Cogeneration

The principle behind cogeneration is simple. Conventional power generation, on average, is only 35% efficient – up to 65% of the energy potential is released as waste heat. More recent combined cycle generation can improve this to 55%, excluding losses for the transmission and distribution of electricity. Cogeneration reduces this loss by using the heat for industry, commerce and home heating/cooling.

Cogeneration is the simultaneous generation of heat and power, both of which are used. It encompasses a range of technologies, but will always include an electricity generator and a heat recovery system. Cogeneration is also known as ‘combined heat and power (CHP)’ and ‘total energy’. In conventional electricity generation, further losses of around 5-10% are associated with the transmission and distribution of electricity from relatively remote power stations via the electricity grid. These losses are greatest when electricity is delivered to the smallest consumers.

Through the utilisation of the heat, the efficiency of cogeneration plant can reach 90% or more. In addition, the electricity generated by the cogeneration plant is normally used locally, and then transmission and distribution losses will be negligible. Cogeneration therefore offers energy savings ranging between 15-40% when compared against the supply of electricity and heat from conventional power stations and boilers.

Because transporting electricity over long distances is easier and cheaper than transporting heat, cogeneration installations are usually sited as near as possible to the place where the heat is consumed and, ideally, are built to a size to meet the heat demand. Otherwise an additional boiler will be necessary, and the environmental advantages will be partly hindered. This is the central and most fundamental principle cogeneration.

When less electricity is generated than needed, it will be necessary to buy extra. However, when the scheme is sized according to the heat demand, normally more electricity than needed is generated. The surplus electricity can be sold to the grid or supplied to another customer via the distribution system (wheeling).

The benefits of cogeneration

Provided the cogeneration is optimised in the way described above (ie sized according to the heat demand), the following benefits arise:

- Increased efficiency of energy conversion and use;
- Lower emissions to the environment, in particular of CO_2, the main greenhouse gas;
- In some cases, where there are biomass fuels and some waste materials such as refinery gases, process or agricultural waste (either anaerobically digested or gasified), these substances can be used as fuels for cogeneration schemes, thus increasing the cost-effectiveness and reducing the need for waste disposal;
- Large cost savings, providing additional competitiveness for industrial and commercial users, and offering affordable heat for domestic users;
- An opportunity to move towards more decentralised forms of electricity generation, where plant is designed to meet the needs of local consumers, providing high efficiency, avoiding transmission losses and increasing flexibility in system use. This will particularly be the case if natural gas is the energy carrier;
- Improved local and general security of supply - local generation, through cogeneration, can reduce the risk that consumers are left without supplies of electricity and/or heating. In addition, the reduced fuel need which cogeneration provides reduces the import dependency - a key challenge for Europe's energy future;
- An opportunity to increase the diversity of generation plant, and provide competition in generation. Cogeneration provides one of the most important vehicles for promoting liberalisation in energy markets;
- Increased employment - a number of studies have now concluded that the development of cogeneration systems is a generator of jobs.

Energy and cost savings

A well-designed and operated cogeneration scheme will always provide better energy efficiency than conventional plant, leading to both energy and cost savings. A single fuel is used to generate heat and electricity, so cost savings are dependent on the price-differential between the primary energy fuel and the bought-in electricity that the scheme displaces. However, although the profitability of cogeneration generally results from its cheap electricity, its success depends on using recovered heat productively, so the prime criterion is a suitable heat requirement. As a rough guide, cogeneration is likely to be suitable where there is a fairly constant demand for heat for at least 4,500 hours in the year. The timing of the site's electricity demand will also be important as the cogeneration installation will be most cost effective when it operates during periods of high electricity tariffs, that is, during the day. At current fuel prices and electricity tariffs, and allowing for installation and life-cycle maintenance costs, payback periods of three to five years can be achieved on many cogeneration installations.

Environmental savings

In addition to direct cost savings, cogeneration yields significant environmental benefits through using fossil fuels more efficiently. In particular, it is a highly effective means of reducing carbon dioxide (CO_2) and sulphur dioxide (SO_2) emissions. Oxides of nitrogen (NO_x) are also generally reduced by the introduction of modern combustion plant.

CO_2 savings

The assessment of the carbon savings from a cogeneration project is hotly debated, as it is very difficult to prove what electricity it displaces. This issue has been at the heart of a long running discussion in European markets, with no agreement. Does the cogeneration scheme displace:

a. The mix of electricity production in the country?
b. The most marginal power plant on the system?
c. The next power plant to be built by the power industry?
d. The best theoretical power plant available?

Depending on the answer the savings in carbon dioxide can vary from 100 kg per MWh to more than 1000 kg MWh. The same issue faces all projects that displace other electricity generation.

It is reasonable to assume that most new cogeneration will be gas-fired at least in the next 10 years. For example, a gas turbine with waste-heat-boiler is used here to demonstrate the savings:

Cogeneration

Gas turbine with waste heat boiler	
Heat to power ratio	1.6
Efficiency	80%
Emissions of CO2 per unit of fuel	225 g/kWh
Emissions of CO2 per kWh of electricity	581 g/kWh

If it is assumed that cogeneration displaces electricity from a mix of fuels and heat from a boiler with a mixed type of fuels, the savings per kWh will be 615g/kWh.

As explained later in this document, the current share of electricity produced from cogeneration in the EU is about 10%. The EU target is to reach 18% by 2010. The following table illustrates what this target could achieve in terms of CO_2 emissions reduction. The results are different depending on the fuel being displaced:

Fuel displaced	CO_2 savings
Coal electricity and coal boilers	342 Million Tonnes
Gas electricity and gas boilers	50 Million Tonnes
Fossil mix electricity and boilers	188 Million Tonnes

NO_x and SO_2 savings

To calculate NO_x and SO_2 savings, the same principle applies, it is necessary to look at what is being displaced. According to calculations made by ETSU, the following savings can be achieved by a gas turbine with a waste heat boiler:

Boiler replaced	NO_x	SO_2
Coal boiler	2.9 g/kWh	23.2 g/kWh
HFO boiler	2.9 g/kWh	23.4 g/kWh

Where is cogeneration suitable?

Cogeneration has a long history of use in many types of industry, particularly in the paper and bulk chemicals industries, which have large concurrent heat and power demands. In recent years the greater availability and wider choice of suitable technology has meant that cogeneration has become an attractive and practical proposition for a wide range of applications. These include the process industries, commercial and public sector buildings and district heating schemes, all of which have considerable heat demand. These applications are summarised in the table below. The table also lists renewable fuels that can enhance the value of cogeneration, although fossil fuels, particularly natural gas, are more widely used.

Possible opportunities for application of cogeneration

- Pharmaceuticals & fine chemicals
- Paper and board manufacture
- Brewing, distilling & malting
- Ceramics
- Brick
- Cement
- Food processing
- Textile processing
- Minerals processing
- Oil Refineries
- Iron and Steel
- Motor industry
- Horticulture and glasshouses
- Timber processing
- District heating
- Hotels
- Hospitals
- Leisure centres & swimming pools
- College campuses & schools
- Airports
- Prisons, police stations, barracks etc
- Supermarkets and large stores
- Office buildings
- Individual Houses

Renewable Energy

- Sewage treatment works
- Poultry and other farm sites
- Short rotation coppice woodland
- Energy crops
- Agro-wastes (ex: bio gas)

Energy from waste

- Gasified Municipal Solid Waste
- Municipal incinerators
- Landfill sites
- Hospital waste incinerators

How does cogeneration work?

Cogeneration uses a single process to generate both electricity and usable heat or cooling. The proportions of heat and power needed (heat:power ratio) vary from site to site, so the type of plant must be selected carefully and an appropriate operating regime must be established to match demands as closely as possible. The plant may therefore be set up to supply part or all of the site heat and electricity loads, or an excess of either may be exported if a suitable customer is available.

Cogeneration plant consists of four basic elements:

- a prime mover (engine);
- an electricity generator;
- a heat recovery system;
- a control system.

