costs. (As an illustration, in 1990s figures, costs varied from $592/kW for a new 1,080 MW combined-cycle plant in Egypt to $875/kW for a steam addition to convert four gas turbines in Pakistan to a combined-cycle plant, according to World Bank data). OEMs are aware that end users compare cost data at various meetings and forums, and that price variations are a sore and much negotiated point. Therefore OEMs continually strive to optimize designs and assembly methods to minimize the steepness of new operators’ learning curve.

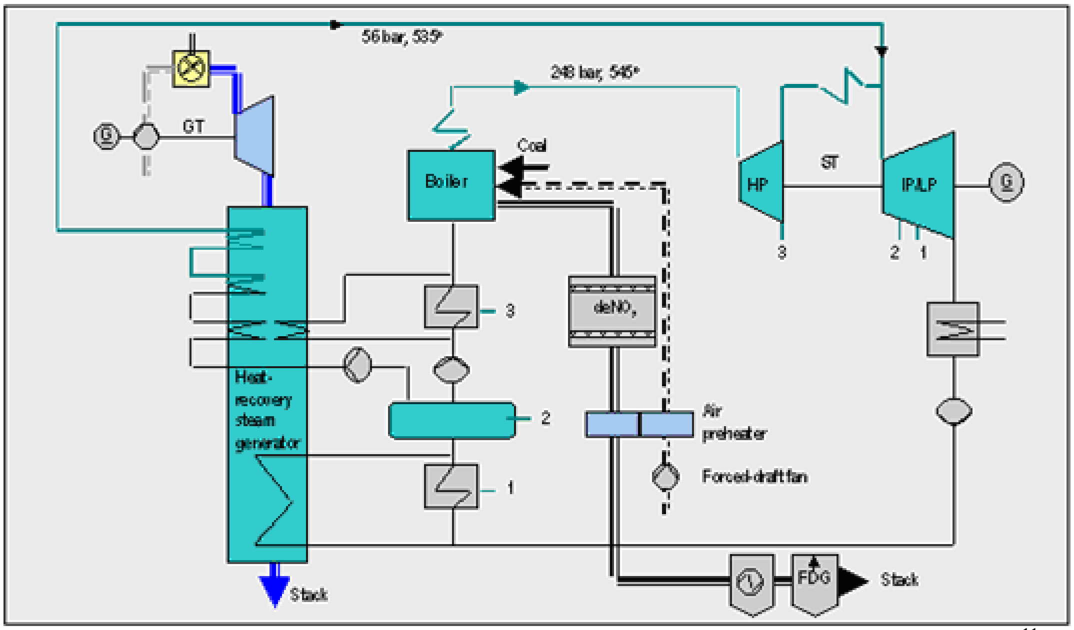


Fig. 79. Schematic Diagram of a Parallel Combined Cycle Block with Full Flue Gas Cleaning [11]

“Modularization” (for instance the Siemens Westinghouse GUD block which is 2, V94.3 gas turbines, their HRSG boiler capacity and a steam turbine) reduces construction costs. Compared with the customized design and construction, modularization can reduce project costs of detailed engineering, material price contingencies and financial loan interest during construction.

Downsizing power delivery (to the grid) requirements will change overall operational cost figures. “Repowering” will change operational statistics significantly. Repowering is a term used to define
the reconfiguration of a power station. It may mean replacing a steam turbine with a gas turbine or combined cycle. One example of a repowering option offered by an OEM is Alstom’s combining their 181 MW GT24 gas turbine with a dual pressure reheat cycle consisting of a 70 MW LP/IP steam turbine and a 20MW HP steam turbine, to generate a total of 270 MW.

The most common configuration is called (Figure 79) parallel powering, where the gas turbine exhausts are used in the existing steam cycle. This is achieved by feeding the exhausts into a heat-recovery steam generator (HRSG) which provides additional steam to the existing steam turbine. Typically, parallel powering requires the addition of a gas turbine, associated electrical and instrumentation and control equipment, civil engineering, HRSG, additional piping and pumps as well upgrading the steam turbine. Generally, parallel powering can be undertaken fairly separately from the existing part of the plant, with a final integration phase and a plant down time of 1.5 to 2 months. The typical cost range is US 300-500/kW.

