7 COMBUSTION TECHNIQUES FOR GASEOUS FUELS

7.1 Applied processes and techniques

7.1.1 Unloading, storage and handling of gaseous fuels

Gaseous fuels are delivered to LCPs via pipeline, either from the gas-well or from liquid natural gas decompression and storage facilities. Natural gas from different wells varies in quality. Often gas clean up may occur at the production site to reduce transport problems in pipelines. Figure 7.1 shows the European natural gas network, indicating the pipelines integrated into the European system. The pressure in the main pipeline systems is 80 bar.

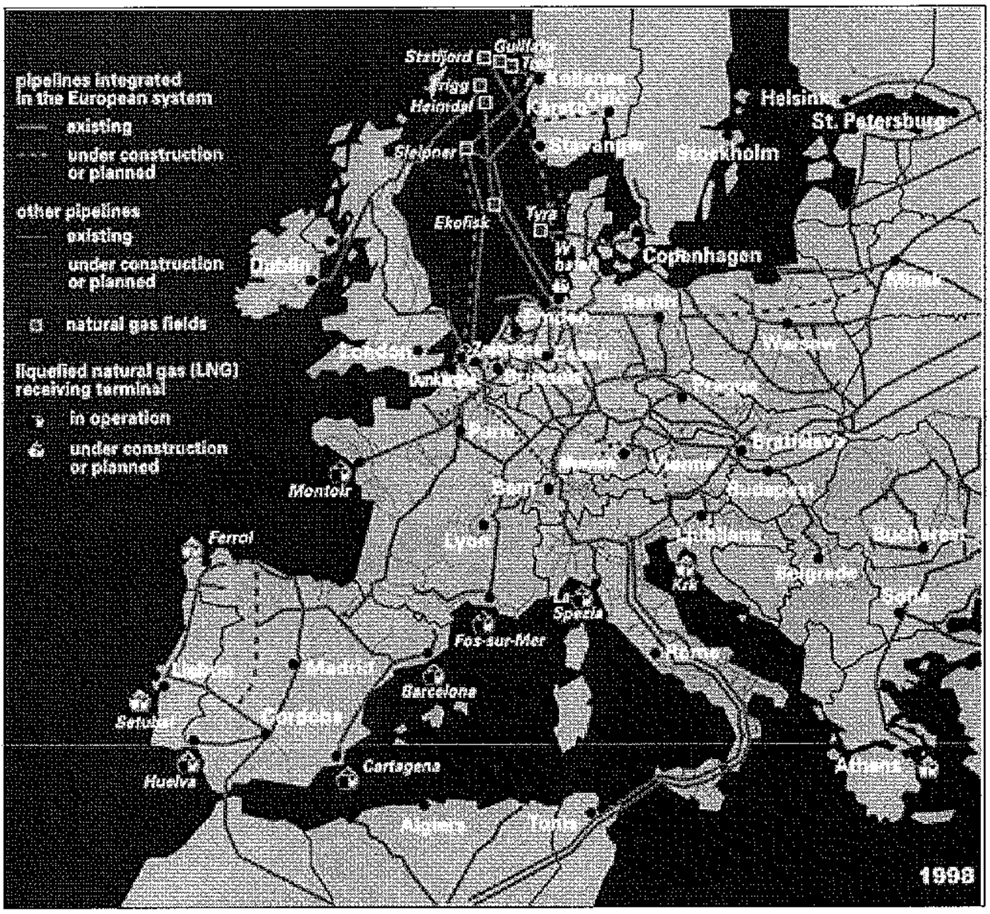


Figure 7.1: European natural gas network
[111, Eurogas, 1998]

The gas supplier usually provides centralised storage capacities for natural gas. At some sites, for existing LCPs, separate storage tanks still exist. Gas storage tanks are often located near to CHP units, but are used for public gas supply. On-site gas storage at LCP sites for new plants is not practised. Distillate is most commonly used as the back-up fuel in such circumstances and is stored on-site.

A range of gases may be used in gas combustion plants. If the pressure of the supply pipeline exceeds the required input pressure of the LCP, the gas needs to be decompressed. This normally takes place in an expansion turbine in order to recover some of the energy used for compression. Waste heat from the power plant can be used to heat up the decompressed gas and thus to increase electricity output. Fuel gas is then transported in pipes to the LCP.

Gas turbines only use clean gases for direct firing. Here also, natural gas may have to be decompressed if the pressure of the pipeline exceeds the required input pressure of the gas turbine. Adiabatic cooling of the expanded gas can be used to cool the fresh air entering the gas

pressurised to the necessary input pressure of the combustion chamber of the particular gas turbine.

7.1.2 Gas turbines (GT)

Gas turbines are used for the transformation of chemically bound fuel energy into mechanical energy. They are applied for the production of electrical energy and to drive pumps and compressors. The number of gas turbines used worldwide has grown significantly during the last decade, and nowadays gas turbines are increasingly used for electricity production in base and intermediate loads. This increase may be explained by the abundant supply of natural gas at a favourable price and by the development of a new generation of gas turbines with higher output, efficiency, and reliability. Figure 7.2 shows a breakdown of gas turbines by firing mode worldwide.

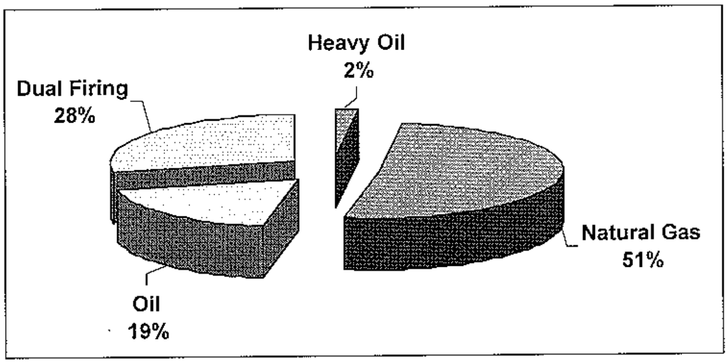


Figure 7.2: Firing mode of gas turbines – worldwide status [32, Rentz, et al., 1999], [164, Lenk and Voigtländer, 2001]

Gas turbines are used within a wide range of thermal capacities, from small gas turbines at about 100 kW_e up to large gas turbines of 310 MW_e. Gas turbines can be fuelled with various gaseous fuels and liquid fuels. Natural gas is the usual gaseous fuel for gas turbines, but gases with low or medium calorific value are also applied, such as coal gas from coal gasification units, gas from blast furnaces and gas from biomass gasification units. Heavy duty gas turbines are capable of burning a variety of liquid fuels, from naphthas to residuals. Operating with ash-forming fuels, such as crude and residual oils, requires comprehensive treatment systems. The requirements applied for liquid fuels to be fired in gas turbines are described in Section 6.1.7.

Gas turbines are installed in different types of combustion plants such as combined cycle units, co-generation plants and integrated coal gasification units. Aeroderivative gas turbines are available up to 50 MW_e with efficiencies of up to 42 %. They are also largely used on offshore platforms. Heavy duty gas turbines (Figure 7.3) with power outputs from 200 – 300 MW_e can reach efficiencies of up to 39 %.

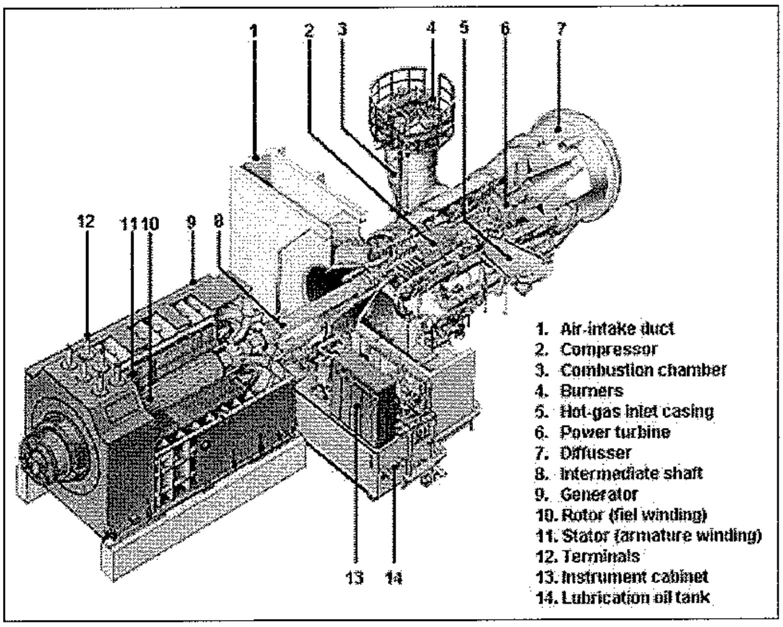


Figure 7.3: Heavy duty gas turbine electricity generating unit
[104, Siemens, 2001]

The application of new gas turbines in combined heat and power units is increasing in an attempt to improve overall efficiency and emissions. As the efficiency of single cycle gas turbines varies from approximately 30 to 42 %, the efficiency of combined cycles can be up to 58 %, while application in a combined heat and power station, fuel utilisation values of 85 % can be obtained. It should be emphasised that the efficiency values mentioned apply to new, clean gas turbines at full load and under ISO conditions. At other conditions, the values may be significantly lower. The rapid development of gas turbines is expected to lead to even higher efficiencies and power output in the future.

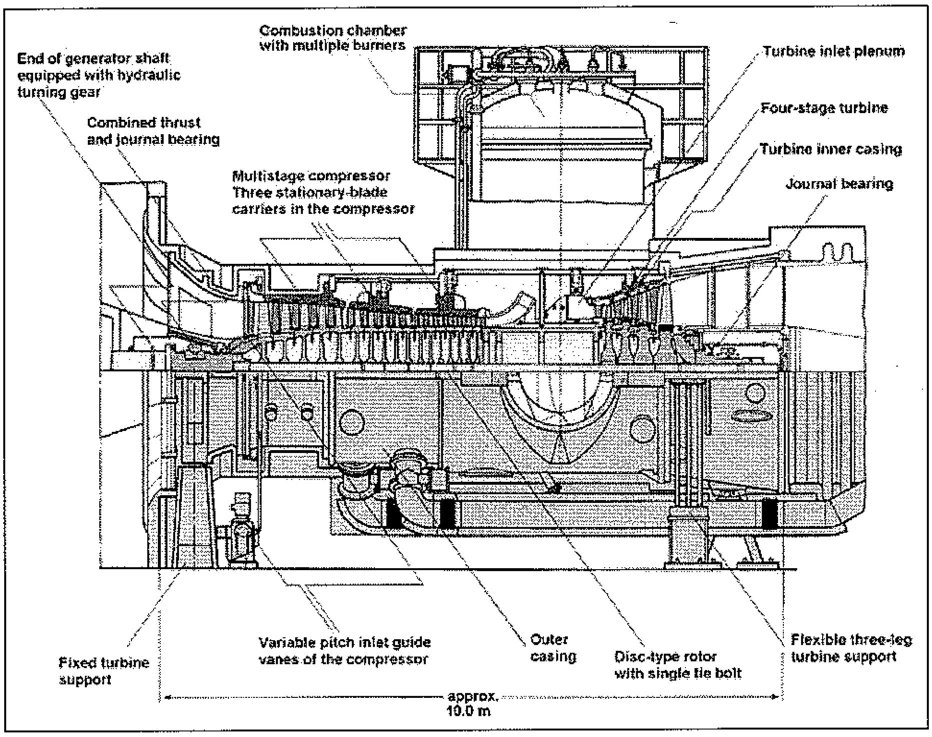


Figure 7.4: Gas turbine (159 MW) with a silo combustion chamber
[104, Siemens, 2001]

A gas turbine consists basically of three elements: a compressor, a combustion chamber and an expansion turbine (Figure 7.4). Ambient air is taken in by the compressor through the air intake system, filtered and then compressed to a pressure of between 10 and 30 bar in aeroderivative or larger industrial gas turbines. Since a gas turbine consumes large amounts of combustion air, the presence of even low concentrations of contaminants in the air can result in a significant fouling of the gas turbine. This can be due to some of the contaminants precipitating on the blades of the compressor, directly affecting the performance of the gas turbine. This effect can be seen in the photographs below, which show the first row of turbine vanes before and after turbine washing [164, Lenk and Voigtländer, 2001].

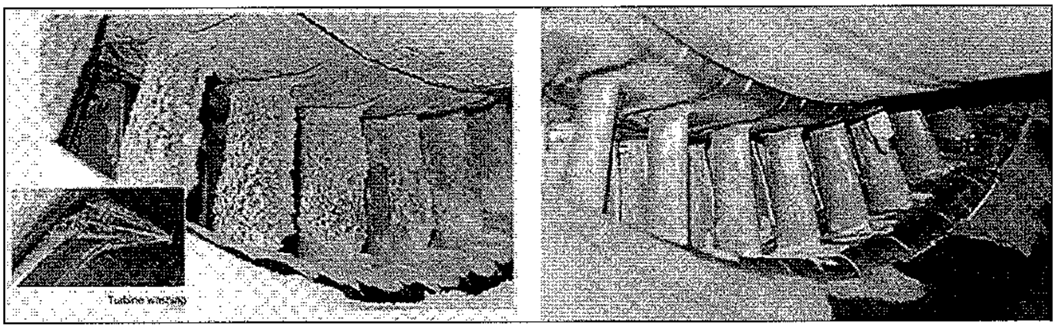


Figure 7.5: First row of turbine vanes before and after turbine washing [164, Lenk and Voigtländer, 2001]

The combustion air is filtered to prevent occurrence of these phenomena. In the combustion chamber(s), fuel and compressed air are burned at temperatures of up to 1235 to 1430 °C (for large gas turbines). After the combustion process, the gas expands through the turbine and generates electric power in the generator, drawing off the power needed to drive the compressors (Figure 7.3).

Gas turbines are designed with one or two shafts. Single-shaft gas turbines are configured with one continuous shaft and, therefore, all stages operate at the same speed. These units are most suited to generator drive applications where a significant speed variation is not required or even not wanted. In some cases, a reduction gear is applied between the gas turbine and the generator.

In a two-shaft gas turbine, the low pressure part of the turbine (the power turbine) is separated from the high pressure part, which drives the compressor. The low pressure turbine is able to operate at a wide range of speeds, which makes it ideally suited to variable speed applications. However, this feature is less important for application in power plants, because the driven equipment (i.e. the generator) has a constant speed during normal operation, related to the grid frequency.

In most heavy duty turbines for land-based operation, proven technology is used from aircraft or steam turbine applications. The materials applied in stationary gas turbines can be classified into three main groups: stainless steels (iron-based), nickel based alloys and cobalt based alloys. In general, the materials adopted for compressors are the same as those applied in the high pressure parts of the steam turbines. Nickel based materials are usually applied for combustor parts. For gas turbine blades, nickel based superalloys are applied because of their good mechanical properties at high temperatures.