Depending on site requirements, the prime mover may be a steam turbine, reciprocating engine or gas turbine. In the future new technology options will include micro-turbines, Stirling engines and fuel cells. The prime mover drives the electricity generator and usable heat is recovered. The basic elements are all well established items of equipment, of proven performance and reliability.

Cogeneration plants are available to provide outputs from 1 kWe to 500 MWe. For larger scale applications (greater than 1 MWe) there is no "standard" cogeneration kit: equipment is specified to maximise cost-effectiveness for each individual site. For small-scale cogeneration applications, equipment is normally available in pre-packaged units, helping to simplify installations.

Plants for industrial applications typically fall into the range 1-50 MWe, although some larger systems have been installed. It is difficult to define what is large and what is small, because every country has different sizes and different appreciations in this respect. In general, it can be said that from 1 MWe to 10 MWe it will be medium, and bigger than 10 MWe will be large. Non industrial applications cover also a full range of sizes, from 1 kWe for a domestic dweling to about 10 MWe for a large district heating cogeneration scheme. Everything under 1 MWe can be considered small-scale. “Mini” is under 500 kWe and “micro” under 20 kWe.

Intensive developments over the past two decades have made a wide variety of equipment available, enabling cogeneration packages to be matched accurately to site requirements. Furthermore, legislation over this period has made it easier to install and operate cogeneration.

Technical status of cogeneration

Cogeneration is an established technology. Its ability to provide a reliable and cost-effective supply of energy has been proven. Indeed cogeneration has been used since the start of the 20th century, and systems can operate for at least 20 years. Cogeneration is currently used on many thousands of sites throughout the EU, and supplies around 10% of both the electricity generated and heat demand in the Community.

In the last 10-15 years, significant technological progress has been made to enable engine and turbine technology to be widely implemented and promote more decentralised forms of cogeneration and power generation. Cost-effectiveness and decreasing emissions have resulted. There are an increasing number of varied applications in industry and residential areas and which can be used in heating and cooling applications.

Some of the more minor barriers that face the remaining sites in these type of application, and which face sites in less traditional cogeneration applications, can be alleviated by technical developments.

The economics of cogeneration

In Member States where a more liberalised electricity market values cogenerated electricity transparently, cogeneration can usually be developed more freely than in markets where regulated tariffs are set. In 1995, COGEN Europe published a study “The Barriers to Combined Heat and Power in Europe” that demonstrated that many of the barriers to further development of cogeneration derived from the existence of monopolistic electricity markets. The most frequent barriers were:

- Too low tariffs for surplus cogenerated electricity sold to the grid;
- Very severe tariffs for standby power and, in particular, back-up power supply;
- Lack of freedom to ‘wheel’ (third party access) or, when allowed, too expensive to consider;
- Technical barriers. Cogeneration schemes need to fulfil certain technical and safety requirements for proper operation. Sometimes the procedures take too long and are not transparent enough.

In a liberalised market, these traditional barriers do not exist, because cogenerators are free to sell to any customer. Provided the market is properly structured, cogeneration can provide the most cost-effective option for producing electricity when the savings from heat utilisation are taken into account.

However liberalisation, as reality has proven (at the time of writing this guide, the electricity and gas markets in Europe are being liberalised and there is a long way to go before full liberalisation is achieved) at least in the short term, brings new barriers if the market is not structured in such a way that allows for fair treatment. Recent experience brings the following set of barriers:

- Due to recent and on-going changes in the legal frameworks, uncertainty is playing a very dissuasive role in the investment decisions;
- The first effect of liberalisation has in many cases been a considerable reduction in the electricity prices. In some countries the prices have been lowered below cost and this makes it unprofitable to invest in or run cogeneration plants. This is aggravated by the willingness of some governments to pay large sums of stranded cost to the electricity utilities and the massive overcapacity in old, inefficient power plants;
- Closely related to the last point, environmental costs are almost never included in the energy prices and neither are avoided costs for the use of the network;

- The adopted systems for access to the network are proving to be a new barrier in more than one country. Without going into great detail, it can be said that they are often very complicated to understand and expensive.

Because of the need to take a relatively medium term view (cogeneration is a relatively expensive capital investment), volatility and uncertainty in energy markets, tariffs or prices may deter potential investors. The economics of cogeneration are sensitive to the level of energy prices, and the differential between the price of the fuel used by the prime mover, and the value of the electricity and heat which is generated. To assist investors evaluate the impact of price changes requires that clear and transparent policies are used in the regulation and operation of energy markets, leading to relative stability and predictability of energy prices.

In the long term, provided policy makers make the necessary fine tuning to correct the market where is needed, the problems mentioned above should be solved, and cogeneration will have a good future.

Cogeneration has long been deployed in energy intensive industries that have large concurrent heat and power demands. The most commonly used system for these applications was traditionally the steam power generating cycle, using steam turbines which allowed exhaust steam to be used for process heating.

Intensive developments over the past two decades have made a wide variety of equipment available, enabling cogeneration packages to be matched accurately to site requirements. Furthermore, legislation over this period has made it easier than ever before to install and operate cogeneration.

There are four broad categories of cogeneration application:

- small-scale cogeneration schemes, usually designed to meet space and water heating requirements in buildings, based on spark ignition reciprocating engines;
- large-scale cogeneration schemes, usually associated with steam raising in industrial and large buildings applications, and based on compression ignition reciprocating engines, steam turbines or gas turbines;
- large scale cogeneration schemes for district heating based around a power station or waste incinerator with heat recovery supplying a local heating network;
- Cogeneration schemes fuelled by renewable energy sources, which may be at any scale.

Cogeneration technologies

Cogeneration plant consists of four basic elements:

- A prime mover (engine);
- An electricity generator;
- A heat recovery system;
- A control system.

Depending on the site requirements, the prime mover may be a steam turbine, reciprocating engine or gas turbine. The prime mover drives the electricity generator and waste heat is recovered. The basic elements are all well established items of equipment, of proven performance and reliability.

Prime movers

Cogeneration units are generally classified by the type of prime mover (i.e. drive system), generator and fuel used. The following sections examine the main types of cogeneration unit and the factors affecting their use and application.

Currently available drive systems for cogeneration units include:

- Steam turbines;
- Reciprocating engines;
- Gas turbines;
- Combined cycle.

New developments are bringing new technologies towards the market. COGEN Europe expects some of these to become economically available from in the next ten years.

- Fuel cells;
- Stirling engine;
- Micro-turbines.

The following table summarises the main types of systems available, together with their typical size range, heat to power ratio, efficiency and heat quality.

Typical Cogeneration Systems

PRIME MOVER	FUEL USED	SIZE RANGE (MWe)	HEAT: POWER RATIO	ELECTRICAL GENERATING EFFICIENCY	TYPICAL OVERALL EFFICIENCY	HEAT QUALITY
PASS OUT STEAM TURBINE	ANY FUEL	1 to 100+	3:1 to 8:1+	10 - 20%	UP TO 80%	STEAM AT 2 PRESS OR MORE
BACK PRESSURE STEAM TURBINE	ANY FUEL	0.5 to 500	3:1 to 10:1+	7 - 20%	UP TO 80%	STEAM AT 2 PRESS OR MORE
COMBINED CYCLE GAS TURBINE	GAS BIOGAS GASOIL LFO LPG NAPHTHA	3 to 300+	1:1 to 3:1*	35 – 55%	73 - 90%	MEDIUM GRADE STEAM HIGH TEMPERATURE HOT WATER
OPEN CYCLE GAS TURBINE	GAS BIOGAS GASOIL HFO LFO LPG NAPHTHA	0.25 to 50+	1.5:1 to 5:1*	25 – 42%	65 – 87%	HIGH GRADE STEAM HIGH TEMPERATURE HOT WATER
COMPRESS. IGNITION ENGINE	GAS BIOGAS GASOIL HFO LHO NAPHTHA	0.2 to 20	0.5:1 to 3:1* Alfa value 0.9-2	35 – 45%	65 - 90%	LOW PRESSURE STEAM LOW AND MEDIUM TEMPERATURE HOT WATER
SPARK IGNITION ENGINE	GAS BIOGAS LHO NAPHTHA	0.003 to 6	1:1 to 3:1 Alfa value 0.9-2	25 - 43%	70 - 92%	LOW AND MEDIUM TEMPERATURE HOT WATER

* Highest heat:power ratios for these systems are achieved with supplementary firing.