In some cases, national or international markets alter a power plant’s budget by changing available fuels. An example would be the United Kingdom’s temporary moratorium on their indigenous natural gas (which promoted coal for that period). When the decision was made to allow North Sea petrochemical liquid deposits to vaporize and be delivered as gas instead, that move created operational ripples in all industries that used petrochemical fuel, including power generation.

Since the late eighties[10], market growth in plant additions/ optimization technology retrofits has shifted in part, from Europe, North America and Japan to newly industrializing countries in Asia and Latin America. Financial means keep many of the end users in these regions from using newer technologies that would extend their power generation capacity and reduce their costs per fired hour. Nevertheless, they are becoming increasingly aware of these design developments and do seek to incorporate them where and when possible.

For the OEM, the main challenges are minimizing project cost, construction time and risk guarantees (Figure 80). Between the 1980s and 2000, project cost and construction time of coal and gas fired units have dropped by 50%. However, to compete, OEMs must offer better warranty packages. So the standardization of core design to minimize spares costs, make factory assembly methods and repair and overhaul methods "foolproof" increases in importance.

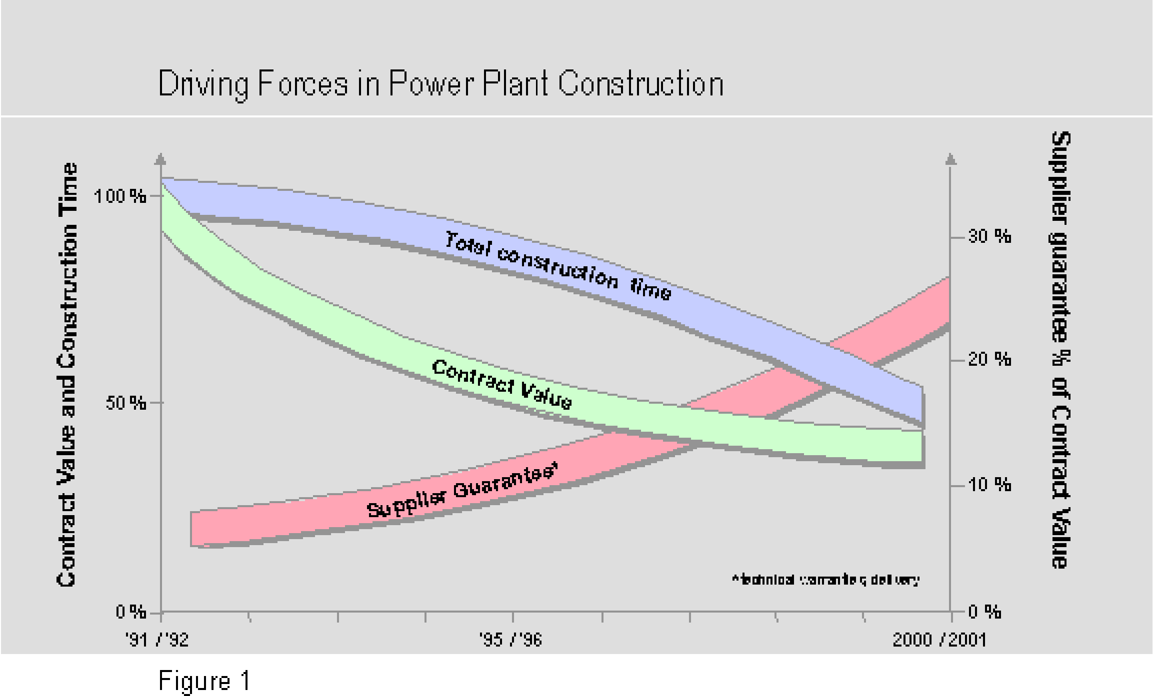


Fig. 80. Driving Forces in Power Plant Construction [10]

Figure 81 shows[11] the cost breakdown for combined cycle plants (350 MW-700 MW capacity) based on Siemens experience into the following categories: integrated services (project management/subcontracting; plant and project engineering/project management software, plant erection/commissioning /training; transport/insurance) and lots (civil works; gas- and steam-turbine and generator sets; balance of plant; electrical systems; instrumentation and control systems; and the boiler island).