As a result of optimising the superalloys with respect to mechanical properties, the corrosion resistance of these alloys is not optimal, especially at higher temperatures. Coatings are applied to improve the corrosion and oxidation resistance of turbine blade materials. Coatings for compressor blades are applied to improve the corrosion resistance (at low temperatures, condensates of moisture and acid solutions are corrosive to the components).

7.1.3 Compression ignition engines

Gas-fired compression ignition engines with a thermal input above 50 MW are rarely applied and thus described only briefly in this document. In the 1960s and 1970s, engine-driven power plants were mostly used for short-time running applications such as emergency, peaking and small-scale power production. Both larger base load engine driven power plants with outputs up to 150 MW_e and decentralised smaller simultaneous heat and power (CHP) production plants exist today. The reason for this trend is the opening-up, privatisation and decentralisation of the electricity markets in many countries, combined with the development, in recent decades, of high efficiency medium speed engines suitable for base load operation. Medium speed diesel engine units with a fuel input of up to 50 MW_{th}
'low pressure(dual fuel)' types) with a fuel input of up to 40 MW_{th} and spark-ignited engines with a fuel input of up to 18 MW_{th} are on the market [63, Wärtsilä, 2000].

7.1.3.1 Spark-ignited engines

A spark-ignited gas-Otto engine often works according to the lean burn concept. The expression 'lean burn' describes the ratio of combustion air and fuel in the cylinder, which is a lean mixture, i.e. there is more air present in the cylinder than needed for combustion. In order to stabilise the ignition and combustion of the lean mixture, in larger engine types, a pre-chamber with a richer air/fuel mixture is used. The ignition is initiated with a spark plug located in the pre-chamber, resulting in a high energy ignition source for the main fuel charge in the cylinder. The burning mixture of fuel and air expands, pushing the piston. Finally, the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of the fuel is transferred to the engine flywheel via the moving piston. An alternator is connected to the rotating engine flywheel and produces electricity. The engine type is designed for use with low pressure gas as a fuel.

7.1.3.2 Dual fuel engines

The dual fuel engine is a new engine type on the market developed for countries where natural gas is available. The engine type is fuel versatile, it can be run on low pressure natural gas or liquid fuels such as diesel oil, heavy oil, bio oils, etc. and it can operate at full load in both fuel modes. In the gas mode, the engine is operated according to the lean-burn principle, i.e. there is about twice as much air in the cylinder compared to the minimum needed for complete combustion of gas. This allows a controlled combustion and a high specific cylinder output without immediate risk of knocking or self-ignition when the process is well controlled. In gas engines, the compression of the air/gas mixture with the piston does not heat the gas enough to start the combustion process, some additional energy therefore, needs to be added and this is arranged by injecting a small pilot fuel stream (diesel oil, etc.). A liquid fuel such as diesel oil, etc. has a lower self-ignition temperature than gas and the heat in the cylinder close to the top position is enough to ignite the liquid fuel which, in turn creates enough heat to cause the air/gas mixture to burn. The amount of pilot fuel ranges from 1 to 5% of the total fuel consumption at full load. The engine works according to the diesel process in liquid fuel mode and otto-principle in gas mode. The burning mixture of fuel and air expands, which pushes the piston. Finally the products of combustion are removed from the cylinder, completing the cycle. The energy released from the combustion of fuel is transferred to the engine flywheel via the moving piston. An alternator is connected to the rotating engine flywheel and produces electricity.

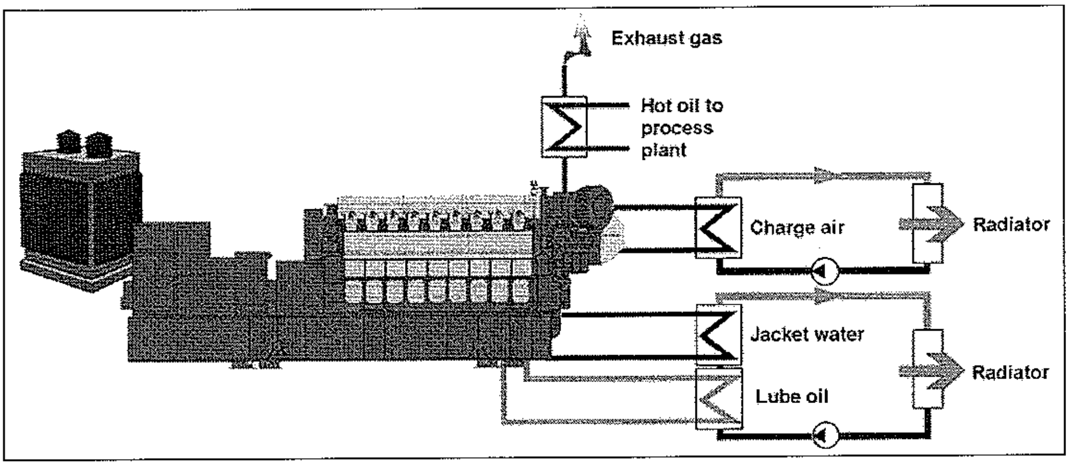


Figure 7.6: Natural gas fired engine
[149, Wärtsilä NSD, 2001]

7.1.3.3 High pressure gas injection engines

High pressure gas injection engines are operating according to the diesel process in both liquid and gas fuel modes. In gas mode, a pilot fuel oil (HFO, etc.) (typically 3 – 5 % of the total fuel

operate at full load both in liquid and gas fuel modes. High pressure gas diesel engines up to about 40 MW_{th} or 20 MW_e are available on the market.

7.1.3.4 Co-generation using gas engines

A common heat recovery application for combined heat and power plants with gas engines, is to generate low pressure steam for industrial purposes. The pressure range is usually from 3 to 16 bar, but higher steam pressure and extended steam production can be achieved with supplementary firing or auxiliary fired boilers. Steam at 8 bar is well suited for desalination and absorption chillers, while certain industrial processes might require higher steam pressures. The ratio between electricity and heat consumption very much depends on the application of the particular industrial facility. A typical CHP plant generating steam at 7 to 8 bar, typically has a total fuel utilisation of about 60 – 70 % when only steam is produced and up to 90 % for hot water generation. The total efficiency depends on the amount of heat of the engine cooling water circuit that can be recovered. The steam generation system has an auxiliary oil or gas fired boiler in parallel with the engine exhaust gas boiler and is flexible in applications where large amounts of low steam pressures are required. The heat in the engine exhaust gas can also be

burning air, etc. purposes dependent on the industry process requirements.

The second solution for boosting the steam generating capacity is to equip the exhaust gas boiler with supplementary firing. For larger spark-ignited gas engines, the oxygen content is typically 11 to 12 vol-% and for a high pressure gas diesel engine, often higher. This oxygen can be used as the main combustion air for supplementary firing. The system also makes it possible to generate high pressure steam and it has a good thermal efficiency for the additional fuel for the supplementary firing. So far, there are only a few reciprocating engines which exist equipped with supplementary firing, due to the challenges of combining the combustion flame with the pulsing of the engine exhaust gas and the relatively low oxygen content of the flue-gas [63, Wärtsilä, 2000].

An interesting CHP concept is the feed-water combined cycle where the waste heat from the engine exhaust gas and cooling circuits are used for increasing the efficiency of an existing, e.g. steam boiler plant. The electrical efficiency of a gas engine plant can be raised by equipping the plant with a steam turbine. Steam turbines most used in this application are single stage condensing turbines and the steam pressure typically applied is 12 to 20 bar.

7.1.4 Gas-fired boilers and heaters

Power plant gas-fired boilers are similar to the oil boilers described in Chapter 6. When designed for gas burning only, the combustion chamber is slightly smaller but, in most cases, these boilers are designed for burning liquid fuel too, in emergency situations or for co-combustion. The heat from the combusted fuel is used for the production of superheated steam, which expands in a steam turbine that drives a generator. In order to efficiently convert the energy from the steam to electricity, modern gas-fired boilers use supercritical steam parameters, which produces plant efficiencies of up to 48 % in the condensing mode and fuel utilisation figures of 93 % at combined heat and power production. The application of double reheat and increase of the supercritical steam parameters to 290 bar and 580 °C can reach these high efficiencies.

Another use of gas-fired boilers is as auxiliary boilers, to provide start-up facilities, including cold start possibilities in different types of thermal power plants. Auxiliary boilers are also applied in most power stations for heating buildings and equipment during standstill periods. These boilers are designed to produce slightly superheated steam at relatively low pressure. These small boilers are not addressed in this document.

There are a lot of gas-fired boiler installations in process industries and in district heating systems. Most of them are medium sized installations (i.e. from 50 to 300 MW). For these levels of heat output, increasing constraints on SO_2 and NO_X emissions leads to a larger utilisation of naturel gas. A large part of these boilers could also be fed with liquid fuel in emergency situations and for co-combustion.

The burners of the boilers are, in general, arranged in several levels in the walls (front firing or opposed firing) or at several levels tangentially in the four corners of the boiler. Firing systems for gas-fired boilers are similar to coal- or oil-fired boilers.

Gas burners are also used in process heaters, which are sometimes referred to as process furnaces or direct-fired heaters. These are heat transfer units designed to heat petroleum products, chemicals, and other liquids and gases flowing through tubes. The liquids or gases flow through an array of tubes located inside a furnace or heater. The tubes are heated by direct-fired burners that use standard specified fuels such as HFO, LFO, and natural gas, or the by-products from plant processes, although these can vary widely in composition. Gaseous fuels are commonly used in most industrial heating applications in the US. In Europe, natural gases also commonly used along with LFO. In Asia and South America, HFO are generally preferred, although the use of gaseous fuels is on the increase. More detailed information on gas and liquid fuel-fired heaters is available in Sections 6.1.4 and 6.1.10.2.

Gaseous fuels are used as support or start-up fuel for coal-, lignite- or oil-fired boilers. These combustion techniques are described in Chapters 4 and 6.

7.1.5 Combined cycle combustion

Today, about half of the new power generation capacity ordered consists of combined cycle power plants. At these plants, a gas turbine is combined with a steam turbine to generate electricity. For technical and cost reasons, the only practicable combined cycle gas turbine (CCGT) fuels are natural gas and light fuel oil (as back-up fuel). Figure 7.7 shows a three-dimensional drawing of a gas turbine combined cycle power plant built in Finland.

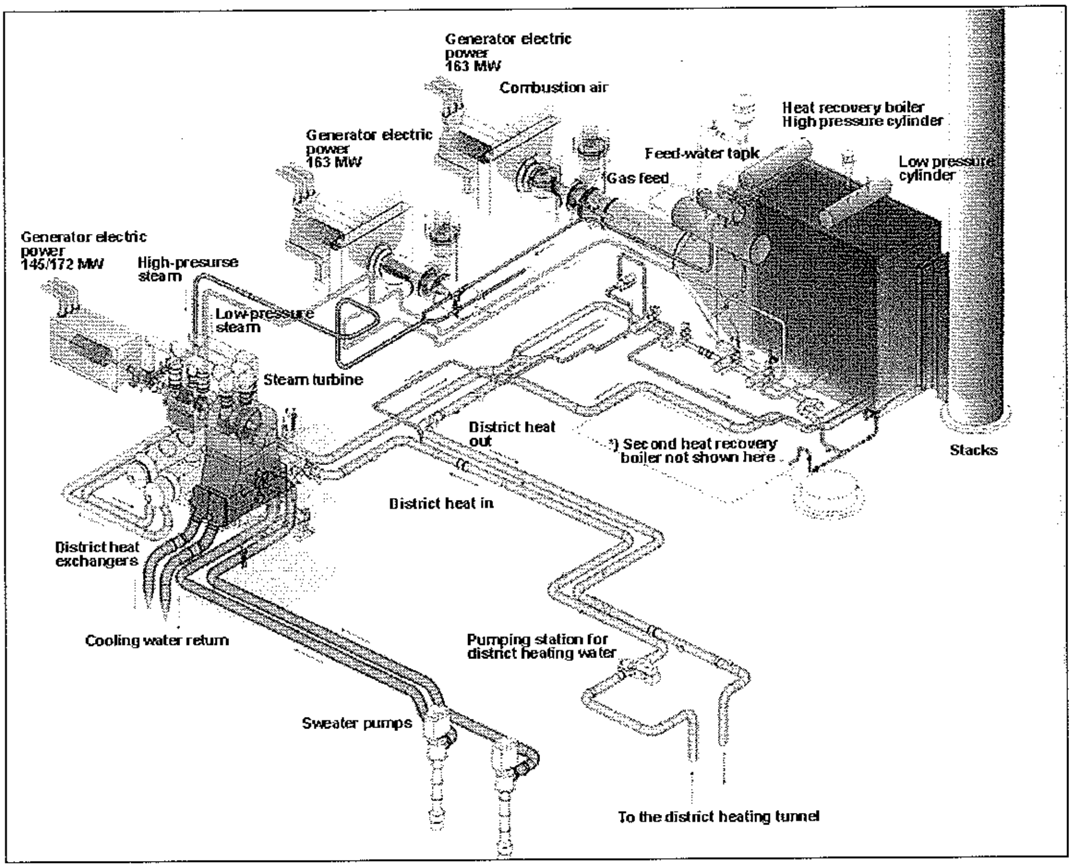


Figure 7.7: Gas turbine combined cycle power plant
[96, Helsinki Energy, 2001]

At combined cycle power plants, gas turbines generate power at an efficiency of approx.

on the turbine type and on ambient conditions. This hot gas is led to a heat recovery steam generator (HRSG), where it is used to generate steam, which then expands at a steam turbine power plant in principle similar to a condensing power plant. The great attractions of a CCGT plant are its low heat rate and its low investment cost, which have made CCGT competitive, despite the high cost of the natural gas fuel. In the past 20 years, the heat rate of a CCGT plant has decreased from 2.2 to 1.7, i.e. the LHV efficiency has grown from 45 to 58 %. Gas turbines are currently still undergoing rapid development, and a CCGT heat rate below 1.67 (efficiency

the output comes from the gas turbine and the remaining 1/3 from the steam turbine. However, recent commissioning experience suggests that there are difficulties in achieving the very high efficiencies forecast.

Because less than 1/3 of the oxygen in the gas turbine inlet air is consumed for combustion in the gas turbine combustor, supplementary firing of fuel in the gas turbine exhaust gas is possible. In modern CCGTs, this causes a slight increase in the power generation heat rate. However, in industrial co-generation, it is frequently used as a means of controlling HRSG steam generation independently of the gas turbine output. In co-generation applications, supplementary firing also improves the overall efficiency of heat and power generation.

Because both natural gas and light fuel oil are very clean fuels and allow a practically complete combustion in gas turbine combustors, there are no problems with ash, char or SO_2 at CCGT plants. The only problem is NO_X, which, at modern plants, is controlled by using special low NO_X burners and sometimes SCR added to the HRSG. In older burners, the NO_X can be controlled by water or steam sprays into the burners, but it happens at the expense of the plant heat rate.

Gas turbines are inherently very noisy, therefore they are built into special noise attenuation enclosures, with silencers integrated into the gas turbine air intake and exhaust gas outlet channels.