Steam Turbines

Steam turbines have been used as prime movers for industrial cogeneration systems for many years. High-pressure steam raised in a conventional boiler is expanded within the turbine to produce mechanical energy, which may then be used to drive an electric generator. The power produced depends on how much the steam pressure can be reduced through the turbine before being required to meet site heat energy needs. This system generates less electrical energy per unit of fuel than a gas turbine or reciprocating engine-driven cogeneration system, although its overall efficiency may be higher, achieving up to 84% (based on fuel gross calorific value).

For viable power generation, steam input must be at a high pressure and temperature. Residual heat output is relatively low grade. Typical inlet steam conditions are 42 bar/400^{O}C or 63 bar/480^{O}C. The temperature required by the process dictates actual outlet steam conditions. The higher the turbine inlet pressure, the greater the power output, but higher steam pressures entail progressively greater boiler capital and running costs. Optimum pressure therefore depends on the size of the plant and the required process steam pressures. Steam cycles have the great advantage that the associated boiler plant can be designed to operate on virtually any fuel, including gas, heavy fuel oil (HFO), coal, residues and municipal or other wastes, and are often capable of operating on a range of fuels.

The plant is capital intensive because a high-pressure boiler is required to produce the motive steam. At existing sites, where steam systems are supplied by low-pressure boilers, it will be necessary to replace these boilers with high-pressure plant, possibly retaining the original equipment as stand-by.

Steam cycles typically produce a large amount of heat compared with the electrical output, resulting in a high cost installation in terms of Euro/kWe. However, the integration of an incinerator (burning a waste fuel, such as clinical waste, farm wastes or municipal solid waste) with a steam turbine based cogeneration unit can be cost-effective. Power outputs are generally greater than 500 kWe. Incineration however raises concerns over the production of undesirable emissions. As an alternative, some types of waste can be gasified and the resultant gas used to fuel a gas turbine (or possibly even a gas engine) installation.

Steam turbines fall into two types, according to exit pressure of the steam from the turbine:

- back-pressure turbines, in which exit pressure is greater than atmospheric;
- condensing turbines, in which exit pressure is lower than atmospheric and a condenser is required.

The simplest arrangement is the back-pressure turbine in which all the steam flows through the machine and is exhausted from the turbine at a single, relatively low pressure suitable for use on-site. Where more than one grade of heat is required, the higher grade is supplied by extracting 'pass-out' steam at the appropriate pressure part-way along the turbine. Such extraction carries a penalty in terms of reduced electrical output.

Fully condensing turbines maximise power output by expanding all the steam down to a vacuum using a condenser. This produces such low-grade heat that it is not a cogeneration proposition as a general rule. However, pass-out steam can be extracted (as from back-pressure turbines) to meet site heat demand. The site heat load governs back-pressure or pass-out/back-pressure steam turbines and so the power output is dependent on that heat load. However, a pass-out/condensing turbine frees the generator of this constraint.

In district heating cogeneration schemes, the turbine condenser may be operated near or even above atmospheric pressure. This ensures that the condenser cooling water picks up enough heat to supply the district heating circuit. Nevertheless, some pass-out steam may still be needed to top up the final temperature of the circulating water.

Gas Turbines

The gas turbine has become the most widely used prime mover for large-scale cogeneration in recent years, typically generating 1-100 MWe. A gas turbine based system is much easier to install on an existing site than high-pressure boiler plant and a steam turbine. On many sites plot space is at a premium, a factor weighing heavily in favour of gas turbines. This, together with reduced capital cost and the improved reliability of modern machines, often makes gas turbines the optimum choice.

The fuel is burnt in a pressurised combustion chamber using combustion air supplied by a compressor that is integral with the gas turbine. The very hot (900ºC-1200^{o}C) pressurised gases are used to turn a series of fan blades, and the shaft on which they are mounted, to produce mechanical energy. Residual energy in the form of a high flow of hot exhaust gases can be used to meet, wholly or partly, the thermal demand of the site.

The available mechanical energy can be applied in the following ways:

- to produce electricity with a generator (most applications);
- to drive pumps, compressors, blowers, etc.

A gas turbine operates under exacting conditions of high speed and high temperature. The hot gases supplied to it must therefore be clean (i.e. free of particulates which would erode the blades) and must contain not more than minimal amounts of contaminants which would cause corrosion under operating conditions. High-premium fuels are therefore most often used, particularly natural gas. Distillate oils such as gas oil are also suitable, and sets capable of using both are often installed to take advantage of cheaper interruptible gas tariffs. In principle, residual fuels may be used if sufficiently free of contaminants, although in practice this is rare in industrial cogeneration applications. LPGs and Naphtha are also suitable, LPG being a possible fuel in either gaseous or liquid form. Waste fuels such as biogas and landfill gas are applicable providing their calorific values (or to be more precise the wobbe index) are relatively constant and their composition are consistent, ensuring that the hot gas leaving the combustion chamber is maintained at the required temperature. Note that the hot gas leaving the combustion chamber when using a low calorific value fuel such as biogas will not be the same as when operating on natural gas – it is the mass flow through the turbine that determines power output.

Waste gases are exhausted from the turbine at 450^{o}C to 550^{o}C, making the gas turbine particularly suitable for high-grade heat supply. The usable heat to power ratio ranges from 1.5:1 to 3:1 depending on the characteristics of the particular gas turbine. The plant ingests three to four times more air than is required simply to supply oxygen for combustion. The excess air is necessary to ensure correct cooling of the components in the whole gas path. It also means that the final exhaust gases contain large quantities of oxygen that may be used to support the combustion of additional fuel. This technique (supplementary firing) may be used to increase exhaust gas temperatures to 1,000^{o}C or more, raising the overall heat:power ratio to as much as 10:1 (although up to 5:1 is more typical). Supplementary firing, also known as boost firing, is highly efficient, as no additional combustion air is required to burn extra fuel. Efficiencies of 95% or more are typical for the fuel burned in supplementary firing systems. This technique is different from auxiliary firing, which does require additional combustion air, so is a less efficient method of raising temperature. Gas turbine systems consequently offer flexibility to serve variable heat loads and to meet higher temperature demands.

Exhaust gases can be used in either of the following ways:

- For direct firing and drying processes. The single flow of heat at high temperature is suitable for processes in which direct contact with combustion gases is permissible. This means that intermediate fluids (steam, hot water, heat transfer fluids) are unnecessary, and hence, in theory, the highest levels of thermal efficiency can be achieved. However, it is important to assess whether the direct use of the exhaust gases will affect product quality, and for this reason direct use is normally restricted to natural gas-fired gas turbines;

- To raise steam at medium or low pressure (normally 8-18 bar) for process or space heating in an open-cycle gas turbine cogeneration plant which comprises a gas turbine-alternator unit and a heat recovery boiler.

- To generate hot water, best for high temperature hot water applications where temperatures in excess of 140°C are required. In certain circumstances, they can also be applied to Air CHP systems;

- To raise steam in a HRSG at high pressure for use in a steam turbine (see later section on CCGT);

The 'shaft' efficiency (the proportion of heat in the primary fuel converted to mechanical power) can range from 20% to 45%, depending on the type of gas

turbine, its inlet temperature and pressure and other power-enhancing features. 25-35% is typical in practice.

It is possible to increase the turbine electrical generation efficiency, and to reduce levels of NO_X in the gases, through direct injection of steam into the combustion chamber, thus increasing volumetric flow through the turbine. The proportion of injected steam can be adjusted to follow electrical demand in situations of fluctuating steam and electrical demand. However, high-pressure, high quality steam is required, since steam injection will reduce engine life if the quality of the steam is poor. Therefore, the practice is more commonly associated with larger machines. Further, the system can be expensive to install and operate.