Integrated Services		
	4%	Project Management/Subcontracting
	2%	Plant and Project Engineering/Software
	8%	Plant Erection/Commissions/Training
	1%	Transport, Insurance
	∑15%	

Lots		Civil Works	Gas- And Steam Turbine Set	Balance of Plants	Electrical Systems	Instrumental And Control	Boiler Island
	∑85%	15%	32%	16%	7%	4%	11%

Basis : 350/700 MW CC Plant with a V94.3A Gas Turbine

Fig. 81. Cost Breakdown for CC Power Plants [11]

The Changing Power Generation Market[11]

From 1994 to 1999, power plant contract awards for fossil fuel-fired power plants (above 50 MW) averaged 63 GW per year. In 1999, sales were forecasted to average about 67 GW per year over the period 1999-2004. The market in the Asia Pacific Basin was declining, while showing a moderate growth in Europe and (starting from a low level), strong growth in North America.

In comparison with coal fuelled power plants, open and closed cycle power plants are characterized by lower investment costs. However, USA fuel related costs (i.e. fuel price and plant efficiency) have changed with the rise in oil and gas prices in the USA that was precipitated by the Iraq war and hurricane Katrina. At the turn of the century gas prices ranged from about US$ 2.0/GJ to US$ 4.5/GJ, with the North American prices being at the lower end of the range.

The only fact that anyone will sign their name to, in terms of oil and gas prices in 2006, is that they will go up. One Canadian forecast agency suggests that gas prices in 2006 in Canada will stay at about C$8/GJ. This then means that the fierce inter-OEM rivalry with respect to fuel efficiency will escalate.

Three major infrastructure changes continue to drastically alter the face of the power generation industry and directly or indirectly promote technological innovation. They are:

Deregulation: This then means that independent power producers (IPPs), some of them small power producers (SPPs), help make large plant new construction or expansion unnecessary. Consider the earlier examples of the PCS Company’s use of what were Alstom Power GT10s (this model was part of the Siemens Westinghouse acquisition of Alstom’s smaller engine divisions) in combined cycle operation. The waste hydrocarbon fluids they used as fuel, helped further develop low BTU fuel technology experience. Many SPPs can sell their excess power back to the utility grid.

OEMs as IPPs: Most of the major OEMs have joint ventures all over the world that involve power generation. They provide training to their local partners and thus promote employment and technology to newly industrialized countries. Two examples are the Siemens-YTL partnership for power stations in Malaysia and the Alstom Power-Genting joint venture for the Kuala Langat station. The Kuala Langat station also provided a good example of cogeneration as it sells its excess steam to a nearby mill.

Oil companies as IPPs: Shell in the United Kingdom is a good example of a growing trend. As IPPs, oil companies can be their own customer for their oil and gas. This then short circuits much of the Fuel Purchase Agreement contractual formalities that other IPPs have to negotiate.

Integrated Gasification Combined Cycle (IGCC) Plants[11]

IGCC plants consist of three main sections:

• the "gas island" for conversion of coal and/or refinery residues (such as heavy fuel oil, vacuum residues or petroleum coke). This includes gasification and downstream gas purification (removal of sulfur and heavy metal compounds in accord with required emissions levels),
• the air separation unit and
• the combined cycle plant. The modular design (gas generation, gas turbine system, HRSG and the steam turbine system) allows phased construction as well as retrofitting of the CC plant with a gasification plant. This replaces the "standard" gas turbine fuels (natural gas or fuel oil) by syngas produced from coal or refinery residues.

IGCC is a combination of two proven technologies, however proper integration depends on using the lessons learned form several demonstration projects in Europe and the USA. Currently, there are more that 350 gasifiers operating commercially worldwide and at least seven technology suppliers. There are about 100 CC units plants ordered per year, but there is limited experience of IGCC commercial operation. Currently, we refer to operating experience at five IGCC plants: the 261 MW Wabash River plant; the 248.5 MW Tampa plant; the 253 MW Buggenum plant; the 99.7 MW Pinon Pine plant and the 318 to 300 MW Puertollano plant. IGCC will see commercial application in developed countries, such as Italy, for residual refinery fuels and gasified coal. However, great care needs to be taken in implementing a commercialization strategy for developing countries.