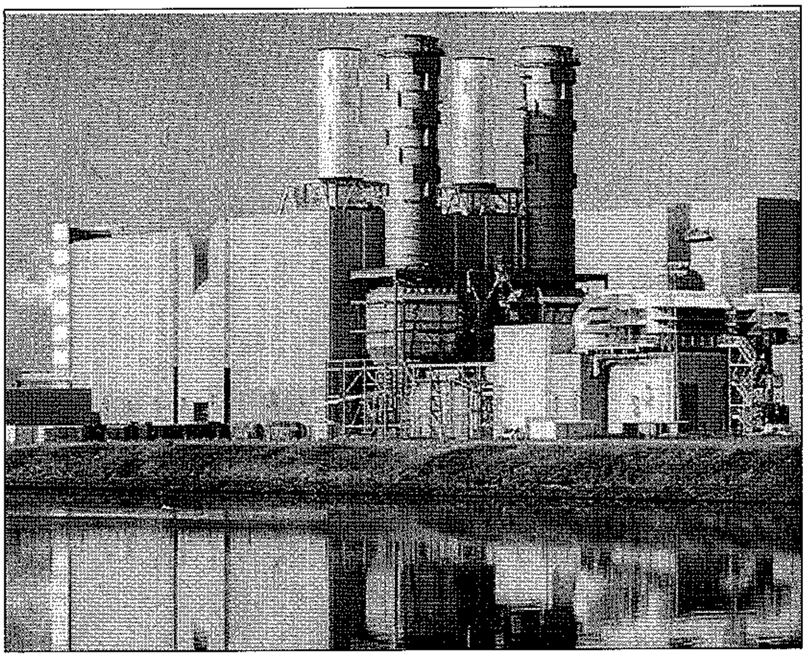


Figure 7.8: Recently built gas turbine combined cycle power plant in Belgium

In the power generation sector, several gas turbine process configurations can be distinguished for the use of the energy contained in the gas turbine off-gas:

- combined cycle without supplementary firing (HRSG)
- topping cycle (hot wind box).

7.1.5.1 Combined cycle without and with supplementary firing (HRSG)

Within this process, fuel is exclusively fed into the combustion chamber and no additional firing takes place in the recovery steam generator. The steam generated by the heat recovery steam generator from the thermal energy contained in the gas turbine exhaust gas is further used to produce electricity via a steam turbine. This type of combined cycle gas turbine achieves efficiencies as high as 58.5 %. The fuel generally used is natural gas or light oil, but the use of coal in a gasification plant, that will need to be installed upstream of the gas turbine, is also possible (see Chapter 4). A schematic drawing of the combined cycle without supplementary firing (HRSG) technology is given in Figure 7.9.

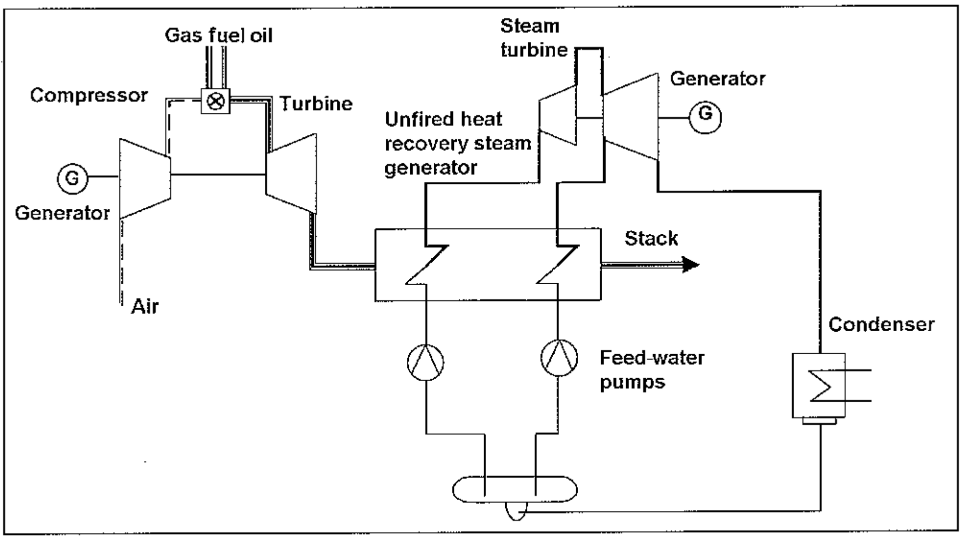


Figure 7.9: Schematic of a combined cycle power plant with a heat recovery steam generator (HRSG)
[32, Rentz, et al., 1999]

A multishaft configuration is applied mostly in phased installations in which the gas turbines are installed and operated prior to the steam cycle operation and where the intention is to operate the gas turbines independently of the steam system. Multishaft combined cycle systems have one or more gas turbine generators and HRSGs that supply steam through a common header to a separate single steam turbine generator unit.

Exhaust gas bypass systems, which are applied in multishaft combined cycle systems to provide fast start-up and shutdown and flexibility of operation are not required with singleshaft systems or with multishaft systems with one gas turbine and one steam turbine

HRSGs are generally heat-exchangers of the convection type, provided with fin tubes, and which exchange the heat from the exhaust gases to the water steam cycle. The exhaust gases are cooled down as low as possible to achieve the highest efficiency. The temperature is restricted by the risk of corrosion caused by a possible condensation of the acid (sulphur) products from the exhaust gases. Exhaust temperatures of 100 °C are considered normal.

HRSGs are constructed in horizontal (with natural circulation of the evaporation system) and vertical (with forced circulation of the evaporation system) configurations. The choice depends on the space requirements and/or the client preferences. Both types are widely used.

7.1.5.1.1 Combined cycle with supplementary firing (topping cycle)

In a topping cycle, the heat of the exhaust gases of the gas turbine is used as combustion air in a conventional power plant with coal or gas fired steam boilers. Several options for integrating this cycle with a conventional power plant process are possible. Although this integration is feasible in new designs, topping cycles have typically been applied in the past as repowering options to improve the efficiency of existing plants (see example 6.2.3.1 in Chapter 6) and/or to increase the heat supply capability of co-generation plants. Various types of topping cycle combined gas turbines are in use in application with outputs of up to 765 MW_e (1600 MW_{th}), and can achieve efficiencies of up to 48 %. A schematic drawing of this technology is shown in Figure 7.10.

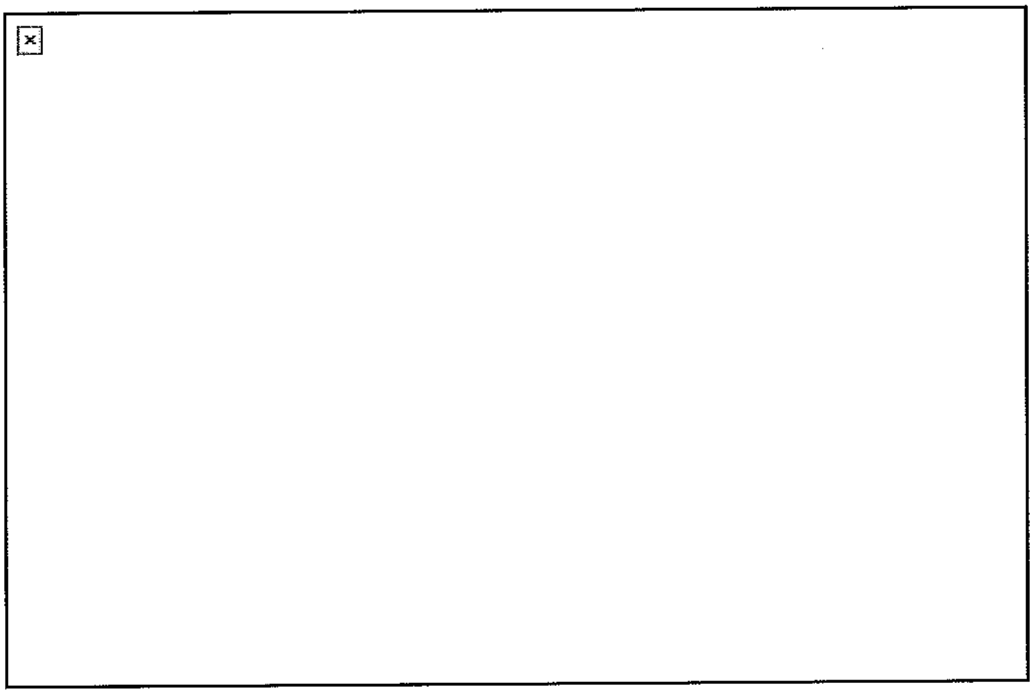


Figure 7.10: Schematic of a topping cycle combined power plant
[32, Rentz, et al., 1999]

In a topping cycle (combined cycle with supplementary firing), the air preheaters that heated the inlet air are not needed and should be removed. A gas turbine is usually selected with approximately the same exhaust gas flow as the design combustion airflow of the boiler. Because of the lower oxygen content of the exhaust gases of the gas turbine (in comparison to normal combustion air), less fuel can be combusted in the existing boiler. This results in a lower average temperature of the boiler and consequently a lower steam production in the boiler. The temperature of the flue-gas at the outlet of the radiation part of the boiler will be about the same as in the existing situation. This results in excess heat at lower temperatures. To use this excess heat, a high pressure and a low pressure economiser have to be installed in the boiler. In these economisers (parallel to the existing feed-water preheaters) part of the feed-water will be preheated and, therefore, the amount of extraction steam from the steam turbine will decrease.

A two-stage combustion process can also be created by using exhaust gases of the gas turbine in the existing boiler and resulting in a considerable reduction of NO_X emissions. In one case example, a reduction of NO_X emissions of 50 % has been achieved in the Netherlands.

The electrical capacity of the gas turbine is 20 – 25 % of the total capacity of the power plant.

7.1.5.1.2 Topping cycle with feed-water heating

This process configuration is a combination of the two combined cycles mentioned above. Here, part of the condensate and of the feed-water is preheated in the heat recovery steam generator. The gas turbine or reciprocating engine heat recovery steam generator is linked to the steam turbine/steam generator but only on the water/steam side; a replacement of the combustion air by the gas turbine or reciprocating engine exhaust gas does not, therefore, take place. Reciprocating engines are suited for low pressure feed-water preheating.

By using feed-water heating, the prime mover (gas turbine or reciprocating engine) exhaust gases are cooled in the heat-exchangers by preheating the feed-water. In general, two heat-exchangers, (or strings) one each for low pressure and high pressure feed-water heating, are installed. The heat-exchangers are equipped parallel to the existing (steam fed) feed-water preheaters.

Heat extractions from the prime mover can be eliminated or reduced, which thus results in an increase in the electrical power output of the prime mover. This implies that the heat in the exhaust gases of the prime mover contributes fully to the electrical power output and efficiency of the unit. It appears that the best solution with feed-water heating will be obtained with prime mover with a high efficiency and enough heat capacity to achieve the complete feed-water heating of the bottoming cycle.

The increase in power production is, however, limited by the flow capacity of the steam turbine and by the power rating of the generator. The efficiency improvement with this option is about 2 5 % dependent on the prime mover and the existing steam turbine capacity.

A comparison of the capacity of the preheating system of the unit with the heat available in the gas turbine exhaust gases sets the number of prime movers required and the ultimate increase in heat capacity.

The increased flexibility (electrical power versus thermal heat production) is an important advantage gained by the modifications described. The steam plant can operate independently of the prime mover. The flexibility, however, is limited by the maximum allowable flow through the low pressure steam turbine.

Because a topping cycle with feed-water heating does not affect the combustion process of the boiler, the boiler emissions are also unaffected. Total emissions are influenced by the contribution of the prime mover exhaust gases.

7.1.6 Co-generation (CHP)

converted into electric power at electricity-only power plants. The rest is lost as low temperature waste heat into the air or water or both. Because a lot of heat is also needed by the end users in space heating and many industrial processes, the question arises as to how this rejected heat of condensing power plants can be made useful. The thermodynamic answer to this is quite simple: raise the temperature of the rejected heat to the useful level required, e.g. to 70 – 120 °C for °C for industrial processes. However, this happens to the cost of power generation.

Co-generation is a means of improving the energy efficiency by influencing the energy supply system structure. In every case, co-generation can save fuel compared to the separate generation of heat and power from fossil fuels. If the local heat load is big enough, and the co-generation plant consequently big enough, co-generation can also save money. Technically, all power plants can be modified for co-generation. The suitability of applying a gas turbine in a co-generation plant is partly related to the relatively low investment costs and the high cycle efficiency it offers.

The heat from the gas turbine exhaust gases is used for steam production in a heat recovery steam generator (also called a waste heat boiler). The steam can be used fully for electricity production, as in the combined cycle, or can be extracted partially (or sometimes fully) and used for steam supply to consumers, who can then use the steam in their own processes or for other purposes such as district heating or seawater desalination.

There are many possible configurations to meet the specific plant requirements. Depending on the demand for heat and power, the most common are:

- gas turbine with a heat recovery steam generator and supply of all the generated steam to steam consumers
- gas turbine with a heat recovery steam generator with back-pressure steam turbine, and supply of all the generated heat to steam consumers
- gas turbine with a heat recovery steam generator with steam extractions to consumers and/or the use of extraction steam for other heating purposes and a vacuum steam condenser. This design usually gives more flexibility in the power/heat ratio
- steam injected gas (STIG) cycles in which steam is also generated by the exhaust heat but partly injected to the gas turbine. These are used primarily with aeroderivative gas turbines without the application of a steam turbine. These cycles are mainly applied in co-generation applications with intermittent process steam demands.

An important measure of a co-generation power plant is its power/heat output ratio. Obviously, because electric power can be economically two to four times as valuable as heat, it can be preferable to have as high a power/heat ratio as possible in combination with a low overall heat rate. Here again, the laws of physics set their limits. As explained above, the higher the temperature level of the recovered heat, the less power and more heat is gained from the process. In case a high power/heat ratio is requested or required in this respect, the combined cycle (CCGT) is far more favourable than the conventional steam process. At a condensing CCGT, 2/3 of the power output comes from the gas turbine, and the co-generation-related power loss only occurs in the steam turbine producing the other 1/3 of the output. The power/heat output ratio of a CCGT at nominal load can be 1.1 in district heating applications and 0.9 in the pulp and paper industry, while the figures in steam only co-generation are 0.6 and 0.3 respectively. The annual average figures are typically clearly lower, due to, among others, part load operation and start-up/shutdown cycles.

For co-generation to compete successfully in the market, a high price and demand of electricity and a big enough local heat demand are determining parameters required. For a small power and heat demand, the plant size may remain under the limit of economic competitiveness.