Gas turbines are available in a wide power output range from 250 kWe to over 200 MWe, although sets smaller than 1 MWe have so far been generally uneconomic due to their comparatively low electrical efficiency and consequent high cost per kWe output. This is starting to change (see section on new technologies).

The turbine is typically mounted on the same sub-base as its generator, with a step-down gearbox between the two to reduce the high shaft speed of the turbine to a speed suitable for the generator. A gas turbo-generators is extremely noisy and generally housed in an acoustic enclosure which, for industrial applications, is itself usually located in a factory-type building to provide weatherproofing and further noise attenuation. The enclosure also serves to contain the fire risk and to localise and minimise the fire prevention equipment required. Combustion air is taken from outside the enclosure. The intake ducting is fitted with filters to remove dust and a silencer to minimise noise. However, it is not necessary to install a gas turbine indoors. The acoustics enclosures can be of waterproof and sufficient noise attenuation fitted to reach very low levels (85 or 80 d BA are becoming accepted standards).

The substantial nature and conservative design of industrial gas turbines mean that they are inherently reliable and require minimal running maintenance. Shutdown maintenance is undertaken at extended intervals and is usually carried out by the manufacturer on a contract basis. Overall, about 96% reliability may be expected.

The gas turbine technology has been successful in developing NO_x reduction techniques. These techniques for gas turbines aim to reduce combustion chamber temperatures and thereby limit NO_x formation. This is often achieved by injection of water steam, which is traditionally used to boost power output, or more recently by dry low-NO_x burner system. Both control techniques substantially limit NO_x formation, nonetheless, where ultra low limits are specified, it can be necessary to employ end-of-pipe solutions such as Selective Catalytic Reduction (SCR). The technique chosen will depend upon the requirements of the national legislation or, in some instances, on more strict requirements imposed by local authorities or the host of the site. End-of-pipe system can provide negligible NOx emissions, but they do require additional equipment and reagents, which often add considerable initial and operating cost to the CHP plant. End-of-pipe systems rely on abating emissions rather than minimising formation through engine design, so undetected system failures can result in high emissions.

Reciprocating Engines

The reciprocating engines used in cogeneration are internal combustion engines operating on the same familiar principles as their petrol and diesel engine automotive counterparts. Although conceptually the system differs very little from that of gas turbines, there are important differences. Reciprocating engines give a higher electrical efficiency, but it is more difficult to use the thermal energy they produce, since it is generally at lower temperatures and is dispersed between exhaust gases and engine cooling systems.

The usable heat:power ratio range is normally in the range 0.5:1 to 2:1. However, as the exhaust contains large amounts of excess air, supplementary firing is feasible, raising the ratio to a maximum of 5:1. The pulsating nature of the delivery of exhaust gases from reciprocating engines makes boost firing difficult, so it is comparatively uncommon, although there are installations where the problems have been successfully overcome.

Engines and their lubricating oil must be cooled. This provides a source of heat for recovery, but it is generally low grade and is not always usable. In many applications the heat recovered from the cooling circuits and exhaust gases is cascaded together to produce a single heat output, typically producing hot water at around 100°C. Exhaust heat is always high grade, at up to about 400°C, and represents up to half of the total heat produced by the engine.

There are two types of engine, classified by their method of ignition:

Compression-ignition ('diesel') engines for large-scale cogeneration are predominantly four-stroke direct-injection machines fitted with turbochargers and intercoolers. Diesel engines will accept gas oil, HFO and natural gas. The latter is in reality a dual-fuel mode, as a small quantity of gas oil (about 5% of the total heat input) has to be injected with the gas to ensure ignition; as the engine can also run on gas oil only it is suited to interruptible gas supplies. Shaft efficiencies are 35 to 45%, and output range is up to 15 MWe. Cooling systems are more complex than on spark-ignition engines and temperatures are often lower, typically 85°C maximum, thereby limiting the scope for heat recovery. Exhaust excess air levels are high and supplementary firing is practicable. Compression-ignition engines run at speeds of between 500 and 1500 rev/min. In general, engines up to about 500 kWe (and sometimes up to 2 MWe) are derivatives of the original automotive diesels, operating on gas oil and running at the upper end of their speed range. Engines from 500 kWe to 20 MWe evolved from marine diesels and are dual-fuel or residual fuel oil machines running at medium to low speed.

Modern engines use delayed ignition timing and increased compression ratios to limit NOx formation whilst maintaining high levels of power output and efficiency. This requires sophisticated fuel injection and engine management system.

Although gas engines can be designed to achieve TA-luft requirements through primary reduction methods (ie limiting NOx formation within the engine) larger compression ignition engines are often fuelled by heavy fuel oil. De-NOx treatment of the exhaust gases is then required to reduce emissions to acceptable levels. This is normally achieved by use of SCR using either ammonia or urea as reaction agent. The scale of these installations can make the cost of this after-treatment acceptable within the plant's overall capital and operating cost.

Spark-ignition engines are derivatives of their diesel engine equivalents and have their same parameter equivalents as 90°C cooling water. They can also use exhaust gases for heat recovery purposes; thus plants can be built with 160°C hot water of 20 bar steam output.

Traditionally, shaft efficiency was lower that for compression ignition engines, at between 27% and 35%, and the output range was limited to a maximum of around 2 MWe. The new above 3 MWe spark ignition engines use pre-chamber, where the mixture is stoichiometric (see below). The small engines do not have pre-chamber and they are called open chamber engines or conventional engines. Pre-chamber engines have 44% shaft efficiencies, exactly the same as bigger diesel engines. The output of a spark-ignition engine is a little smaller, typically 83% of the diesel engines, because of the possibility of knocking.

They are suited to smaller, simpler cogeneration installations, often with cooling and exhaust heat recovery cascaded together with a waste heat boiler providing medium or low temperature hot water to site.

Spark-ignition engines operate on clean gaseous fuels, natural gas being the most popular. Biogas and similar recovered gases are also used but, because of their lower calorific value, output is reduced for a given engine size. Spark-ignition engines give up less heat to the exhaust gases (and correspondingly more to the cooling system) than diesel engines. The large lean-burn engines have typically 12% Oxygen in exhaust gases, and this can be used with supplementary firing. This typically requires some fresh air and has been used also in some cases during hours when the engine is not in operation.

The following are among the most common applications for the thermal energy produced by reciprocating engines:

- production of up to 15 bar steam utilising the heat of exhaust gases; and separate production of hot water at 85-90^{O}C from the cooling system of the engine;
- production of hot water at 100^{O}C, supplementing the temperature of cooling system water with heat from the gases;
- direct recuperation of the gases. Exhaust fumes can be used directly in certain processes, such as drying, CO_2 production, etc;
- generation of hot air. All the residual energies from the engine can be used, through the installation of suitable exchange devices, for the generation of hot air.

Reciprocating engines produce out-of-balance forces and require supports and foundations specially designed to absorb the severe vibrations created. Foundation requirements may be minimised, for example, by the use of pneumatic support systems that effectively transmit the dead-weight load only. Noise is marginally less of a problem than with gas turbines, although the low frequency component can have a disproportionately disturbing effect on the human ear. This is more difficult to attenuate and extensive acoustic shielding is required.

Reciprocating machines by their nature have more moving parts, some of which wear more rapidly than those in purely rotating machines, and have running as well as shutdown maintenance requirements. Shutdown maintenance, again usually provided by the manufacturer, is at much shorter intervals. Nevertheless, typical availability is about 90-96% -according to the Statistics from the North American Electric Reliability Council 1999, average availability are above 94-96%. When machines are run at slower speeds, they require less frequent maintenance. However, there is a penalty since the overall size and weight of the engine are greater for a given rating.

The comparative maintenance costs of gas turbines and reciprocating engines are much debated. There is unlikely to be a consensus until a larger body of cogeneration operating experience enables a truly realistic assessment of lifetime running costs to be obtained.

Gas engines are operated under two distinct air/fuel ration regimes that have a market effect upon environmental performance:

- Stoichiometric engines;

- Lean-burn engines.