Through 2015, the potential for refinery-based integrated coal gasification combined cycle (IGCC) plants is estimated to be 135 GW. Currently over 6GW of coal and refinery residue based IGCC projects are either, under construction or are planned. Figure 85 shows some of the IGCC plants that are planned or under construction.

Technology/Performance/Environment /Demand Trends[11]

Figure 82 compares the supply flows, emissions and by products of different 600 MW-class plants. With environmental emissions (including greenhouse gases, GHG), IGCC plants compare well with pulverized coal-fired steam power plants.

Depending on the degree of integration between the gas turbine and the air separation unit (ASU), either standard gas turbine/compressor configurations can be applied. If not, the mismatch between turbine and compressor mass flows which results from the application of gases with low heating values, limited modifications are required to compensate.

Three options are available. The selection of the appropriate air and nitrogen integration concept depends on a number of factors to be considered on a case by case basis. A summary of the important criteria is provided in Figure 83

Figure 84 sets out the principal criteria for selection of the different IGCC integration concepts. The “fully integrated approach” (selected for the European coal-based demonstration plants) results in the highest efficiency potential, but it can prove more difficult to operate.
Nevertheless, after some initial operational problems, the Buggenum IGCC facility has demonstrated that design can provide good availability.

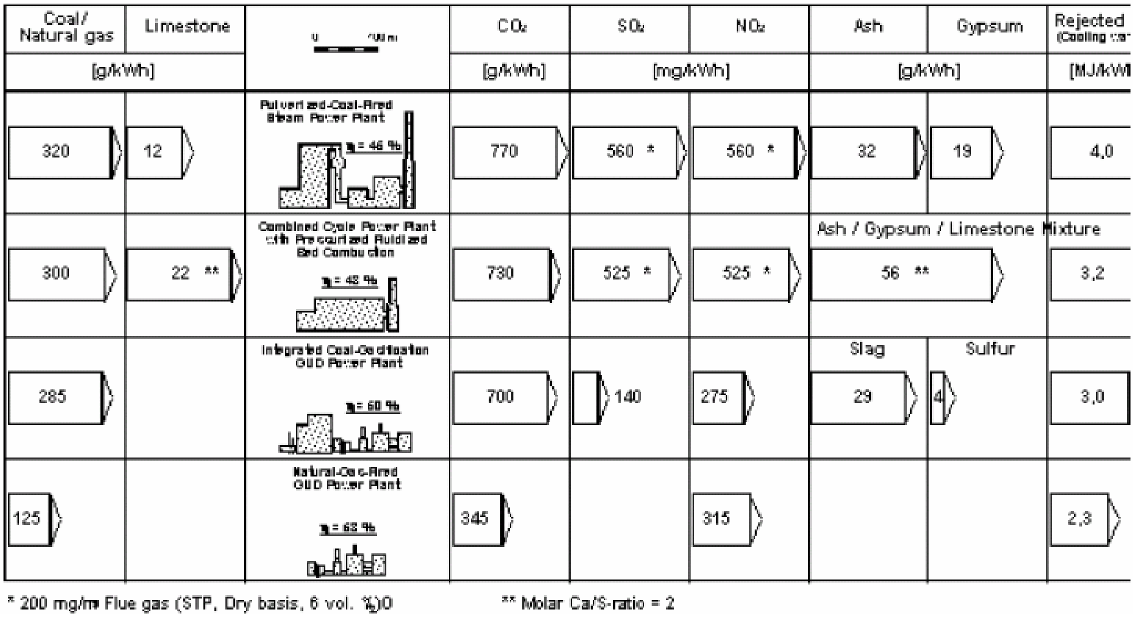


Fig. 82. Comparison of Supply Flows, Emissions and Byproducts of Different 600 MW - Class Power Plants [11]