	Power generation heat rate (1)	**Power to heat ratio (2)**	**Total co-generation system heat rate (3)**	**Separated system heat rate; coal (4)**	**Separated system heat rate; CCGT (5)**
Conventional coal condensing	2.3				
CCGT condensing	1.8				
Industrial conventional co-generation (6)	5.0	0.28	1.1	1.36	1.25
Industrial CCGT co-generation	2.4	0.9	1.15	1.67	1.43
DH conventional co-generation	2.9	0.6	1.1	1.55	1.36
DH CCGT co-generation	2.1	1.1	1.1	1.73	1.47
Heat only boilers/coal			1.1		
Heat only boilers/HFO			1.1		
Heat only boilers/gas			1.07		

Notes:
1) Fuel input (LHV)/Net power output
2) Net heat output/Net power output
3) Fuel input (LHV)/(Net power + heat output)
4) Combined heat rate of producing separately in conventional coal condensing plants and heat only boilers (HR = 1.1) the same amounts of power and heat as in the cogenerating system. To be compared with the HR indicated in row 3
5) Combined heat rate of producing separately in CCGT condensing plants and heat only boilers (HR = 1.1) the same amounts of power and heat as in the cogenerating system. To be compared with the HR indicated in row 3
6) Live steam 80 bar 480 °C; back-pressure 4 bar

All figures refer to nominal full load operation.

Table 7.1: Indicative comparison of co-generation with separate power and heat generation [59, Finnish LCP WG, 2000]

In Table 7.1, the total system heat rates (the final three columns on the right) are comparable in each row. They tell how much fuel is needed in a co-generation system and in a separated system with the same power and heat outputs, but with heat and power generated separately. It can be seen that, in each case, the separated system – whether conventional or CCGT-based – clearly consumes more fuel than the co-generation system providing the same energy service. When the comparison basis is conventional condensing power, the reduction in fuel consumption by co-generation ranges from 20 % for the conventional industrial co-generation to 57 % for the district heating CCGT co-generation. If CCGT condensing is assumed for the separate power generation, the savings are smaller, 12 % and 34 % respectively. These figures are quoted only to give a general idea of fuel savings through co-generation; the actual figures always depend on the specifics of each project and the energy supply system of which it is a part.

For co-generation to compete successfully in the market, a high electricity price and a big enough local heat demand are required. For a small heat demand, the plant size remains under the limit of economic competitiveness. Big local industrial heat loads typically exist in the pulp and paper industry, in refineries and in the chemical industry and, in some cases, in the food and textile industries. See also Section 7.1.3.4 'co-generation using gas engines' for reciprocating engine information.

Cheng cycle

generation on one pressure level, which is fully injected into the gas turbine. In practice, the Cheng cycle is applied in combined heat and power (CHP) units giving a normal steam supply to users, with a varying heat demand. In situations where no heat or less heat is required the generated steam can be used for electric power generation. It can be noted that make-up water is required for the steam generation, which has to be considered as an overall loss due to its discharge to air together with the exhaust gases. The efficiency increases with decreasing compressor ratio. A turbine efficiency of more than 50 % at a turbine inlet temperature of 1200 °C is calculated [58, Eurelectric, 2001].

7.1.7 Control of emissions to air from gas-fired turbines and combined cycles

7.1.7.1 Abatement of dust emissions

Fuel dust contained in natural gas is washed out at the production site if necessary. Dust or particulate matter emissions from gas turbines burning natural gas are not an environmental concern under normal operation and controlled combustion conditions.

Other gases, such as the by-products of chemical plants, can contain dust. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with primary and secondary measures to reduce the dust emissions if these limits cannot be met.

7.1.7.2 Abatement of SO_2 emissions

Fuel sulphur in natural gas in the form of H_2S is washed out at the production site. Thus, fuel qualities are obtained which directly meet SO_2 emission limit values for all applications. Other gases, e.g. as by-products of chemical plants, can contain sulphur. These gases are required to meet different emission limit values compared to natural gas and must be burned or co-combusted in power plants equipped with FGD technology if these limits cannot be met.

7.1.7.3 Abatement of NO_X emissions

7.1.7.3.1 Water or steam injection

Since dry low NO_X combustors (DLN) have reached an acceptable state of development, water/steam injection is now used in Europe, although only to a minor degree so far, as a NO_X reduction measure. However, for existing installations, it is the most easily applicable technology, and may be applied in combination with other NO_X abatement measures. In Canada, about half of the gas turbines with NO_X control are equipped with steam/water injection.

Water/steam injection can be performed either by the injection of a mixture of fuel and water or steam or by the injection of water or steam through nozzles directly into the combustion chamber. The evaporation or superheating of steam requires thermal energy, which is then not available to heat the flame. Thus, the flame temperature decreases and NO_X formation also reduces. As can be seen from Figure 7.11, the emission reduction rate strongly depends on the amount of water or steam used. In order to reach high emission reduction rates, large amounts of water or steam are necessary; sometimes the amount of water or steam injected is higher than the amount of fuel burned. A higher emission reduction rate can be achieved with water than with steam (for a given water or steam-to-fuel ratio), which can be explained by the fact that more energy is required to evaporate the water (in practice approximately twice as much steam is necessary to achieve the same NO_X emission reduction). Water injection is often used when steam is not available, e.g. in simple cycle applications and in pipeline compression, whereas steam injection is usually preferred on natural gas-fired combined cycles, where steam is readily available from the exhaust heat recovery system.

The steam, or water, injected into gas turbines needs to be of very high purity, which requires the use of a high quality water treatment plant, which in turn may create a liquid effluent requiring disposal. Also, the steam or water needs to be injected at high pressures, usually 20 bar or greater. The use of steam or water injection may also reduce the life expectancy of a gas turbine.

Emission reduction rates of between 60 and 80 % can be achieved but without limiting CO. If CO emission limit values are observed, NO_X reduction rates between 40 and 60 % can be achieved. The steam/water to fuel ratio depends on the gas turbine type (e.g. for flame) and it varies between 1 and 1.2. NO_X ^{3} (at 15 % O_2). The reduction rates by steam or water injection are presented in Figure 7.11.

The injection of water or steam has an influence on the general gas turbine parameters, such as the output, efficiency, and the exhaust mass flow. For example: the efficiency of a gas turbine is reduced through water/steam injection, and flame stability problems can be observed at high water to fuel ratios [32, Rentz, et al., 1999].

The investment costs for retrofitting gas turbines with water or steam injection can vary widely. These costs are mainly related to the water conditioning and injection devices used. The additional operating costs incurred by the water/steam injection are due to an increased fuel consumption.

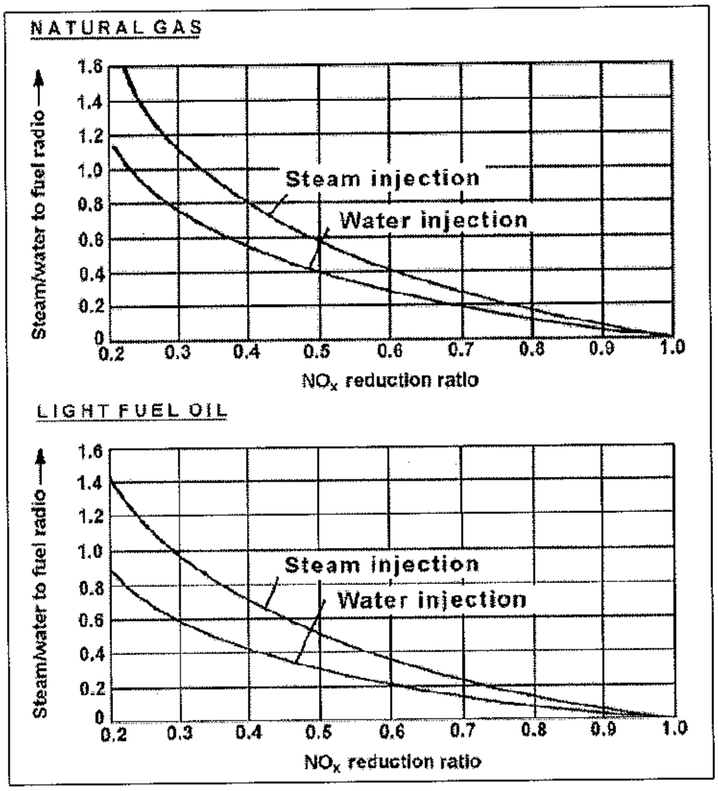


Figure 7.11: NO_X reduction by steam or water injection
[32, Rentz, et al., 1999]

Some major drawbacks of this NO_X abatement technique are the increased emissions of CO and hydrocarbons, a decrease in the thermal efficiency of the installation, and an increase in fuel consumption. Steam injection causes a greater efficiency loss than water injection (3 – 4 % for water injection). Furthermore, direct injection of water or steam results in a higher material stress (small fissures can occur on the material surface due to temperature shock) than injection of a fuel/water or steam mixture. As a consequence, the latter alternative is preferred. [32, Rentz, et al., 1999].

The emission levels can vary a lot, depending on the load of the turbine. In many installations, the steam can be produced only in higher loads, which means that emissions will be reduced only after this base load level has been reached. This makes steam injection of little use for gas turbines with lots of load changes. A steam injection retrofit for a 140 MW_{th} gas turbine costs about EUR 1.7 million.

The injection of water or steam to reduce NO_X can only be carried out to a certain limit. If the steam flowrate injected in the fuel burner is too high (typically the gas turbine supplier fix a limit on steamflowrate/fuel gas flowrate = 1.2), the effects on the compressor are relevant. The amount of steam (or water) can also be responsible for trouble in the combustion chamber (burners, flow sleeves, liners, transition pieces) with particular effect on lifetime and risks of failure with damages to the downstream turbine section. In addition, the increase of water concentration in the exhaust flow from the combustion chamber to the turbine section has an impact on the integrity of blades and nozzles. In fact, the heat exchange coefficient from the exhaust flow to the surface of the nozzles or blades is proportional to the water concentration. So if the gas turbine runs with a large amount of steam or water in order to control the NO_X, mechanical damage and a efficiency reduction may occur, increasing the maintenance costs and the risk of failure.

The injection of water or steam requires a preparation of water used for the process. At sites where steam or water is not used a for other requirements, the investment and operation costs

250 MW thermal input, with changing operation conditions and with low operating hours per

turbines, the conversion of the burning system of a gas turbine to a steam or water injection system requires an amount of changes in the design and the layout of the gas turbine. This technology is not appropriate for the gas transmission system of Europe.

7.1.7.3.2 Dry low NO_X (DLN) technologies

Currently, dry low NO_X combustors are applied for large gas turbines, and seem to be becoming more widespread in small facilities (e.g. gas turbines with capacities even below 20 MW_e). DLN technology has also recently been applied to gas turbines operated offshore (see also Sections 7.1.12 and 7.5.5).

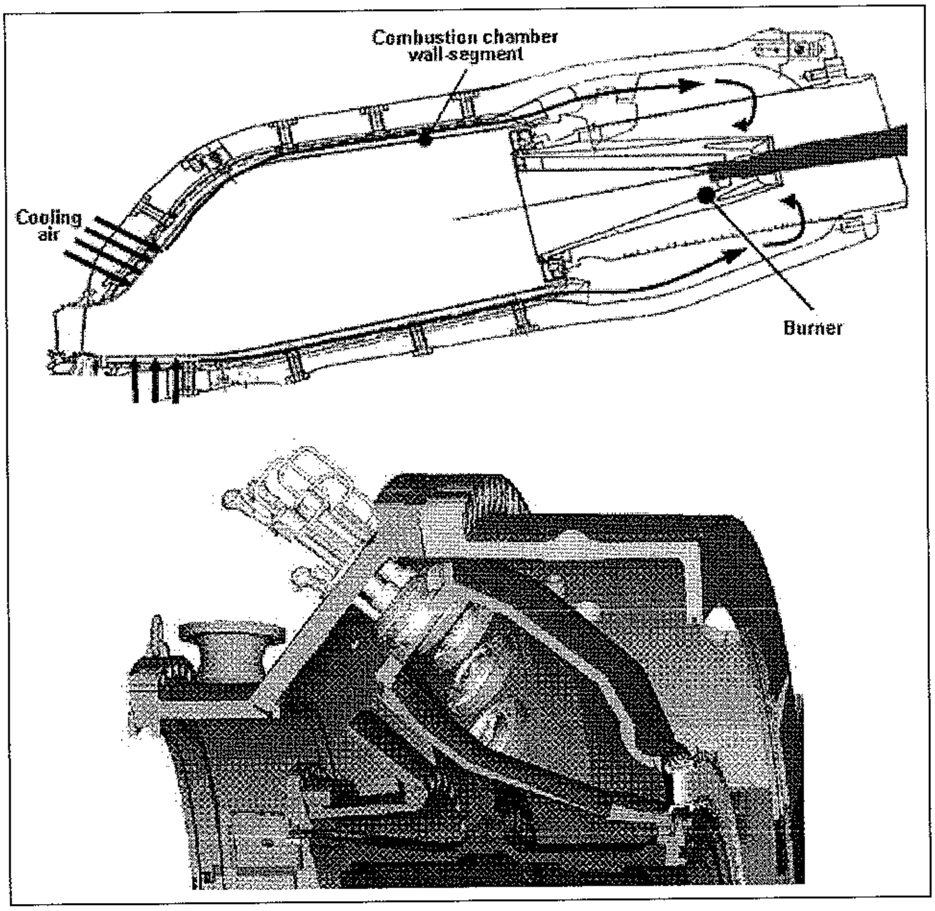


Figure 7.12: Schematic of a DLN combustion chamber

The basic characteristic of dry low NO_X combustors (e.g. Figure 7.12) is that the mixing of the air and fuel and the combustion both take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature are achieved, resulting in lower NO_X emissions. Currently, dry low NO_X combustors represent a well established technology, especially for gas turbines using natural gas. Further developments are necessary for gas turbines utilising fuel oils: as, in these turbine operations, not only does premixing of the air and fuel have to be carried out before combustion, but so does evaporation of the liquid fuel. As the particle size has an impact on the evaporation velocity, current research is focusing on developing more efficient atomiser systems. At a Swedish gas turbine power plant, hybrid burners have been operated on light fuel oil in premix mode for almost two years: a considerable NO_X reduction has been achieved, but achieved values are not as low as for the combustion of natural gas. DLN systems for dual fuel-fired (gas/gasoil) GTs are also under development. It is understood from one manufacturer that such dual fired DLN systems are now available and have been tested.

Dry low NO_X combustion systems are very effective and reliable. Today, almost all gas turbines in industrial use are equipped with dry low NO_X systems. Modern dry low NO_X burner retrofits cost approx. EUR 2 million for a 140 MW_{th} gas turbine. Due to their high efficiency, new burners are very economical to operate, especially as there are no great losses of energy from fuel losses, or in the form of hydrocarbons, etc. The investment costs are approx. 15 % higher and maintenance costs are about 40 % higher than non-DLE gas turbines. Dry low NO_X combustion is very model-specific, i.e. each manufacturer develops the technology for each model where there is enough demand to justify the research necessary to develop it. For older models or models with low demand for the technology, it may not be available. Also, earlier versions of the technology may have slightly higher NO_X levels than recently developed versions.

