Combined Heat and Power

Highlights

- **Process and Technology Status –** Combined heat and power (CHP), also known as cogeneration, is a system that generates electricity (or shaft power) while using the residual heat generated in the process for residential heating or production of hot water and steam for other applications. CHP currently accounts for around 9% of global power generation. CHP plants consist of a prime mover (turbine, engine), an electricity generator, a heat recovery system, and a control system. Various fuels (natural gas, coal, and biomass) and power generation technologies can be used for CHP. The most frequently used natural gas-based technologies are: 1) Gas turbines with heat recovery steam generators (HRSG); 2) Combined-cycle gas turbines (CCGT) consisting of a gas turbine with HRSG, which drives a steam turbine with a back pressure or a steam extraction system; 3) Internal combustion engines with electrical generators and heat extraction systems. Among coal-based technologies, fluidised-bed combustion (FBC) is often used to fulfill the demand for industrial steam or to feed district heating systems. Fossil fuel-based CHP technologies are relatively mature. Among more advanced technologies, fuel cell-based CHP provides opportunities for new applications and improved efficiency, however it needs to offer a significant reduction in the fuel cell cost.
- **Costs –** The investment costs of a gas-turbine CHP plant ranges from $900/kW_e$ to $1500/kW_e$, with a typical cost figure of $1000/kW_e$ (US$2008). The annual operation and maintenance (O&M) costs are approximately $40/kW_e$. The investment costs of a combined-cycle (CCGT) CHP plant range from $1100/kW_e$ to $1800/kW_e$ and more, with a typical cost figure of $1300/kW_e$. The annual O&M costs are approximately $50/kW_e$. The investment costs of a fluidised-bed combustion (FBC) CHP plant based on coal ranges from $3000/kW_e$ to $4000/kW_e$ and more, with a typical cost figure of $3250/kW_e$ and annual O&M costs of approximately $100/kW_e$. The investment costs of a gas-engine CHP plant are in the range of $850–1950/kW_e$, with a typical cost figure of $1,150/kW_e$. Its annual O&M costs are about $250/kW_e$. If biogas from anaerobic digestion is used in combination with a gas engine, the cost of the digestion and gas cleaning equipment has to be added to the above mentioned cost. Much higher costs are quoted for fuel cell based CHP.
- **Potential and Barriers –** CHP is the most efficient way to convert fossil fuels and biomass into useful energy and can make a significant contribution to meeting energy efficiency improvement targets. If natural gas is available at an affordable price, gas-based CHP may offer competitive power and heat. Coal-based CHP may also be a competitive option depending on location, generation mix and heat and power demand. In the past years, the natural gas-based CHP market has been driven by the need to exploit the energy content of costly natural gas as much as possible, and lower the overall heat and power generation costs. The increasing efficiency of the gas turbines and CCGT has provided another advantage to using CHP plants. However, governmental incentives and policies are needed to exploit the full potential of CHP technology. At present, China is a high potential market for CHP.

Process and Technology Status – Electricity generation based on fossil fuels is rather inefficient. A combined-cycle gas turbine (CCGT) plant – the most efficient technology for electricity generation (see ETSAP TB E02) - has an electrical efficiency of between 52% and 60% at full load, and some 40-48% of the fuel energy content is wasted as residual heat. Combined heat and power (CHP), or cogeneration, enables an efficient use of this waste heat. Figure 1 shows the energy flows and energy losses in global electricity generation (IEA, 2008). CHP is largely used in the industrial sector for combined production of power and steam, and for district heating of nearby cities. Small-scale CHP may also be based on internal combustion engine generators, with heat recovery from exhaust gas and cooling water. Fuel cell- based CHP is currently a high-cost option, but it offers potential for cost reduction and further efficiency improvement. CHP currently accounts for about 9% of the global power generation (IEA, 2008). In Denmark and Finland, CHP accounts for 47% and 65% of the thermal electricity generation respectively, thus excluding generation from wind, solar PV, hydro, etc. (IEA, 2009a). Table 1 lists the CHP technologies and their respective markets and/or applications (IEA, 2008). CHP plants based on natural gas or coal are usually derived from power generation technologies.