Integration Options

1. Non-integrated (independent) ASU
2. Partially integrated ASU
3. Fully integrated ASU

Criteria for Selection of the Integration Concept

- Gasification process and waste heat recovery (syngas cooler, quench, cooler/saturator cycle)
- ASU process
- Fuel gas analysis (with or without nitrogen return)
- Limits for NO_x emissions
- Overall plant efficiency
- Investment costs
- Operational aspects
- Site-specific aspects
- Necessary modifications of standard gas turbines
- Available fuel flow

Fig. 83. Main Criteria for Selection of the IGCC Integration Concept [11]

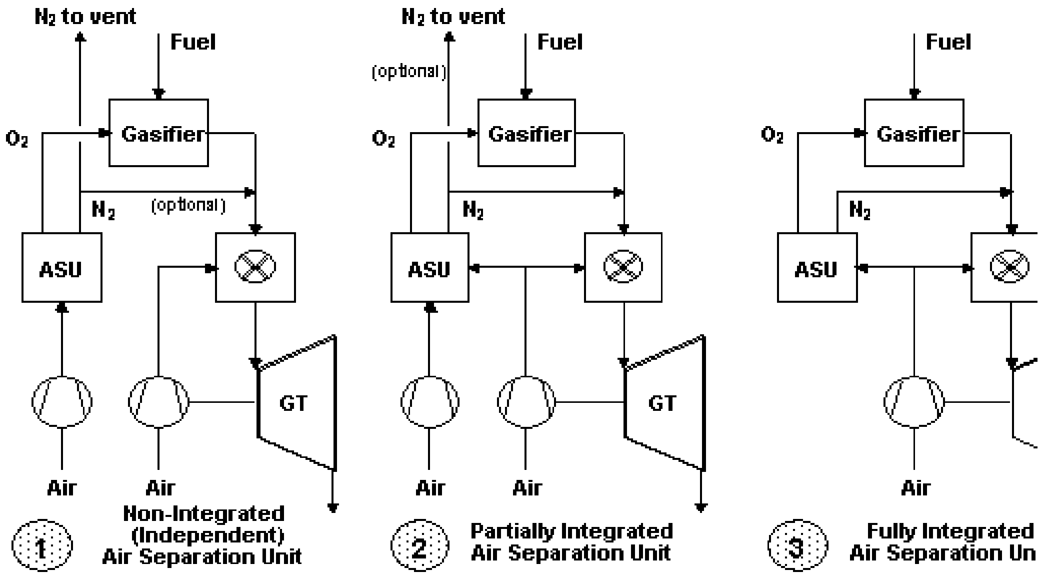


Fig. 84. Integrated Options for IGCC Power Plants [11]

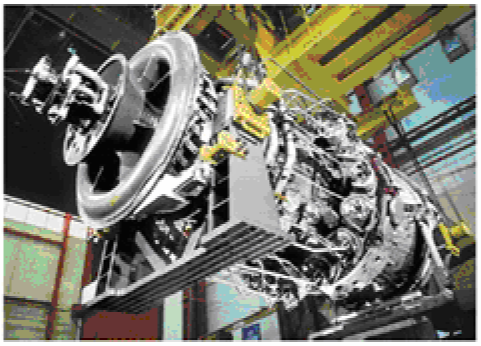
The non-integrated concept with a completely independent ASU is simpler in terms of plant operation and possibly in achievable availability. However, the loss in overall IGCC net plant efficiency compared with the fully integrated concept is 1.5 to 2.5 percent. So this concept is of interest for applications where efficiency is not the key factor (e.g. for the gasification of refinery residues).

The concept with partial air-side integration is a compromise, with an only moderate loss in efficiency but improved plant flexibility, when compared with the fully integrated concept.

Here are two examples of gas turbines that can be incorporated into combined cycle packages.

Technical features:

- 16 can-type combustors in a circular array
- Optional multiple fuels capability
- 16-stage axial-flow compressor with advanced 3D design technology
- Low-NOx combustion system
- Variable inlet guide vanes
- Cooled, filtered rotor cooling air
- Four-stage turbine
- Steam power augmentation (optional)
- Advanced cooling technology



The SGT6-5000F gas turbine has more than 1,000,000 hours of fleet operation. It can be used in either simple-cycle or heat recovery applications including cogeneration, combined cycle and repowering. The SGT6-5000F provides on-line generation for peaking duty, intermediate operation or continuous service.