7.1.7.3.3 Selective catalytic reduction (SCR)

Many gas turbines currently use only primary measures to reduce NO_X emissions, but SCR systems have been installed at some gas turbines in Austria, Japan, the Netherlands and in the US (especially in California). It is estimated that approximately 300 gas turbines worldwide are equipped with SCR systems. Further applications of SCR technology at gas turbines are planned in Denmark and Italy [32, Rentz, et al., 1999]. Figure 7.13 and Figure 7.14 demonstrate how SCR catalysts are applied within the CCGT concept, first in a horizontal HRSG and secondly in an installation with a vertical flow set-up [161, Joisten, et al.,].

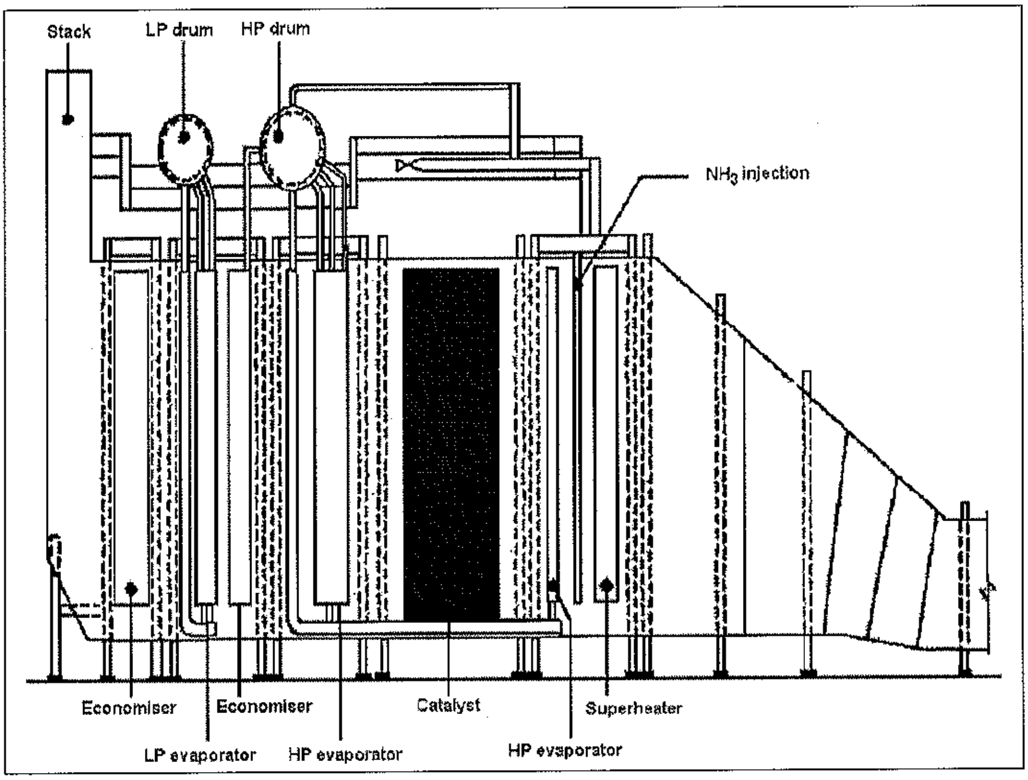


Figure 7.13: HRSG design and SCR installation
[161, Joisten, et al.,]

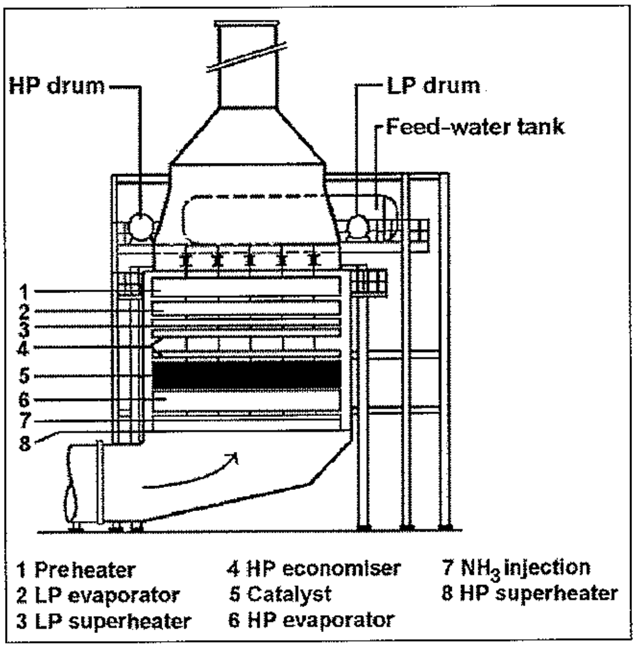


Figure 7.14: SCR installation with vertical flow
[161, Joisten, et al.,]

7.1.7.3.4 Comparison of 1993 and 1999 NO_X control costs for gas turbines

NO_X control technology	Turbine output (MW)	Emission reduction (ppm)	1993		1999	
			USD/tonne	USD cents/kWh	USD/tonne	USD cents/kWh
Water/steam injection	4 5	Uncontr. → 42				
		→ 42			[2]	n.a.
		→ 25	n.a.[2]			
Catalytic comb. [1]	4 5	Uncontr. → 3	n.a.	n.a.	1000	0.32
		→ 9	n.a.	n.a.	5900	1.06
Conventional SCR	4 5	42 → 9	9500 10900			
High temp. SCR	4 – 5	42 → 9	9500 10900			
$SCONO_x$	4 5	25 → 2	n.a.	n.a.	16300	0.85
Water/steam injection		→ 42				
		→ 25				
Catalytic comb. [1]		→ 3	n.a.[2]	n.a.	690	0.22
		→ 9	n.a.	n.a.	2200	0.43
Conventional SCR		→ 9	3800 10400			
		→ 9	3800 10400			
		→ 2	n.a.	n.a.	11500 [3]	0.46
Water/steam injection	160	Uncontr. → 42	480	0.15	480 [4]	0.15
DLN	170	Uncontr. → 25	n.a.[2]	n.a.	124	0.05
DLN	170	Uncontr. → 9	n.a.	n.a.	120	0.055
Catalytic comb. [1]	170	Uncontr. → 3	n.a.	n.a.	371	0.15
Conventional SCR	170	42 → 9	3600	0.23	1940	0.12
High temp. SCR	170	42 → 9	3600	0.232	2400	0.13
SCONOX		25 → 2	n.a.	n.a.	6900 [2]	0.29

Notes:

(1) Costs are estimated, based on Catalytica's 'Xonon™' catalytic combustor technology which entered commercial service in 1999. Annualised cost estimates provided by the manufacturer are not based on 'demonstrated in practice' installations.

(2) 'n.a' means technology that was not available in 1993, or technology that is obsolete in 1999.

(3) The SCONOX ™ manufacturer provided a quote for a 83 MW unit. The quote has been scaled to the appropriate unit size.

(4) The one baseload gas turbine installed in 1990 is the only baseload turbine that is equipped with steam injection. All subsequent baseload machines have been equipped with DLN. For this reason, the 1993 figures are assumed to be unchanged for steam injection.

Table 7.2: Comparison of 1993 and 1999 NO_X control costs for gas turbines (retrofitting costs are not considered)
[182, OSEC, 1999]

The costs listed in Table 7.2 are strongly dependent upon the specific boundary conditions of the gas turbine and a transfer to other plants may not be possible. The cost data are not applicable for offshore installations.

7.1.8 Control of NO_X emissions from spark-ignited (SG) and dual fuel (gas mode)

The most important parameter governing the rate of NO_X formation in internal combustion engines is the combustion temperature; the higher the temperature the higher the NO_X content of the exhaust gases. One method to reduce the combustion temperature is to lower the fuel/air ratio, the same specific heat quantity released by the combustion of the fuel is then used to heat up a larger mass of exhaust gases, resulting in a lower maximum combustion temperature. This primary measure called the lean-burn approach in reciprocating engines is analogous to dry low-NO_X combustors in gas turbines. Gas engine (SG and DF) installations have low NO_X levels due to the lean-burn approach. In some special applications (e.g. larger plants in non-attainment areas in the US), gas turbines are equipped with SCR for additional NO_X reduction.

Spark-ignited lean-burn (SG) and dual fuel (DF) engines in gas mode are often equipped with an oxidation catalyst mainly for CO removal. The NMVOC emission from spark-ignited lean-burn gas (SG) engines and dual fuel (DF) engines in gas mode depend on the natural gas composition. Depending on the legislation in force and the composition of the natural gas, NMVOC secondary emission reduction techniques might, in some cases, be needed and oxidation catalysts for simultaneous CO and NMVOC reduction are applied.

In the case of SCR, a urea solution is generally the reduction agent of choice for SCR systems applied to engines. For applications with varying loads, the engine emissions are measured at different load levels during commissioning. The measured emissions values are then entered into the system controls, which ensures that the reduction agent is injected into the exhaust gas stream in the correct quantities for varying NO_X levels. The catalyst type and the SCR reactor size are tailored to the pressure drop constraints of each particular application so that the engine performance is not affected by any changes [167, Rigby, et al., 2001].

7.1.9 Control of NO_X emissions from gas-fired boilers

The boilers and firing systems are in general designed for low NO_X firing. Basically there are three different ways to reduce NOx emissions:

- application of low NO_X burners. The conditions for low NO_X emissions is a low temperature in the primary combustion zone and a sufficient long retention time of the flue-gases in the furnace for a complete burnout. This will reduce the flame temperature
- Flue-gas recirculation is a method that can be effective if a large percentage of the emission is thermal NO_X. It reduces both the flame temperature and the concentration of oxygen as well
- two stage combustion reduces the reaction between oxygen and nitrogen in the air during the combustion process. Substantially low NO_X emissions can be achieved by supply of the air at three stages around the individual burner and supplementing air above the individual burners and a precise dosing of these air streams.

The NO_X emissions, which are standard for gas-fired boilers, are lower than 100 mg/Nm^3.

7.1.10 Water and waste water treatment

For the gas turbine and the HRSG, demineralised water is required for the following purposes:

- to compensate for the blowdown water from the drums for the HRSG. If steam or water injection is applied, the water loss also has to be compensated for by make-up water. The quality has to meet the requirements of the manufacturers and water treatment is, therefore, required. Demineralisation is usually sufficient to meet these requirements
- demineralised water is usually used for washing the gas turbine compressor. Condensate from the water/steam cycle is sometimes used for online washing, but usually demineralised water is supplied to a separate water wash unit. For offline washing, a detergent is added to the demineralised water to improve the washing effect.

Waste water from a gas turbine and an HRSG (if applied) includes:

- blowdown water from the boiler circulation system to maintain the quality of the boiler water. To protect the boiler from corrosion, the boiler water usually contains additives such as ammonia, sodium hydroxide and/or phosphates. In practice, this blowdown water is quenched and discharged to sewerage systems or to a water treatment plant if the water does not meet permit requirements
- waste water from the gas turbine water washing process can be discharged or may have to be considered as a chemical waste, depending on the detergents used for washing and the compressor materials to be disposed of
- water, which is contaminated with oil or with fluids containing oil, is usually collected into a collecting system and discharged separately to a treatment plant
- remaining waste water from the plant, such as scrubbing water, is normally discharged to the domestic sewerage system.

Further treatment of waste water from the gas turbine (and/or HRSG if applied) is necessary to meet the permit requirements for the discharging the waste water.

7.1.11 Control of noise emissions

The large equipment used in gas-fired power plants can give rise to emissions of noise, and/or noises due to vibrating machinery. In these cases, the noise emissions may be abated in the following way:

- by locating gas turbines, steam turbines and generators in enclosures
- by ventilating enclosures with low noise fans
- by adding cladding to the steam turbine support structure
- by fitting high level stack silencers
- by locating boiler feed pumps in enclosures
- by building a pump house around the pumps for circulating the cooling water
- by operating moderate noise fans in the cooling towers (it should be noted that the noise emissions from once-through cooling water systems are less than from cooling towers).

7.1.12 Offshore combustion installations

Oil and gas production facilities in the UK and Norwegian offshore sector, based on a steel or concrete support structure and topside modules containing oil and gas processing equipment, typically use gas turbines for power generation and possibly large pump and compressor drives, with reciprocating internal combustion engines ('diesels') for emergency generation and possibly for fire pump duty. Such combustion installations operated on offshore platforms in the North Sea, as covered by the IPPC Directive, i.e. of a rated thermal input exceeding 50 MW, namely gas turbines, operate a total number of about 270 turbines. These are turbines that are mostly fuelled by natural gas produced from the field under operation. Part of it is not suitable for further purposes and, therefore, has had to be flared or vented to theair. Therefore, it is not, or cannot be, fully processed and varies both in composition and calorific value, from field to field and, over time, even within a field [124, OGP, 2000].

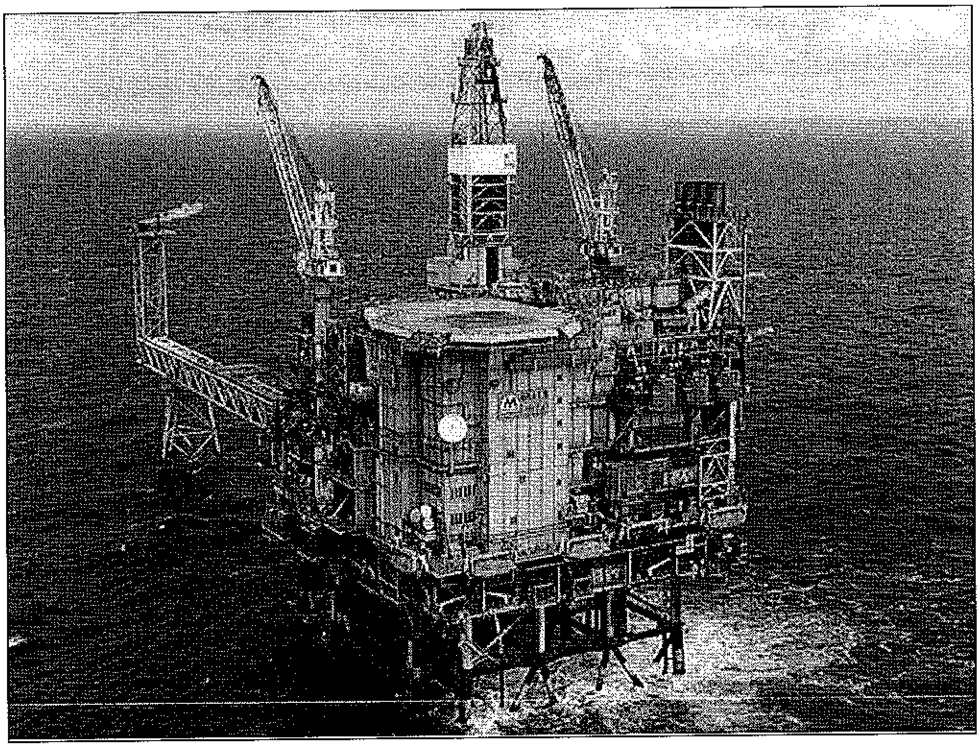


Figure 7.15: North Sea oil platform
[150, Marathon OIL, 2000]

For technical reasons and for safety, 44 % of the turbines operated offshore are of the 'dual fuel' type and can be fuelled either by natural gas from the producing field or by diesel fuel. Dual fuel turbines are usually employed to generate the electrical power required for the activities performed onboard a platform. They are operated on diesel fuel under non-routine or emergency conditions, e.g. where the gas production has been shut down. Diesel is also used for start-up operations when only a limited amount of natural gas is available. The remaining 56 % of turbines operated offshore are of the single gaseous type and are primarily used for mechanical drives, such as gas compression [124, OGP, 2000]. There are two basic types of industrial gas turbines used on offshore applications, aeroderived gas turbines and the heavy-duty gas turbines. The dual fuel (DF) reciprocating engine is a new prime mover type used in the off shore market (see Section 7.1.3.2) for more information about this type of engine.