In the absence of emissions legislation, reciprocating engines have generally been tuned to maximise power and efficiency. This operating regime occurs with a slightly over stoichiometric air/fuel ratio and produces relatively high NO_x emissions.

NOx emissions can be reduced markedly by operating with large excess of combustion air (lean-burn). However, this has an adverse effect upon the engine's power output and ultimately, at higher excess air levels, leads to increase CO and unburned hydrocarbons, combustion instability and misfire. Power output is typically compensated by use of turbocharging.

Stoichiometric engines tend to be smaller (typically <300 kWe) than their lean-burn counterparts and are based upon standard vehicle engine blocks with adapted cylinder heads and spark ignition systems. In contrast, modern lean-burn engines have undergone extensive redesign of combustion chamber geometry, include sophisticated electronic controls and are fitted with turbochargers to boost power output and electrical efficiency.

As with gas turbines, SCR is used for highly special applications where ultra low NOx emissions are required.

Cogeneration diesel plants HFO systems have been built in those places where gas is not available. This includes many islands and developing countries. In places where gas availability will arrive later, the plants can use HFO at the beginning and later switch to gas, or use HFO in winter and gas in summer.

Combined Cycles

Some large systems (power output generally greater than 3 MWe) utilise a combination of gas turbine and steam turbine, with the hot exhaust gases from the gas turbine being used to produce the steam for the steam turbine. This is called a combined cycle.

Gas turbine combined cycle (CCGT) systems have been adopted by public utility companies where supplies of natural gas are plentiful: power stations of up to 1,800 MWe have been constructed. In cogeneration applications of the CCGT, exhaust or pass-out steam from the steam turbine is used for process or other heating duties. The main advantage of CCGT cogeneration is its greater overall efficiency in the production of electricity, compared with the alternatives described above.

Combined cycles with gas turbines are the most common case, but they can also be designed with diesel engines. There are at least five cases running in the world.

NEW TECHNOLOGIES

Stirling engines

The Stirling engine is an external combustion device and therefore differs substantially from conventional combustion plant where the fuel burns inside the machine. Heat is supplied to the Stirling engine by an external source, such as burning gas, and this makes a working fluid, e.g. helium, expand and cause one of the two pistons to move inside a cylinder. This is known as the working piston. A second piston, known as a displacer, then transfers the gas to a cool zone where it is recompressed by the working piston. The displacer then transfers the compressed gas or air to the hot region and the cycle continues. The Stirling engine has fewer moving parts than conventional engines, and no valves, tappets, fuel injectors or spark ignition systems. It is therefore quieter than normal engines, a feature also resulting from the continuous, rather than pulsed, combustion of the fuel. Stirling engines also require little maintenance and emissions of particulates, nitrogen oxides, and unburned hydrocarbons are low. The efficiency of these machines is potentially greater than that of internal combustion or gas turbine devices.

There is a more that 60 years experience with this technology, what is newer is its use for micro-cogeneration boilers. For this type of boilers, there is a need for small engines with a capacity between 0.2 and 4 kWe. Gas turbines and even gas engines are unsuited for this kind of size (although the current smallest spark-ignition engine is 3 kWe), while the Stirling engine offers a good alternative.

The advantages of the Stirling engine are: less moving parts with low friction, no need for an extra boiler, no internal burner chamber, high theoretical efficiency and very suited for mass production. The external burner allows a very clean exhaust and gives the possibility of controlling the electrical output of the engine by reducing the temperature of the hot side. So there is the possibility of varying the electricity production regardless the need of thermal heat demand.

There are some low capacity Stirling engines in development or in the market. The electrical efficiency is still not very high and in the range of 10% (350 We engine); 12.5% (800 We engine) up to 25% (3,000 We engine), but it should be possible to design then with at least 25% electrical efficiency and total efficiency of 90%.

Microturbines

As explained in the section on gas turbines, systems smaller than 1 MWe have so far been uneconomic, but this is starting to change. Manufacturers are developing smaller and smaller systems and nowadays there are microturbines as small as 25 kWe. In general, microturbines can generate anywhere from 25 kWe to 200 kWe of electricity. Microturbines are small high-speed generator power plants that include the turbine, compressor, generator, all of which are on a single shaft as well as the power electronics to deliver the power to the grid. Microturbines have only one moving part, use air bearings and do not need lubricating oil. They are primarily fuelled with natural gas, but they can also operate with diesel, gasoline or other similar high-energy fossil fuels. Research is ongoing on using biogas.

Micro-turbines are smaller are smaller than conventional reciprocating engines, and capital and maintenance costs are lower. There are environmental advantages, including low NO_x emissions of 10-25 ppm (0_2 – 15% equivalent) or lower.

Microturbines can be used as a distributed generation resource for power producers and consumers, including industrial, commercial and, in the future, even residential users of electricity. Significant opportunities exist in five key applications:

- Traditional cogeneration,
- Generation using waste and biofuels,
- Backup power,
- Remote Power for those with “Black Start” capability,
- Peak Shaving.

Fuel Cells

Fuel cells convert the chemical energy of hydrogen and oxygen directly into electricity without combustion and mechanical work such as in turbines or engines. In fuel cells, the fuel and oxidant (air) are continuously fed to the cell. All fuel cells are based on the oxidation of hydrogen. The hydrogen used as fuel can be derived from a variety of sources, including natural gas, propane, coal and renewables such as biomass, or, through electrolysis, wind and solar energy.

A typical single cell delivers up to 1 volt. In order to get sufficient power; a fuel cell stack is made of several single cells connected in series.

Even if fuelled with natural gas as a source of hydrogen, the emissions are negligible: 0.045 ppm NOx, 2 ppm CO, 4 ppm HC.

Fuel cells offer a combination of performance and environmental advantages for on-site cogeneration:

- Their high efficiency is not compromised by small size and they operate high efficiency at low load;
- They have fewer moving parts and are not susceptible to wear-and-tear arising from the need to convert explosive combustion into mechanical energy;
- This provides reliable operation combined with infrequent servicing intervals, reducing maintenance costs and interrupted poser supply associated with conventional plant;
- Siting flexibility allows by-product heat to be used, doubling energy efficiency.

A number of different types of fuel cells are being developed. The characteristics of each type are very different: operating temperature, available heat, tolerance to thermal cycling, power density, tolerance to fuel impurities etc. They are also in very different stage of development and some of them have not emerged from the laboratory. Some are approaching commercial breakthrough. This will be covered by other briefings from COGEN Europe.

Waste heat recovery units

The heat recovery boiler is an essential component of the cogeneration installation. It recovers the heat from the exhaust gases of gas turbines or reciprocating engines. The simplest one is a heat exchanger through which the exhaust gases pass and the heat is transferred to the boiler feedwater to raise steam. The cooled gases then pass on the exhaust pipe or chimney and are discharged into the atmosphere. In this case, the composition or constituents of the exhaust gases from the prime mover are not changed.

The exhaust gases discharged, contain significant quantities of heat, but not all can be recovered in a boiler. Several factors prevent this:

- For effective heat transfer the temperature of the exhaust gases must remain above the temperature of the fluid to be heated. A minimum practical temperature difference of 30°C is typical;

- The exhaust gases must not be cooled to a temperature at which their buoyancy prevents them from rising from their point of discharge into the surrounding atmosphere, thereby ensuring proper dispersion of the gases under all weather conditions.

- The exhaust gases must not be cooled to a temperature at which acid condensation could occur. This risk is associated particularly with the combustion of oil fuels that contain some sulphur, as this can be condensed into sulphuric acid below certain temperatures.

- The latent heat of the water vapour in the exhaust gases can only be recovered by reducing the exhaust gas temperature to below 100°C, at which point the water vapour will condense into liquid form and release its latent heat. Boilers designed to do this are more efficient, but the three previous constraints still apply, limiting the applications for this technique.

One typical feature of the exhaust heat boiler (or waste heat recovery unit) is that the typical size is bigger than a conventional fuel-burning unit. This is for two main reasons:

- The lower exhaust gas temperatures require a greater heat transfer area in the boiler;

- There are practical limitations on the flow restriction. Excessive flow resistance in the exhaust gas stream must be avoided as this can adversely affect operation of the turbine or engine.