Fig. 85. Siemens SGT6-5000F (198MW, 60Hz) Simple cycle,
Combined cycle, and other cogeneration applications
(Source: Siemens Westinghouse)

The SGT5-2000E is used for simple or combined-cycle processes with or without combined heat and power, and for all load ranges, particularly peak-load operation.

For Integrated Coal Gasification Combined Cycle (IGCC) applications, Siemens Westinghouse provide the SGT5-200E (LCG) machine - the 2-type machine with modified compressor. The SGT5-2000E has more than 120 units in operation accounting for approximately 70,000 starts and more than 4,000,000 operating hours.

Technical features:

- Horizontally split casing
- Four stage turbine
- Two walk-in combustion chambers for hot-gas-path inspection without cover lift
- All blades removable with rotor in place
- Combustion chambers lined with individually replaceable ceramic tiles
- Hybrid burners for premix and diffusion mode operation with natural gas, fuel oil and special fuels such as heavy oil and refinery residues
- 16-stage axial-flow compressor with variable-pitch inlet guide vanes
- Low-NOx combustion system
- Optional fast inlet guide vanes for peak load operation and frequency stabilization

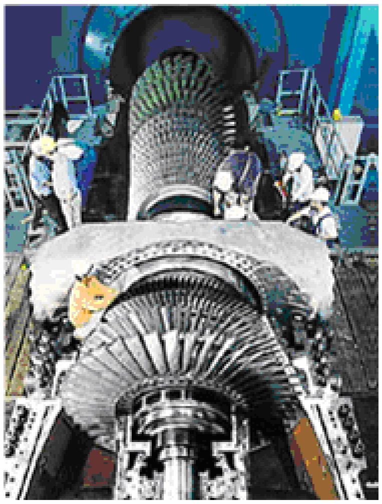


Fig. 86. Siemens SG T5-200E (163 MW, 50 Hz) Simple or combined cycle and other cogeneration applications
(Source: Siemens Westinghouse)

BIOGRAPHY

Simple and Combined Cycles

A professional engineer registered in Texas, and a Fellow of the American Society of Mechanical Engineers, Claire Soares has worked on rotating machinery for over twenty years. Soares' extensive experience includes the specification of new turbomachinery systems, retrofit design, installation, commissioning, troubleshooting, operational optimization, and failure analysis of all types of turbomachinery used in power generation, oil & gas, petrochemical & process plants and aviation. The land-based turbines (gas, steam or combined cycle) in question were typically made by General Electric, Alstom power, Siemens Westinghouse, Rolls Allison, Solar and the companies they formerly were, before some of them merged.

Her career experience also includes intensive training programs for engineers and technologists in industry. Her specialty areas include turbomachinery diagnostic systems as well as failure analysis and troubleshooting.

In her years spent with large aircraft engine overhaul and aircraft engine fleet programs in the USA and Canada, Soares worked on turbine metallurgy and repair procedures, fleet asset management and aeroengine crash investigation. She also was engineering manager for the first overhaul program in the USA for the V2500 engine (commissioned 1991).

Gas turbines (land, air and sea) are Ms. Soares' primary area within the turbomachinery field. Her perspective with respect to gas turbines is that of an operations troubleshooter with extensive design experience in gas turbine component retrofits/ repair specification and retrofit system design development.

Claire has authored/ co-authored six books for Butterworth Heinemann and McGraw Hill on rotating machinery (**See the links below for book details). She also writes as a freelancer, for various technical journals, such as Independent Power Generation and European Power News (U.K. based publications).

Ms. Soares has an MBA in International Business (University of Dallas, TX), and a B. Sc. Eng. (University of London, external). She is a commercial pilot. Her scuba diving certification and training were in high altitude conditions. She has lived and worked on four continents. Her "non-engineering" time is partly spent on cinematography and still photography.

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