The aeroderivative type of gas turbine is more adaptable to variable loads than the heavy-duty unit and is, therefore, widely used for gas and oil pumping, as well as for electrical power generation. The turbine may contain more than one concentric shaft to obtain optimum performance from different stages of gas expansion and air compression.

The heavy duty gas turbines are used mainly for electrical generation. They are often built as a single shaft machine where the compressor, turbine and power turbine are all on a single shaft. On start-up, the complete rotor has to be accelerated to a self-sustaining speed, usually by a diesel engine or electric motor. When used for power generation, they can maintain good speed control, even in the event of a loss of electrical load [123, DTI, 2001].

The offshore oil and gas facility, although using some combustion equipment common to onshore applications, is a more complex and potentially hazardous environment than, say, an onshore power station, which results in higher cost due to the following resons:

- logistics related to bringing people and equipment to the installation
- limited cabin capacity for additional crew during modification work, which either may mean a prolonged installation period or the need for renting a flotel (floating hotel)
- higher man-hour rates
- hot work in congested process areas is a safety hazard; thus more of the work will have to be carried out in habitats (which add to the cost) or during complete shutdown (loss of production)
- the more extensive and sophisticated fire protection systems often have to be modified too in addition to the equipment modifications
- if modifications require additional space, expensive structural work has to be added, if at all possible
- the value of lost or deferred production is often more significant than for a landbased facility.

In addition, space and weight are at a premium, leading to a much higher equipment density than is common in onshore applications. In addition, any undue complexity is generally avoided offshore, because of the weight, space, and operability factors, including safety factors [123, DTI, 2001]. Therefore, more complex systems, such as combined cycle plants, are applied only in a very few cases, as are systems which require significant chemical usage or supporting equipment offshore, e.g. flue-gas cleaning devices.

7.1.12.1 Control of emissions to air from offshore gas turbines

Consideration of the mechanisms of nitric oxide formation (see also Section 1.3.2.2) shows that the design of combustion equipment to reduce its formation by the thermal route involve limiting the overall temperature and residence time and minimising the formation of hot spots by optimising air and fuel mixing.

Improving the thermal efficiency by operating at higher temperatures, however, tends to increase nitric oxide concentrations, although mass releases may be reduced because of increased energy efficiency, but this phenomenum is, however, very machine specific. In addition, NO_X emissions may increase at part load conditions, and this should be considered when design proposals are reviewed.

Water and steam injections are available for a range of gas turbines. This requires modifying the fuel jets or installing a separate water injection manifold. Water is injected at a pre-set ratio with the fuel. For example, a 50 MW_{th} input installation would require about three tonnes/hr of water to achieve a 65 % reduction in nitrogen oxides. There is a modest increase in power output but a slight decrease in the turbine efficiency. However, water must be of at least 'high pressure

offshore facility.

Steam injection into the combustion chamber of a gas turbine has the same effect as water injection in cooling the combustor and reducing the thermal oxides of nitrogen. For a 50 MW_{th} input installation about four tonnes/hr of steam would be required to achieve a 65 % reduction in nitrogen oxides. The Cheng steam injection cycle for simultaneously reducing NO_X and increasing efficiency which can be applied to all gaseous fuel turbines with conventional combustion (diffusion flame technology) can be applied to offshore turbines as well. Conventional steam injection in gas fired turbines is described in Section 7.1.7.3.1 in this BREF, where 40 to 60 % NO_X emission reduction can be achieved with no significant increase in CO emission. However, the Cheng steam injection cycle provides solutions which makes this NO_X control technique more qualified than conventional steam injection. The Cheng system provides unique mixing of gaseous fuel and steam so that NO_X can be reduced by up to 95 %. Again, the high quality water required to produce steam is not usually readily available in an offshore facility [123, DTI, 2001].

Some turbine manufacturers are developing dry low NO_X emission (DLE) technology, using gas analyser equipment and software integrated in the fuel and engine management system, for new turbines and for retrofitting equipment. Because of the special constraints on offshore platforms (i.e. space, complexity and weight) that makes water and steam injection not a very practical solution, dry low NO_X technology is currently applied to a few gas turbines on Norwegian platforms. As reported by [122, Carstensen and Skorping, 2000], DLE turbines are installed more frequently on mechanical drive applications. This is because many turbines used in power generation have a dual fuel system. Turbines that combine lean premix features as well as liquid fuel capabilities do not yet have sufficient field experience and are, therefore, not applied to such turbines.

The NOxRED-GT can be applied to new and existing gas turbines, but the main market is on SAC turbines offshore. Since ammonia is injected in small amounts after the combustion chamber, the NOxRED-GT will not affect the burning condition and the turbine efficiency. The technique can be used on both dual fuel and single fuel turbines and is independent of the fuel quality.

Post-combustion techniques such as SCR, have been applied to gas turbines in several European countries and in parts of Japan and California, in order to meet low emission standards for nitrogen oxides. SCR is a chemical reduction of nitrogen oxides by a reducing agent, usually ammonia gas. According to the space and weight of such a system and particularly the health and safety problems encountered by the storage and handling of ammonia, this technique has not been applied and is not considered particularly viable for offshore combustion installations at the present time.

The Parametric Emission Monitoring System called PEMS can be seen as an alternative to continious monitoring CEMS offshore. PEMS is widely used in the US as NO_X monitoring techniques. In the US, the operator of an installation can apply for using PEMS instead of

reliability, accessibility and timeliness as that provided by the continious emission monitoring

7.1.12.2 Efficiency of offshore gas turbines

Open or simple cycle configurations are mostly used for offshore facilities, because of space, weight, and operability reasons. Thermal efficiencies of up to about 40 % can be expected from the latest new large gas turbines. However, for existing gas turbines under operating conditions more typical numbers are 30 – 35 % of thermal efficiency. Higher thermal efficiencies can lead to high combustion temperatures, which may increase NO_X production, thus requiring sophisticated combustion chamber designs to achieve both high thermal efficiencies, and low emissions [123, DTI, 2001].

The efficiency of the turbines themselves is only one of the factors of the total energy efficiency of the offshore installation. To obtain a more efficient energy production on the platforms, many factors need to be taken into account and some of them are listed below:

- optimisation of the process in order to minimise the energy consumption and the mechanical requirements
- using variable speed drives for large rotating equipment if loads are variable
- optimising line sizes to reduce pressure drops, using expanders and hydraulic pumps to utilise pressure drops instead of throttling
- optimise equipment sizing to avoid recycling amd part-load operation
- optimise and maintain inlet and exhaust systems in a way that keep the pressure losses as low as practically possible
- utilisation of gas turbine exhaust heat for platform heating purposes.

7.2 Examples of applied processes and techniques

This part of Chapter 7 provides a number of examples of techniques and processes currently applied in different gas combustion installations. The aim of the examples is to demonstrate how specific techniques have been applied to new or retrofitted plants in order to ensure a high level of protection for the environment as a whole, taking into account, in each case, the particular site-specific conditions and environmental requirements. However, from the information collected, it is not always clear, if or how each technique described in the examples has been assessed against the definition of BAT given in article 2 (11) of the Directive, as well as against the list of 'considerations to be taken into account generally or in specific cases when determining the best available techniques bearing in mind the likely costs and benefits of a measure and the principles of precaution and prevention' and, consequently, how the technique has been selected and applied. Furthermore, it cannot be assured that the environmental performance presented is constant and continual under all operational conditions, over which time period, whether any problems have been encountered, and what the cross-media effects are. Also, it is not always clear what the driving force is for applying the technique and how the costs and environmental benefits are related in each case. Therefore, the information provided in the following examples is meant only to provide general indications of reported current practice and cannot be considered as appropriate reference points. The techniques that are given as examples arise from information provided and assessed by members of the Technical Working Group as part of the information exchange of LCPs.

7.2.1 Individual techniques to reduce emissions from gas-fired large combustion plants

EXAMPLE 7.2.1.1 WATER INJECTION AS A PRIMARY MEASURE TO REDUCE EMISSIONS OF NO_X FROM GAS TURBINES

Description: In the example plant, water injection was applied in a 25 MW_e gas turbine, but it can also be applied to much larger turbines. Water injection can generally be performed either by the injection of a mixture of fuel and water or by injecting water through nozzles directly into the combustion chamber.

Achieved environmental benefits: Reduced emissions of NO_X as shown in Table 7.3. With the injection of water, NO_X emissions were reduced from 400 mg/Nm^3 to about 60 mg/Nm^3.

	Measured emission values
CO (mg/Nm^3)	5 7
NO_X (mg/Nm^3)	

Table 7.3: NO_X and CO emission by applying water injection to a gas turbine [44, Austrian Ministry of Environment, 2000]

Applicability: Water injection can be applied to new and existing gas turbines.

Cross-media effects: As water injection can increase the amount of CO in the turbine off-gas, a CO catalyst was installed to oxidise the CO to CO_2. Steam or water injected into gas turbines needs to be of very high purity, and therefore application of this technique requires the use of a high quality water treatment plant, which in turn may create a liquid effluent requiring disposal.

Operational data: The efficiency of the gas turbine is 36 %. The injection of water or steam to reduce NO_X can only be carried out to a certain limit. If the steam flowrate injected in the fuel burner is too high (typically the gas turbine supplier fixes a limit on steam flowrate/fuel gas flowrate = 1.2), the effects on the compressor are relevant.

Economics:

Driving force for implementation: Low NO_X emissions

Reference literature: [44, Austrian Ministry of Environment, 2000], [32, Rentz, et al., 1999], [182, OSEC, 1999].

EXAMPLE 7.2.1.2 GAS TURBINE EQUIPPED WITH A DRY LOW NO_X COMBUSTION CHAMBER

Description: The gas turbine is operated as part of a district heating plant in Austria. The gas turbine has a capacity of 40 MW_e and is equipped with a dry low NO_X combustion chamber to reduce the generation of NO_X. The basic characteristic of dry low NO_X combustors is that the air and fuel mixing and combustion both take place in two successive steps. By mixing combustion air and fuel before combustion, a homogeneous temperature distribution and a lower flame temperature can be achieved, this results in lower NO_X emissions.

Achieved environmental benefits: Low emission levels of NO_X and CO.

Applicability: Dry low NO_X technology is available for new gas turbines and can also be retrofitted to a large number of existing gas turbine types.

Cross-media effects: None.

Operational data: NO_X and CO are measured continuously. The measured data are transferred online to the competent authority.

	Measured emission as half hourly average, at 15 % O_2 (mg/Nm^3)	Remarks
NO_X	33	Dry low NO_X burner, continuous measurement
CO	35	Continuous measurement
Dust	<1	Determined by calculation
NH_3	<2	Discontinuous measurement

Table 7.4: Measured emission concentrations of a gas turbine with dry low NO_X combustion chamber

Economics: The cost of DLN combustors to be retrofitted can vary dramatically for the same size turbine offered by different manufacturers. As an example, the incremental cost of a DLN combustor for a new gas turbine from manufacturer A (5.2 MW) was approximately EUR 180000, whereas the incremental cost for a similar DLN combustor from manufacturer B (5.1 MW) was EUR 20000. The cost discrepancy is related to performance capabilities, design complexity and reliability/maintenance factors. Investment costs for retrofitting can be

e.

For new build plants, it can be assumed that dry low NO_X combustors are nowadays no more expensive than the former conventional combustors. Therefore, for new installations, the additional costs for using dry low NO_X combustors can be considered as negligible.

Driving force for implementation: Low emission levels of NO_X and CO.

Reference literature: [32, Rentz, et al., 1999], [44, Austrian Ministry of Environment, 2000], [182, OSEC, 1999].

EXAMPLE 7.2.1.3 SCR SYSTEMS APPLIED TO GAS TURBINES COMBINED WITH HEAT RECOVERY BOILERS

Description: The SCR process is a widely applied process for the reduction of nitrogen oxides in exhaust gases from large combustion installations (see Chapter 3 for detailed information). It is applied in a number of countries, such as the US and Japan and widely in Europe, particularly in Austria, France, Germany, and the Netherlands. In Italy, SCR has also been applied but only to one gas turbine not using a commercial fuel. Further applications are planned in Denmark. In the US (especially in California as described below), the use of SCR gas turbines is mostly in co-generation applications. Approximately 85 % of the estimated 300 equipped units have a capacity between 20 and 80 MW_{th}. Some units are in the 3 – 10 MW_{th} capacity range [32, Rentz, et al., 1999].

As examples:

- in case A, a simple cycle gas turbine was specified in a permit issued in California, US, with a limit of 5 ppmvd NO_X (approx. 10 mg/Nm^3) at 15 % O_2 averaged over three hours with an ammonia slip limited to 20 ppmvd at 15 % O_2. The determination was made for a 42 MW gas turbine with water injection and SCR. This turbine has been in operation since 1995 [183, Calepa, 1999].

- in another case (case B), a combined cycle gas turbine (CCGT) permit was issued in California US with a limit of 2.5 ppmvd NO_X (approx. 5 mg/Nm^3) at 15 % O_2 averaged over one hour with ammonia slip limited to 10 ppmvd at 15 % O_2. This determination was for a gas turbine nominally rated at 170 MW with dry low NO_X combustors and SCR [183, Calepa, 1999].

- in the third case (case C), a combined cycle gas turbine was operating under the limit of 3 ppmvd NO_X (approx. 6 mg/Nm^3) at 15 % O_2 averaged over three hours with the ammonia slip limited to 10 ppmvd at 15 % O_2. This emission level was achieved on a 102 MW combined cycle gas turbine also in California US. The gas turbine is equipped with dry low NO_X combustors and an SCR. This unit has been operating since October 1997 [183, Calepa, 1999].

There are other major combined cycle and co-generation power plant projects currently going through the California Energy Commission's (CEC) siting process with a limit of 2.5 ppmvd NO_X (approx. 5 mg/Nm^3) at 15 % O_2 averaged over one hour.

Achieved environmental benefits:

Parameters	Value	Comments
NO_X	3	Reference O_2 content 15 %
NO_X		
NH_3/NO_X molar ratio	0.9 - 1.6	

Table 7.5: NO_X emissions measured by using an SCR system at a gas turbine

Applicability: SCR systems can be applied to new plants but it can also be retrofitted to existing ones if it has already been taken into account at the design stage. The lifetime of an SCR system typically exceeds 5 – 8 years without any regeneration or replacement.