Exhaust heat boilers are not, therefore, 'off-the-shelf' items: they need to be designed for the particular exhaust conditions of the specified turbine or engine. The usual procedure is to provide the boiler supplier with details of the exhaust gas flow from which the heat is to be recovered, and with the temperature and pressure conditions of the required heat output. The boiler supplier will then be able to advise on the quantity of heat that can be recovered, and the temperature at which the exhaust gas will be discharged from the boiler.

A method commonly used to maximise heat recovery in an open-cycle system is to install an economiser as a heat exchanger in the flue gas stream leaving the boiler. The relatively cool boiler feedwater is passed through tubes within the economiser, recovering heat whilst cooling exhaust gases to 120°C or less. Economisers are also used with high-pressure boilers installed for steam cycle cogeneration. Where hot water is required, say at 60°C, the economiser may be replaced or followed by a condensing economiser (another heat exchanger) to heat the water while cooling flue gases to 80°C. This may only be used on systems using natural gas, as there is no sulphur present in the fuel, so the risk of acid corrosion is minimised.

Advantages and disadvantages of each system

This section simply lists the main advantages of each of the prime mover options for cogeneration.

	Advantages	Disadvantages
Steam Turbines	High overall efficiency; Any type of fuel may be used; Heat to power ratios can be varied through flexible operation; Ability to meet more than one site heat grade requirement; Wide range of sizes available; Long working life.	High heat:power ratios; High cost; Slow start-up.
Gas Turbines	High reliability which permits - long-term unattended operation; High grade heat available; Constant high speed enabling - close frequency Control of electrical output; High power:weight ratio; No cooling water required; Relatively low investment cost per kWe electrical output Wide fuel range capability (diesel, LPG, naphtha, associated gas, landfill sewage); Multi fuel capability; Low emissions.	Limited number of unit sizes within the Output range; Lower mechanical efficiency than Reciprocating engines; If gas fired, requires high-pressure supply or in-house boosters; High noise levels (of high frequency can be easily alternated); Poor efficiency at low loading (but they can operate continuously at low loads); Can operate on premium fuels but need to be clean of dry; Output falls as ambient temperature rises due to thermal constraints within the turbine; May need long overhaul periods.
Reciprocating Engines	High power efficiency, achievable over a wide load range; Relatively low investment cost per kWe electrical output; Wide range of unit sizes from 3 kWe (there are 2,000 3 kWe installations in Germany) upward; Part-load operation flexibility from 30% to 100% with high efficiency; Can be used in island mode (all ships do this) good load following capability; Fast start-up time of 15 second to full load (gas turbine needs 0.5 – 2 hours); Real multi-fuel capability, can also use HFO as fuel; Can be overhaul on site with normal operators; Low investment cost in small sizes; Can operate with low-pressure gas (down to 1 bar).	Must be cooled, even if the heat recovered is not reusable; Low power:weight ratio and out-of-balance Forces requiring substantial foundations; High levels of low frequency noise; High maintenance costs.
Stirling engines	Technical advantages: Much experience in high power range; Less moving parts with low friction;	Little experience in low power range; Poor shaft efficiency by the existing machines (350 –800 Watt shaft power); Better efficiency at 3,000 Watt shaft power;

	No internal burner chamber; High theoretical efficiency; Suitable for mass production. Advantages for micro-cogeneration: No extra thermal-boiler necessary; Electricity production independent from heat production; Very low emissions; Easy to control; Can be built as an interchangeable unit.	First machines have been/are very expensive.
Micro turbines	High reliability due to small number of moving parts; Simplified installation; Low maintenance requirement; Compact size; Light weight; Acceptable noise levels; Fuelled by domestic natural gas resource with expanded fuel flexibility; Competitive costs when built in quantity; Low emissions; High temperature exhaust for heat recovery; Acceptable power quality.	Costs
Fuel cells	Low emissions and low noise; High efficiency over load range; Modular design, siting flexibility, short construction time; Automated operation, quick load changes, low maintenance; Many fuels, but require processing unless pure hydrogen. Flexible heat to power ratio; Low or high-grade heat, depending on design and fuel cell type.	Costs, durability, power density, start-up time, degradation; Corrosion for liquid electrolytes, Sulphur.

Generators

Generators convert the mechanical energy in the rotating engine shaft into electricity. They can be either synchronous or asynchronous.

A synchronous generator can operate in isolation from other generating plant and the grid. This type of generator can continue to supply power during grid failure and so can act as a standby generator.

An asynchronous generator can only operate in parallel with other generators, usually the grid. The unit will cease to operate if it is disconnected from the mains or if the mains fail, so they cannot be operated as standby units. However, connection and interface to the grid is simple.

Synchronous generators with outputs below 200 kWe are usually more expensive than asynchronous units. This is because of the additional control, starting and interfacing equipment that is required. In general, above 200 kWe output the cost advantages of asynchronous over synchronous types disappear. There is a trend however, to use synchronous generators even on cogeneration units with low power output.

Cogeneration heat: power ratio

The ratio of heat to power required by a site may vary during different times of the day and seasons of the year. Importing power from the grid can make up a shortfall in electrical output from the cogeneration unit and firing standby boilers can satisfy additional heat demand.

Many large cogeneration units utilise supplementary or boost firing of the exhaust gases in order to modify the heat: power ratio of the system to match site loads.

Heat:power ratio is the measure generally used in, for example, the UK. Other countries may use the alpha value, which is the electricity to heat ratio. The greatest environmental benefits arise by maximising the alpha ratio for a particular cogeneration installation.

Trigeneration

Trigeneration can be defined as the conversion of a single fuel source into three energy products: electricity, steam or hot water and chilled water, with lower pollution and greater efficiency than producing the three products separately.

There are different methods for coupling a conventional cogeneration system with a chiller either by compression (using heat to create cooling) or by absorption (cogeneration to drive refrigeration compressors).

Trigeneration can be applied to all the applications of cogeneration:

District cooling

In recent years district cooling has been considered in many locations as a method for meeting the space cooling requirements of buildings in the residential, commercial and, at times, industrial sector. It is particularly suitable in urban areas with high density arrangement offices and residential dwellings requiring air conditioning.

In this application absorption chillers are often favoured because they don't use chlorofluorocarbons and they can be used in conjunction with cogeneration systems for thermal and electrical energy. The chilling equipment can be based centrally, with chilled water piped to users, or can be located on the premises of the user. The most economic choice will depend on the application and geographical distribution.

District cooling systems using absorption chillers often complement district heating systems, when both use heat supplied from a cogeneration plant. The heat demand in summer is lower than in winter and heat-driven district cooling, which requires the heat mainly in summer, can help to balance the seasonal demands for cogenerated heat. This increases the overall efficiency of the cogeneration system and therefore increases the environmental and other benefits that the system could bring.

District cooling is a recent concept, but is already relatively widely used in the USA and Japan. In Europe, there is awareness of the technology, but there is certainly less experience –with the possible exception of Sweden. An additional barrier that these systems face in Europe, apart of the fact that installing cooling increases the initial costs of the system considerably, is that the most suitable applications will be found in the South of Europe, which means, in countries where there is less experience of district heating (and where networks would have to be built), and hence less history among consumers or suppliers of the provision of this type of central energy.

- Cooling demand in industries

  Many industries, in particular the food industry, lack sources of cold water during summer. River water is often at temperatures 25°C to 30°C rather than the 10°C to 15°C required.

  Breweries for instance are very large consumers of refrigeration. Large quantities of beer must be cooled and stored in cooled place. In large dairies, refrigeration is required for milk cooling and for deep-frozen products. For deep-frozen food manufacturers, refrigeration demand for storage temperatures from -20°C to –30°C exist all year around.

- Cooling in individual buildings

  These systems are used in hotels, sport and leisure centres and residential accommodation. The CHP systems are smaller units, normally based on engines (gas or diesel). The heat recovery is via the engine's cooling circuit and its exhaust. To ensure a high availability of electricity there must be a simultaneous use for the heat and the heat storage facilities. A method increasing the use of recovered heat is to produce cooling using absorption chillers. This allows the CHP system to run during the summer months, when the lower demand for heating would otherwise reduce the opportunity for system operation.

The barriers facing the growth of CHP combined with cooling, can be even more severe than the barriers for CHP growth. For the time being, it increases the costs of the system considerably. Nevertheless there is an expectation that this type of application will increase substantially in the next few years.

Cogeneration installation

Operating strategies

For cogeneration plant there are three main operating regimes:

- the unit is operated to provide base load electricity and thermal output; any shortfall is supplemented with electricity from the public supply, and heat from stand-by boilers or boost heaters;

- the unit is operated to provide electricity in excess of the site's requirements, for export, whilst all the thermal output is used on site;

- the unit is operated to provide electricity for site, with or without export, and the heat produced is used on site with the surplus being exported to off-site customers.

One further option exists in which the cogeneration unit is operated primarily to provide electricity either for site use or for export, in conjunction with thermal trimming. Under these circumstances, excess thermal output is dumped (i.e. rejected to atmosphere via heat exchangers). However, the proportion of heat dumped reduces the overall efficiency of the plant. This type of scheme is a sub-optimal solution generally. The optimum regime for each site will depend on:

- electricity purchase and export tariffs;
- cost of fuel;
- availability of off-site heat customers;
- efficiency of stand-by heating plant;
- maintenance costs;
- other cogeneration operational costs (e.g. lubrication, auxiliary power requirement).

Connection to the public supply

Cogeneration systems are most often designed to operate in parallel mode, i.e. with the generator connected alongside the public supply network. This enables the import of power to supplement that generated on site and the export of power surplus to site needs. Both the public system and the cogeneration plant need to be protected against disturbance of supply caused by the parallel system. There are mandatory requirements for the provision of protective controls and procedures.

It is vitally important that the installed power plant is able to remain stable, i.e. to maintain synchronism when disturbed by load changes and system faults. A detailed evaluation of site electrical loads is an essential part of the initial design study. This will include analysis of switchgear and transformers, operational sequences, load flows and fault levels (i.e. the maximum current that can flow under a 3-phase short circuit condition). The existing public network and site network may need to be modified or reinforced to permit the installation of the cogeneration scheme.

It may be advantageous for some systems to be able to operate in island mode, that is, entirely independently of the public supply system. In particular, island mode enables the system to continue operating during times of public supply failure (a parallel-only installation shuts down with the grid). The proportion of the site capable of operating under island mode depends on installed capacity and its characteristics. The practicalities of this mode of operation need to be carefully considered, as it may require load-shedding facilities that will add to the cost of the installation.

Standby Power and Cogeneration

Cogeneration plant can be integrated with standby electrical plant but this is a complex issue and again requires careful thought and detailed understanding of the plant or process being supplied. In many cases integration may not be a cost-effective option, especially for small-scale applications. However, the use of cogeneration plant as full or partial standby can be a significant advantage and, for some sites, has been one of the deciding factors in choosing cogeneration.

Where the integration of cogeneration and standby is being considered for a new building or major refurbishment, a thorough risk analysis should be undertaken and specialist advice sought.

In cases where cogeneration alone is to provide the standby requirement, sufficient plant capacity and number of units must be provided to ensure security of supply and to cover maintenance downtime.

Fuel supply options

Theoretically, almost any fuel is suitable for cogeneration. In practice, fossil fuels, especially natural gas (for economical as well as for environmental reasons) predominate, but municipal solid waste, certain industrial gases and biomass are also important. Overtime biomass and derived gases are likely to take the place that natural gas occupies now, as the technology becomes more available and cheaper and as environmental concerns increase. In Turkey, LPG or naphtha are used as stand-by fuels in case the gas supply is cut-off. Installations may be designed to accept more than one fuel. A widespread example in the UK is dual-fuel gas/fuel oil burning, where natural gas is bought at the lower-rate interruptible tariff and is replaced with fuel oil when gas supply is interrupted during periods of peak demand. In some cases cogeneration can be three or four fuel fired so that the operator can select to operate on the cheapest fuel.

Key factors in the choice of fuel are possible incentives offered for their utilisation and the quality of the fuel. Some countries offer incentives for the utilisation of better quality fuels, such as natural gas, biomass or biogas. Low-quality fuels are sometimes cheap (but this varies for country to country) but they incur significant extra costs (on-costs) for handling and burning and to meet environmental regulations. Good quality fuels are more expensive but have fewer or no on-costs. Fuels may be solid, liquid or gaseous, and either "commercial" or "waste". Commercial fuels are fossil fuels that are extracted and treated or refined and sold nationwide. Waste fuels are by-products or adjuncts of processing. Renewable energy fuels are not normally traded commercially so are usually only economically available in specific locations.

Commercial fuels:

- Coal: Coal has been long used in CHP schemes (especially in large district heating schemes in Eastern Europe and Denmark) but the size of many modern coal-fired stations means that they are unsuitable for smaller and industrial CHP applications, since they would produce more heat that could be used even if they were not located away from the major population centres. Coal-fired CHP schemes are nevertheless still widespread in countries where coal is plentiful and cheap. Many are old, relatively inefficient and polluting, but some new plants embody advanced coal combustion technology.

- Heavy and extra heavy fuel oils

- Gas oil (diesel)

- Natural gas: the use of natural gas in power generation has been growing since the 1980s. Its cheapness, flexibility and the fact that it releases less carbon dioxide emissions per megajoule delivered than coal and oil account for this popularity.

- LPG

- Naphtha

Site appraisal

It is recommended that the appraisal of cogeneration be undertaken in two stages.

Stage 1 - An initial appraisal to determine whether it is worth committing the resources necessary to undertake a detailed feasibility study.

Stage 2 - If the initial appraisal shows that, in principle, cogeneration is a viable option for the site, then a second stage detailed technical appraisal should be undertaken. The study should be based on careful analysis of site energy demand to enable appropriate, cost effective cogeneration plant to be specified. It will also examine the effects on overall performance of plant optimisation, export of electricity and integration with any existing standby plant. At this stage, it is worth contacting the relevant government bodies to ascertain what assistance may be available.

The following table lists the questions that need to be considered at the initial appraisal stage.

Essential requirements for the successful implementation of cogeneration

		Yes/No
1.	Have all other energy saving measures been identified and either implemented or taken into consideration?	
2.	Is there a simultaneous base load requirement for electricity and heat which exceeds 20 kW and 50 kW respectively for more than 4,500 hours/year?	
3.	Is there a suitable fuel supply?	
4.	Is there suitable access and space for a cogeneration unit and is the location suitable with respect to other site functions (e.g. noise and exhaust)?	
5.	Are the fuel and electricity consumption records available on a monthly or more frequent basis?	
6.	If there are any site changes/developments planned, have the possible effects on the cogeneration size/economics been taken into account?	
7.	Is there a requirement to upgrade any part of the existing heating, electrical distribution or control system as a result of the cogeneration installation?	
8.	Is the proposed heat user near to the proposed cogeneration location and electrical distribution system?	
9.	Is there a likelihood that direct funding or an alternative route to funding is available?	

NOTE: with micro-CHP this check list is unsuitable as the market drivers for micro-CHP are quite different from other applications of cogeneration.

Site Energy Profiles

If the initial assessment suggests that it is worth proceeding further, then detailed investigatory work will have to be undertaken and resources allocated. Whether this work is undertaken in consultation with equipment suppliers, consultants or ESCOs is a matter of choice depending on financial and human resource availability.

The starting point for all detailed cogeneration feasibility studies is to gain an accurate assessment of the profile of electrical and thermal loads.

Electrical load profiles can be relatively easily determined using a portable load monitor. If major differences in consumption and load occur between normal weekdays and Saturdays or Sundays these must be determined. Also, if the monthly invoices demonstrate major seasonal variations in consumption (e.g. as a result of air conditioning loads in summer, or electric heating of portable buildings in winter) it may be necessary to use the load monitor to determine the time and duration of any such loads.