Cross-media effects: Ammonia is used as an additive. It use may result in a certain amount of ammonia emitted to the air.

Operational data:

Parameters	Value	Comments
Operating temperature (°C)		Catalyst based on metal oxides (V, Ti), on Ti, silica or W
		Zeolites catalyst (based on precious metal bases)
Pressure drop across the catalyst (10^5 Pa)		

Table 7.6: Operational data using an SCR system at a gas turbine

Economics:

Cost	Percentage share of total investments
Installation: • reactor housing • ammonia supply (storage, vaporisation and injection systems • flue-gas ducting • monitoring and control equipment • electro technical installations • insulation. painting, etc.	30 %
Construction and start-up	30 %
Planning, licensing, unforeseen	10 %
First catalyst filling	30 %
Total investment for the SCR unit	100 %

Table 7.7: Cost components for SCR at gas turbines

Type of catalyst	SCR		SCR after DLN retrofit
	New	Retrofit	
Catalyst volume requirements (m^3/MW_e)			
Catalyst price (EUR/m^3)			
High temperature	12000	12000	12000
Low temperature	24000	24000	24000

Table 7.8: Cost figures for SCR at gas turbines

Related operating costs include the costs incurred by ammonia consumption, steam consumption, electricity consumption, catalyst replacement, maintenance and repair, insurance and taxes, and possibly personnel, administration and catalyst disposal costs.

Advances in SCR technology in the past few years have resulted in a 20 per cent reduction in the amount of catalyst required to achieve a given NO_X target level. In addition, increasing experience gained in the design and installation of SCR units has lowered engineering costs. These two factors have substantially reduced the cost of SCR. Operating costs have also been reduced through innovations, such as using hot flue-gas to preheat ammonia injection air which lowers the power requirements of the ammonia injection system [183, Calepa, 1999], [182, OSEC, 1999].

Driving force for implementation: Reduction of NO_X emissions.

Reference literature: [32, Rentz, et al., 1999], [57, Austrian Ministry of Environment, 2000], [183, Calepa, 1999].

EXAMPLE 7.2.1.4 SCR SYSTEMS APPLIED TO GAS-FIRED ENGINE PLANTS

Description: The SCR process is a widely applied process for the reduction of nitrogen oxides in exhaust gases from large combustion installations. SCR has also been applied to gas fired engine plants mainly in the US.

Achieved environmental benefits: Low NO_X emissions.

Operational data: Table 7.9 below lists the main performance parameters of the gas fired engine plants:

	Plant A	Plant B
Location	US	US
Commissioning year	2002	2001
Plant type	Power generation	Power generation
Fuels	Natural gas	Natural gas
Combustion technique	20 gas engines	5 gas engines
Capacity	111 MW	14 MW
Secondary measure	SCR (Reagent: aqueous urea)	SCR (Reagent: aqueous urea)
NO_X without SCR (mg/Nm^3)	159	187
NO_X with SCR fresh catalyst (mg/Nm^3) at 15 vol-% O_2	5 – 19	13
NO_X reduction rate over SCR	88 – 97 %	93 %
Ammonia slip (NH_3) (mg/Nm^3) at 15 vol-% O_2	2 – 6	<2

Table 7.9: Emission levels of two gas-fired engine power plants equipped with SCR

Applicability: SCR systems can be applied to new plants but it can also be retrofitted to existing ones.

Cross-media effects: Urea is used as an additive, but it may result in a certain amount of ammonia emitted to the air. The catalyst needs to be regenerated.

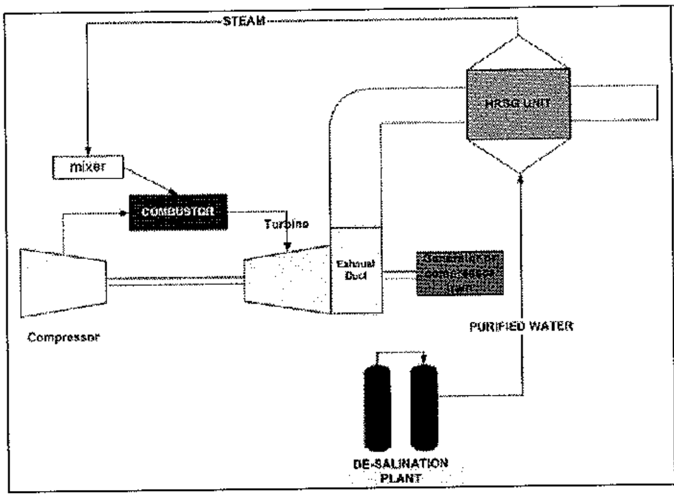
Driving force for implementation: Reduction of NO_X emissions. However, SCR has been considered mainly where local air quality sandards requested a high reduction of NO_X or ozone emissions, as a result of operation in highly populated areas or the contribution of several industries or mobile sources.

Reference literature: [78, Finkeldei, 2000], [184, Krishnan, 2002].

EXAMPLE 7.2.1.5 THE CHENG INJECTION CYCLE FOR SIMULTANEOUS NO_X REDUCTION AND EFFICIENCY INCREASE

Description: The Cheng steam injection cycle provides solutions which make this NO_X control technique more suitable than a conventional steam injection. The Cheng steam injection cycle technique provides unique mixing of gaseous fuel and steam so that NO_X can be reduced by up to 95 % with no significant increase in CO emission.

The thermal efficiency of the process is reduced if the steam is produced in a separate boiler. However, the power output from the turbine increases up to 60 %, with 50 % being the average. When using a heat recovery steam generator (HRSG) for steam production, the thermal efficiency increases. Steam for three turbines is produced by one HRSG installed on the exhaust duct from one gas turbine. This makes installation less expensive and time consuming. The Cheng steam injection cycle requires the same purity of water as a conventional steam injection.



Equipment/modifications required:

- water production plant
- HRSG
- steam piping
- gas turbine Modifications
- modifications to the turbine logical control system.

Figure 7.16: Principle sketch of Cheng Steam Injection Cycle

Since the steam will achieve the same pressure and temperature as the flue-gas in the combustion chamber, the increase in power output with will be greater than with a combined cycle.

Achieved Environmental Benefits:

- NO_X reduction (up to 95 %)
- no penalty in terms of increased CO associated with steam injection
- higher steam/fuel ratio possible than other steam injection technologies
- increase in thermal efficiency, up to 45 %, which reduces CO_2 emissions per kWh produced.

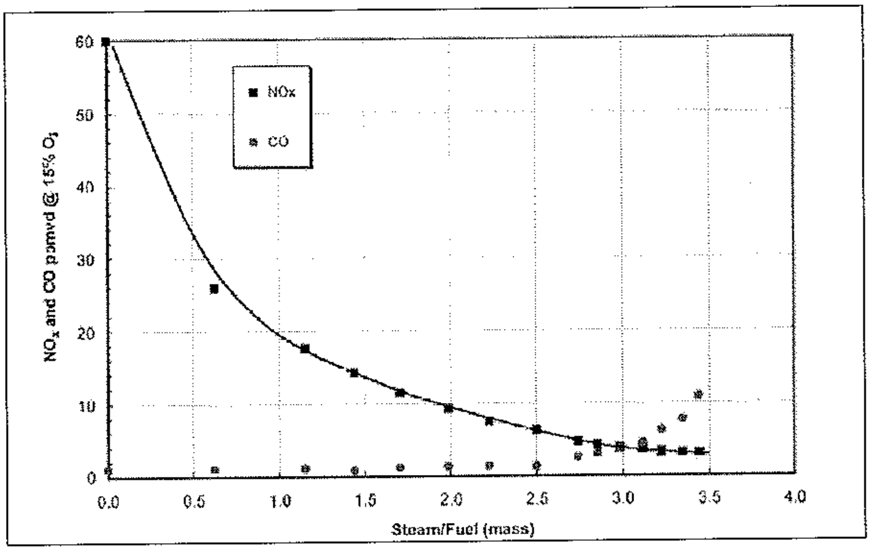


Figure 7.17: NO_X and CO emission as a function of steam ratio

Steam/fuel ratio	Achieved NO_X level (ppm)	Thermal efficiency
0	Standard configuration	34.5
1.5	25	39
3	7	44

Table 7.10: Achieved NO_X emission and thermal efficiency for conventional combustor turbines with modified fuel nozzle

Applicability: The Cheng Steam Injection Cycle is utilised at about a hundred installations in Japan, the US and Europe. The technology can, in general, be applied on all gaseous fuel fired turbines with conventional combustion (diffusion flame technology).

Necessary modifications and installations are listed below:

- replace fuel injection nozzles
- modification of GT control system
- reducing one exhaust channel and installation of boiler (HRSG)
- piping for steam from HRSG to GT generator/compressor sets
- water to be produced by either reverse osmosis or acuum distillation.

Cross-media effects: Contrary to other steam injection concepts, the Cheng Cycle also features a unique control system that allows the power plant peak (maximum) thermal efficiency to follow load changes. This should be very applicable to offshore installations where the turbine load is not constant.

Operational data: The Cheng Steam Injection Cycle can be used at all operational loads. When needed, the steam injection can simply be turned off during operation. Only higher NO_X emission rates and larger fuel consumption in order to maintain delivered power will be the effect of the turn-off action.

Economics: Calculation example:

- installed Power: 3x 22 MW each, 66 MW total.
- one HRSG installed in the exhaust duct of one gas turbine, produces steam for three turbines
- steam/Fuel ratio of 2.5
- reduction of NO_X to <10 ppm
- additional costs for support structure for the installation on an offshore platform needs to be taken into account.

	Cost (NOK million)	Weight (t)
Gas turbine rebuild	30	~1
HRSG	10	30
De-salination plant for water production	6	16

Table 7.11: Costs and weight for a Cheng steam injection cycle on a GE LM 2500 package

Driving force for implementation:

- retrofit to Cheng cycle possible for all gas turbines with conventional combustion technology (diffusion flame combustor)
- little space required on gas turbine package for modification. Therefore, emission levels lower than DLE/DLN can be achieved in offshore installations that are not prepared for DLE/DLN turbines
- retrofit and maintenance cost lower than DLE/DLN systems available
- a conventional combustion system with Cheng steam injection has a higher availability then DLE/DLN systems. Hence more applicable on gas compression trains
- emissions lower than DLE/DLN systems without CO/UHC trade-off
- many offshore installations already have a HRSG onboard, which makes the requirement for modifications, investments and installation costs lower
- increased power output or reduced fuel consumption

Reference Literature: [196, ASME,], [197, ASME,], [198, ASME,], [199, Cheng, 1997]

EXAMPLE 7.2.1.6 CATALYST POLLUTION CONTROL TECHNOLOGY FOR THE REDUCTION OF CO AND NO_X FROM COMBINED CYCLE GAS TURBINES

Description: The example technology uses a single catalyst that operates in two cycles: oxidation/absorption and regeneration. The catalyst works by simultaneously oxidising CO to CO_2, NO to NO_2, and then absorbing NO_2 onto its surface through the use of a potassium carbonate absorber coating. The regeneration of the catalyst is accomplished by passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen. The regeneration gases are steam, hydrogen and carbon dioxide. It uses no ammonia, and can operate effectively at temperatures ranging from 150 to 370 °C.

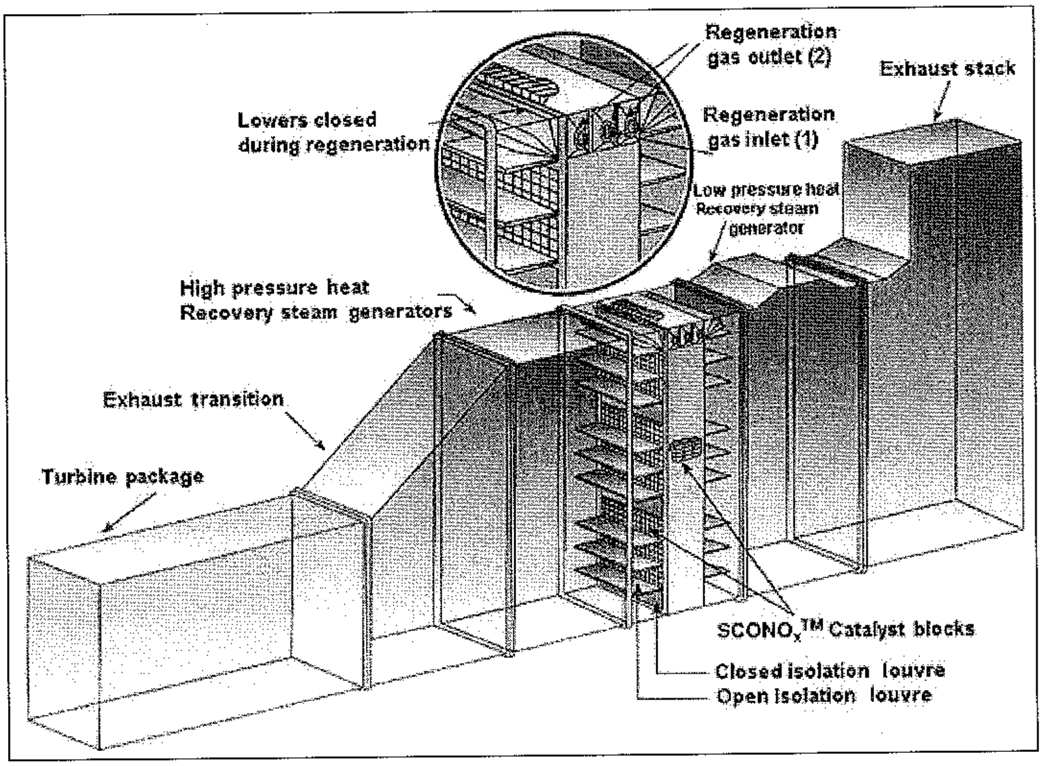


Figure 7.18: Schematic representation of the catalyst system
[26, ABB, 2000]

Achieved environmental benefits: By using this technology, combined cycle gas turbines can be operated with very low NO_X emissions levels. At the same time, the system reduces emissions of CO and non-methane volatile organic compounds. In conjunction with a sulphur removal catalyst, this system can also be used for reducing sulphur compounds from the exhaust gas.

Applicability: Applicable to both new and retrofit applications. Such a unit can be installed at

for an SCR system.

Cross-media effects: The system emits CO_2, H_2O, N_2 and trace levels of SO_2 to the stack. Due to masking and poisoning of the catalyst, it requires annual catalyst cleaning with deionised water and a potassium carbonate solution (K_2CO_3). The spent cleaning fluids can be neutralised and disposed of through the sewerage system and are harmless to the water and soil.

Operational data:

- NO_X emissions below 2 ppm (4 mg/Nm^3 as NO_2 at standard conditions: 0 °C, 1013 mbar)
- conversion rate of CO into CO_2 is 90 %
- the destruction of non-methane volatile organic compounds (NMVOC) is greater than 90 % at 315 °C
- the destruction of formaldehyde and acetaldehyde have been measured at 97 % and 94 % respectively at 150 °C.