Thermal loads are more difficult to measure accurately. However, the importance of gaining an accurate understanding of the thermal load cannot be over-stressed. A number of existing cogeneration systems have not achieved their anticipated savings because the plant was inaccurately specified, sometimes on the basis of existing installed boiler capacity. For the correct specification of cogeneration, the peak thermal demand of the site is of much less importance than the base load profile. Cogeneration is generally only cost effective if a sufficiently large heating or cooling requirement exists for most of the running hours.

Correct sizing of the cogeneration unit is essential to the viability of the installation. Furthermore, the correct sizing and choice of the prime mover is only possible if the heat and electricity demands are clearly defined.

One final important point, cogeneration should not be sized based on a highly inefficient use of energy on the site. During the evaluation phase opportunities for reducing the site energy demand should be identified. Those that are cost-effective should be implemented. If they are not, then at least their impact needs to be taken into account in the sizing of the cogeneration plant. Failure to do this may result in an oversized and less economic cogeneration facility.

Other Factors

The location of the cogeneration system will also affect choice of plant. In particular, the following factors need to be considered:

- access to services, including electrical, heating and fuel supplies;
- noise emissions;
- exhaust emissions;
- ventilation and air quality requirements;
- delivery, access and positioning of the system;
- maintenance requirements.

Throughout the assessment, consider whether specialist advice would be helpful. The issues involved, especially on industrial sites, are often complex.

Selecting Appropriate Technologies for Specific Applications

The main indicators for selection of cogeneration plant are listed in the table below. In most cases, the choice of the prime mover will be determined by site requirements. This in turn will dictate the other items of plant.

Selection of prime movers for cogeneration

Steam turbines may be the appropriate choice for sites where: electrical base load is over 250 kWe there is a high process steam requirement; and heat:power demand ratio is greater than 3:1 cheap, low-premium fuel is available adequate plot space is available high grade process waste heat is available (e.g. from furnaces or incinerators) existing boiler plant is in need of replacement heat:power ratio is to be minimised, using a gas turbine combined cycle
Gas turbines may be suitable if: power demand is continuous, and is over 1 MWe (smaller gas turbines are just starting to penetrate the market) natural gas is available (although this is not a limiting factor) there is high demand for medium/high pressure steam or hot water, particularly at temperature higher than 140°C demand exists for hot gases at 450°C or above – the exhaust gas can be diluted with ambient air to cool it, or put through an air heat exchanger (Also consider using in a combined cycle with a steam turbine)

Reciprocating engines may be suitable for sites where:

power, or processes are cyclical or not continuous
low pressure steam or medium or low temperature hot water are required
there is a low heat:power demand ratio
when natural gas is available, gas powered reciprocating engines are preferred
when natural gas is not available, fuel oil or LPG powered diesel engines may be suitable
electrical load is less than 1 MWe - spark ignition (units available from 3 kWe to 10 MWe)
electrical load greater than 1 MWe - compression ignition (units from 100 kWe to 20 MWe)

Although the table above will enable a broad choice of prime mover to be made, the final selection will be on the basis of the particular site requirements.

Other prime mover options are just starting to become available, such as micro-turbines, fuel cells and Stirling engines. These tend towards the small size ranges.

Considerations also include the long-term availability and cost of fuel, the cost of electricity purchased, including charges associated with the provision of a back-up supply, and the credit earned for any exported electricity. In addition, the service and technical support available from the equipment suppliers, and the proven reliability of particular machines, may have a significant bearing on the outcome of the selection procedure.

Economic aspects

If the technical assessment shows that several alternative cogeneration schemes might be acceptable (as is frequently the case) an economic assessment needs to be prepared for each one before the final choice is made. During this evaluation there will be areas of interface with the technical assessment which may itself be modified as a result. Some technical/financial re-iteration is to be expected in order to develop the optimum package.

Capital Cost

This is the expenditure required for the establishment of an operational cogeneration on the site, and comprises:

- cogeneration unit(s) and associated plant, installed, tested and commissioned;
- fuel supply, storage and handling;
- connection charges including reinforcement of local/national electricity networks;
- all associated mechanical and electrical services, installed and commissioned;
- any new buildings, modification to existing buildings, foundations and support structures;
- operator training, first set of spare parts and any special tools needed for servicing and repair;
- engineering design; compliance with planning and building regulations, environmental requirements, fire prevention and protection etc; and external professional services engaged to handle these matters.

Prices are obtained from the appropriate manufacturers, suppliers, contractors and engineering consultants or professional advisers and added together to arrive at a "first cut" capital cost. Avoided costs, i.e. those for plant and services which would have been replaced in any case, should be identified so that the marginal cost of cogeneration can be derived. The quotations should contain sufficient performance, delivery and cost information to enable:

- realistic running costs to be derived;
- provisional installation and cash outflow programmes to be drawn up.

Capital costs typically vary from Euro 500 per kWe (for larger schemes) to more than Euro 1,800 per kWe for the very small and depending on the choice of cogeneration plant and auxiliaries required.

For gas turbine and large reciprocating engine cogeneration plant, the prime mover/generator package and associated equipment (auxiliary systems, gas compressor and back-up distillate fuel storage) frequently represent 40-60% of total installed cost. The heat recovery equipment (heat recovery boiler and heat exchangers) and associated equipment (water treatment plant, boiler feedwater pumps and deaerator) can account for a further 15-30% of the costs, depending on boiler type, steam pressure and supplementary firing system. Electrical switchgear and protection equipment amounts to 5-15% and the balance is attributable to design, project management and installation (including piping, civil and building works).

For steam cycle cogeneration plant the high-pressure boiler is the single most expensive item, followed by the steam turbine/generator.

Small-scale cogeneration plant based on spark ignition gas engines and dual-fuel diesel engines tend to be marketed as complete packages including baseframe, generator, heat exchangers and control equipment, accounting for 50-60% of the total installed cost.

Operating Costs

These are the annual costs of operating cogeneration plant and comprise:

- fuel for the prime mover, and for supplementary and auxiliary firing if applicable;
- labour for operating and servicing the plant;
- maintenance materials and labour, including scheduled maintenance carried out by the manufacturers. As some scheduled component replacements are often at long intervals, maintenance costs should preferably be averaged over say five years;
- consumables, e.g. lubricating oil, feedwater treatment chemicals, cooling tower dosing, as applicable;
- back-up electricity prices and top up and export electricity prices.

Typical operating and maintenance costs are:

For reciprocating engine cogeneration, in the range	0.0075 - 0.015 Euro/kWh
For gas turbine cycles	0.0045 - 0.0105 Euro/kWh
And for steam cycles	0.003 Euro/kWh

Net overall running costs of the cogeneration plant can be obtained by deducting the value of any exported electricity from the operating/maintenance costs.

To derive separate running costs for the cogeneration heat and electrical outputs, the manufacturers' performance figures are used to proportion fuel consumption and hence fuel costs, and similarly to allocate other costs. In most cases, this will demonstrate that heat costs are the same as or somewhat higher than before and that the critical cost in cogeneration economics is the total cost per kWh of electricity generated.

Most manufacturers offer long-term maintenance contracts to minimise the risk to end users and give visibility to the costs incurred.

Savings

If the cogeneration plant provides a relatively small proportion of the site's energy demands and the unit costs of providing top-up heat and electricity remain unchanged, annual savings are readily derived by subtracting the cogeneration total running cost from the existing cost of the energy it displaces.

However, the proportion of site energy typically provided by large-scale cogeneration is such that the costs of providing the remainder are often significantly changed. For example, the reduced amount and different load profile of imported electricity may mean higher tariffs; the reduced and possibly intermittent loading of conventional boilers may have some effect on heat costs. In this case, the use of cogeneration running costs alone is insufficient and comparison of total site energy costs with and without cogeneration is necessary.

Existing energy costs are compiled from fuel and electricity bills, internal costs records etc., updated if necessary to current price levels. If existing site energy performance is capable of significant improvement by other energy efficiency measures, these should also be appraised as a complementary or even competing option to cogeneration.

Reference:

www.cogen.org