Economics: The estimated cost numbers presented refer to a typical 400 MW size gas-fired power plant. The cost estimate numbers below are based on 8000 hours of operation per year and a NO_X reduction from 25 to 5 ppm (50 to 10 mg/Nm^3 as NO_2 at standard conditions 0 °C; 1013 mbar), which equals approx. 666 tonnes (metric) annually of NO_X removed. Included in the costings are investment cost, operating and maintenance costs and indirect annual costs.

Investment costs:	EUR 19.2 million.
This includes:	- plant equipment - delivery - fitting - commissioning/start up.

This is the total cost from the supplier.

Operating and Maintenance costs:	EUR 1.6million.
This includes:	- general maintenance - steam and natural gas consumption in the regeneration cycle - pressure drop across the unit (converted to power consumption) - average cost/year for catalyst replacement (lifetime of the catalyst is seven years) - catalyst disposal/refund.

Additional indirect annual costs to the contractor are not included.

A reduction of NO_X from 25 to 2 ppm (50 to 4 mg/Nm^3 as NO_2 at standard conditions 0 °C; 1013 mbar) will contribute to an increase in the investment costs due to the need for an additional catalyst. It will also somewhat increase the operating and maintenance cost due to the increased consumption of natural gas and steam, and due to the increased pressure drop.

Driving force for implementation: Requirements to meet very low NO_X emissions and limitations set on using air pollution control equipment utilising ammonia, especially for plants situated in densely populated areas.

Reference literature: [26, ABB, 2000].

7.2.2 Improving the environmental performance of existing gas-fired large combustion plants

EXAMPLE 7.2.2.1 COMBINED CYCLE HEAT AND POWER PLANT WITH RETROFITTED COMBUSTION CHAMBERS

Description: The example plant was commissioned in 1994 and consists of two gas turbines (2 x 67.8 MW_e) with two dedicated waste-heat boilers (2 x 26.5 MW_{th}), including auxiliary firing and one steam turbine (48.8 MW_e). The standard fuel is natural gas. Light fuel oil is used as backup fuel. The combustion chambers of the gas turbines were retrofitted in 1997 in order to reduce the emission of NO_X. NO_X reduction at the fuel oil operation is realised by the injection of demineralised water.

Achieved environmental benefits: Comparatively low emission levels are achieved due to the low NO_X technique, taking into account the size of the plant. The measures to use waste heat lead to a high overall energy efficiency and thus minimise the consumption of resources and the subsequent emission of CO_2.

Applicability: Existing boilers in an old plant might be transformed into a waste-heat boiler. In general, retrofitting measures of this kind can be applied to existing plants.

Cross-media effects: The primary measures to reduce emissions do not produce any residues. The treatment of input water produces sludge.

Operational data: In 1999, a total of 530 GWh_e of electricity and 585 GWh of district heat were produced. The plant was in operation for 4456 hours. The annual mean value for the electrical net efficiency amounted to 39.5 % and 83.1 % for the overall energy efficiency (net). The volume flowrate of the exhaust gas added up to 2 x 526000 m^3/h at an O_2 content of 14.5 %. Table 7.12 shows the atmospheric emissions in 1999.

	Monitoring	Monthly mean value[1)] (at 15 % O_2)	Specific emissions (kg/TJ fuel)
NO_X (mg/Nm^3)	Continuous	60	46.7
CO (mg/Nm^3)	Continuous	6	3.6
[1)] Equivalent to annual mean value for rated load.			

Table 7.12: Emissions to air measured in 1999

In 1999, 132 million Nm^3 of natural gas (equivalent to 43.9 MJ/kWh_e) and 181 m^3 of light fuel oil were fired.

The waste water flow of the plant originates from the treatment of the feed-water and the condensate and from the treatment of the water for the district heating circuit. (8575 m^3/yr). The main source is the regeneration of the ion exchangers. Waste water from this process is discharged after neutralisation. AOX is the only substance which is monitored regularly. The mean concentration is 0.097 mg/l. Some 2.9 tonnes of oil and oil contaminated materials were recycled and 1.6 tonnes of filter material were disposed of.

As the adjacent residential site is only 110 to 300 metres away from the single components of the plant, extensive sound reduction measures had to be realised. These comprise acoustic insulations of the boilers and the ducts, sound absorbers and the encapsulation of noisy components.

Driving force for implementation: The heat and power station is part of a municipal energy concept which aims to provide economically priced district heat in the long run. Therefore, the production of heat should be coupled to the production of electricity as far as possible. The upper power limit for the plant is determined by the heat demand and the possibilities to market the electricity.

Reference literature: [98, DFIU, 2001].

7.2.3 Environmental performance of new gas-fired combustion plants

EXAMPLE 7.2.3.1 COMBINED CYCLE HEAT AND POWER PLANT WITH AUXILIARY BURNERS AND GAS AND FUEL OIL FIRING

Description: A combined cycle heat and power station commissioned in 1995 in Germany has a total rated thermal input of 640 MW_{th}. It consists of three gas turbines with three assigned waste-heat boilers including auxiliary firing, one boiler and two steam turbines. The boiler serves to provide for peak load operation and for increased safety of supply. The operation of the whole plant is optimised to cover the heat demand. Each of the gas turbines has a rated thermal input of 135 MW_{th} and a terminal rating of 35.5 MW_e. Each of the auxiliary firings of the waste-heat boilers has a rated thermal input of 49 MW_{th}. The steam is fed to the turbines and used for the production of district heat in condensers and other heat-exchangers, i.e. the so-called peak load preheaters. Steam is also fed into a net for process steam. The electrical efficiency in 1998 was 40.2 % and the overall efficiency 59.7 %.

Primary measures for NO_X emission control: An additional system for the injection of steam was installed for the reduction of NO_X. The control system injects steam into the combustion chamber with flowrates proportional to the consumption of natural gas. This increases the power and efficiency of the turbine. Furthermore, NO_X emissions are reduced by 30 %.

Further measures: Electrostatic precipitators are installed for the removal of oil vapour which occurs during the suction of the lubricating oil tanks (separation efficiency = 92 %).

Achieved environmental benefits: Lower emission levels of NO_X, SO_2 and dust.

Applicability: The plant was retrofitted from an old lignite and heavy fuel oil-fired CHP plant. One boiler of the old plant was included in the design of the new plant and was retrofitted to be fired either with natural gas or with light fuel oil.

Cross-media effects: Not known.

Operational data: The plant was in operation for 6538 hours, equivalent to 4885 full load hours. The emission limit values of the complete plant depend on the ratio between the power input of the auxiliary firing and the power input of the gas turbine. As the emission limit values for the single units also differ in the related O_2 contents, the assigned O_2 content for dual operation must also be calculated by weighting with the share of the power input. The following tables define three operational states and the measured emissions.

Operational mode	Rated thermal input of gas turbine (MW)	Rated thermal input of auxiliary firing (MW)	Exhaust gas volume flowrate (Nm^3/h)	Related O_2 content (%)
I	123	35.6	375000	13.3
II	119	8.5	360000	14.5
III	122	0	375000	15.0

Table 7.13: Operation modes of gas turbine and auxiliary firing

Pollutant	Operation mode	Monitoring	Daily mean value (mg/Nm^3)	Specific emissions (kg/TJ Input)
NO_X	I	Continuous	73	56.16
NO_X	II	Continuous	73	53.91
NO_X	III	Continuous	82	63.13
CO	I	Continuous	60	46.12
CO	II	Continuous	27	19.88
CO	III	Continuous	9	6.97

Table 7.14: Measured atmospheric emissions in 1998

In 1998, 102.63 million Nm^3 of natural gas and 123 tonnes of fuel oil were fired. The consumption of important auxiliary supplies is shown in Table 7.15.

Auxiliary material	Oils	HCl (33 %)	NaOH (50 %)	$Ca(OH)_2$	$FeCl_3$
Application	Turbines/ hydraulic systems	Input water treatment/conditioning/ waste water treatment			
Consumption (tonnes)	1.4	169	77	23	7.4
Specific consumption (g/MWh_e)	3.4	410.5	187	55.9	18

Table 7.15: Consumption of important auxiliary supplies in 1999

A system for full water softening is applied to the water for the boiler. If surface water is used it is also decarbonised. The plant is operated with separated sewerage systems. One of them for household like sewage, and a second for rainwater and water from the boiler, the cooling system, oil separators and settling tanks. This waste water is dumped to the receiving watercourse. In 1998, 251180 m^3 cooling water and 45182 m^3 waste water from the production process were discharged.

Economics: The total investment for the plant amounted to EUR 118 million in 1998. The total operational costs in 1998 were EUR 56.1 million.

Driving force for implementation: The imposition of more stringent emission limit values meant that the retrofitting of an existing lignite and heavy fuel oil fired heat and power station would have been necessary. At the same time, the plant life needed to be extended and the economical performance needed to be improved. For these reasons, the combined cycle power plant was erected.

Reference literature: [98, DFIU, 2001].

EXAMPLE 7.2.3.2 GAS-FIRED COMBINED CYCLE HEAT AND POWER PLANT WITHOUT AUXILIARY FIRING

Description: The example power plant was erected in Germany between 1994 and 1996 with a total capacity of 380 MW_e for power and 340 MW_{th} for district heat production (at the design stage). It consists of two gas turbines (i.e. GT1 and GT2), two waste-heat boilers and three condensers for the off-take of district heat. Each gas turbine is equipped with a 21-storied compressor and 72 burners in an annular ring combustion chamber, and has a maximum power output of 185 MW_e. The standard fuel is natural gas. Light fuel oil is used as back-up fuel. The waste heat boilers (dual pressure drum boilers) produce steam at high and low pressure (77 bar/525 °C and 5.3 bar/203°C). The steam turbine (back pressure turbine) is operated with sliding pressure and generates up to 108 MW_e.

Measures for optimised efficiency: To reach high efficiencies, the gas turbines work with a compression ratio of 15:1. The turbine gas temperature reaches 1100 °C. The whole plant reaches a gross electrical efficiency of 47.4 % (at the design point). As the operation of the plant is optimised to cover the heat demand, it is often operated at part load. The design with two turbines offers high flexibility in these cases. With two turbines in operation, high efficiencies can be achieved for loads of between 60 and 100 %. With a single gas turbine these efficiencies are achieved for loads between 30 and 50 %. At the minimum load, the efficiency of the gas turbine decreases by 8 % compared to full load operation. The use of heat is optimised by:

- controlling the use of the exhaust gas heat
- preheating the gas turbine combustion air at part load
- using the waste heat from the transformer.

These measures allow an overall energy efficiency of nearly 90 % to be achieved. The efficiencies of the whole plant are summarised in Table 7.16.

	Gross efficiency related to	
	Design point	Annual mean value 1999
Electrical efficiency for CHP production	47.4 %	44.8 %
Electrical efficiency for power production only	52.6 %	49.6 %
Overall energy efficiency	89.2 %	85.9 %

Table 7.16: Efficiencies of a combined-cycle power plant without auxiliary firing

Primary measures for NO_X emission control: The annular ring-type combustion chamber of the gas turbines is equipped with 72 low NO_X burners. NO_X reduction at the fuel oil operation can be achieved by the injection of demineralised water. The combustion air can be preheated to reduce emissions either in the case of part load operation or to reduce the risk of icing. These measures allow for NO_X emissions of <100 mg/Nm^3 for natural gas and <150 mg/Nm^3 for fuel oil.

Measures for reduced emission of sound: As the residential area is only 16 m away from the

pressure level of 45 dB(A) originating from the power plant can be met by utilising the following single measures:

- adequate facade and roof
- overhead noise barrier and sound insulation of the inlet port for the combustion air
- soundproof pipes
- canals for combustion air and exhaust gas are equipped with acoustic absorbers
- stack with double walls
- 'silent' design of safety valves and *exhaust ventilator cowl*

Achieved environmental benefits: The low NO_X technique is responsible for achieving comparatively low emissions, taking into account the size of the plant. Measures to use waste heat also lead to higher overall energy efficiency and thus minimise the consumption of resources and the emissions of CO_2.

Applicability: The plant was designed to cover a high heat demand. This is the main prerequisite for a reasonable operation of plants of the same configuration. On the other hand, the single components of the plant, offering low emissions on their own, can also be integrated into power plants of a different design.

Cross-media effects: The primary measures to reduce emissions do not produce any residues. The cooling water and the waste water resulting from the operation of the plant are treated on site. Thereby screenings and sludges are produced.

Operational data: In 1999, a total of 1182.2 GWh_e and 1083.5 GWh of district heating were produced. The 3070 equivalent full load hours resulted from the demand for district heat. The volume flowrate of the exhaust gas was 1450000 m^3/h for a rated thermal input of 470 MW. Table 7.17 shows the emissions to the air in 1999.

	Monitoring	Daily mean values at 15 % O_2		Specific emissions (kg/TJ Input)	
Natural gas – firing		GT 1	GT 2	GT 1	GT 2
NO_X (mg/Nm^3)	Continuous	76.0	65.7	62.65	55.31
CO (mg/Nm^3)	Continuous	6.7	11.3	5.58	9.48
Fuel oil – firing		GT 1	GT 2	GT 1	GT 2
NO_X (mg/Nm^3)	Continuous	79.6	131.4	101.88	112.29
CO (mg/Nm^3)	Continuous	19.1	13.6	24.44	11.46

Table 7.17: Measured emissions to air in 1999

In 1999, 249.616 million Nm^3 of natural gas and 9463 m^3 of light fuel oil were fired. The consumption of important auxiliary supplies is shown in Table 7.18.

Auxiliary material	Oils	HCl (33 %)	NaOH (50 %)	NaCl brine	NH_4OH
Application	Turbines/ hydraulic systems	Waste water treatment/feed-water treatment			
Consumption	1735 litres	72 t	40 t	58 t	300 litres
Specific consumption (g/MWh$_e$)	1.5	61	34	49	0.25

Table 7.18: Consumption of important auxiliary supplies in 1999

One waste water flow originates from the treatment of the feed-water and the condensate (12000 m^3/yr). After sedimentation this water is fed into the municipal sewerage system. Further waste water results from elutriation of the boiler, depletion of the whole system and from condensates (11014 m^3/yr). This waste water is fed directly to the municipal sewerage system after cooling. Waste water from the regeneration of the ion exchangers is regularly controlled for the concentration of absorbable organic halogen (AOX). The mean value of the AOX concentration during the last five years was 0.053 mg/l.

Economics: The total investment for the new plant and the removal of the old coal-fired power station mounted up EUR 327 million in 1997. Detailed cost information is not available.

Driving force for implementation: The former heat and power station on this site could not reach the lower emission limit values in 1996. It also could no longer be operated in an economically reasonable way. The new plant offered higher efficiencies and a reduced manpower was needed for operation. The site already offered the complete infrastructure for supply and disposal. The old plant was completely demolished and the new one was built, as retrofitting the old plant could not achieve the efficiency of a new one.

Reference literature: [98, DFIU, 2001].