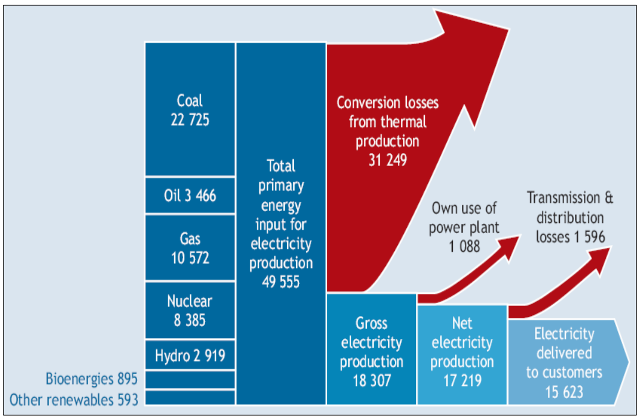

Fig. 1 - Typical Energy Flows in Global Electricity Generation (IEA, 2008) - Nuclear energy is accounted for, based on thermal energy equivalent.

Natural gas CHP technologies are: 1) gas turbines with heat recovery steam generators **(GT-HRSG)**; 2) combined-cycles consisting of a gas turbine **(CCGT)**, a HRSG which drives and a steam turbine with back pressure or steam extraction system; and (3) gas-fired internal combustion engine **(ICE)** generators with heat extraction systems. Simple-cycle or combined-cycle gas turbines are largely used for industrial cogeneration.

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Coal-based **fluidised-bed combustion (FBC)** is also an attractive CHP technology that could fulfill the steam demand of industrial facilities or feed district heating systems of nearby cities. In the case of the so-called **back-pressure** operation, coal- or gas-based CHP plants operate with a constant electricity to heat ratio. However, in the case of **controlled steam extraction** (**pass-out**), the CHP plants offer the possibility to regulate the amount of heat based on demand, and thereby optimise the total efficiency and revenues.

■ **Gas turbines with HRSG** are a cost-effective CHP option for power demand usually between a few MW_e and 25 MW_e. They perform best at full power although they can also be operated at partial load. Waste heat is recovered in the HRSG to generate high- or low-pressure steam or hot water. The thermal output can be used directly or converted into chilled water by single- or double-effect absorption chillers. Gas turbines with HRSG may also be used for district heating, but combined-cycles (CCGT) are preferred for this application because of their superior energy efficiency. Figure 2 shows the scheme of a gas turbine with HRSG (Oland, 2004).

■ **Combined-cycle gas turbines (CCGT)** are favoured in process industry applications because of their higher electrical efficiency and power range from 20 up to hundreds of MW_e. They may be designed and operated in two different ways:

- In **Back-pressure steam turbine operation** (including either unfired or fired boiler operation), the steam turbine is a non-condensing machine where all the exhaust steam is utilised for heating or processing at a lower pressure level.
- In **Controlled extraction steam turbine operation**: the steam extraction (pass-out) depends on the steam demand, while the remaining steam is condensed. This second option is the best choice for large industrial and district heating plants.

A CCGT CHP plant may be operated with a minimum electrical efficiency of about 40% based on the gas turbine simple cycle efficiency, with full utilisation of the steam for industrial use. Alternatively, in the condensing mode, the maximum efficiency of commercial combined cycles can be higher than 57%. Technology improvements aim to increase the gas inlet temperatures in the gas turbine to enable a further efficiency increase and emissions reduction in CCGT plants (Figure 3). If the gas inlet temperature increases, the power to heat ratio may also increase significantly. Whether this is cost effective or not depends on the trade-off between the higher investment costs and the lower fuel costs as a consequence of the increased efficiency.

■ **Coal- or biomass-fired fluidised-bed combustion (FBC)** plants are often used for CHP generation in industrial and district heating applications. In the FBC systems, solid fuel is mixed with an inert material (sand, ash) or limestone for sulphur control, and is kept suspended by the combustion air flowing from the combustor floor. The inert material ensures a proper

Table 1 - CHP Technologies and Markets (IEA, 2008)

	Industrial CHP	District Heating & Cooling	Commercial & Residential
Typical Users	Chemical, Refinery, Iron & Steel Glass, Coking	Private and Public Buildings	Light Manufacture Services, Buildings, Agriculture
Temp. Level	High	Low/ Medium	Low/ Medium
Size, MW_e	2 – 500	10 – 250	0.001-10
Prime Mover	Steam & Nat. Gas Turbines, ICEs, CCGT	Steam & Nat. Gas Turbines, CCGT, Waste Incinerators	ICEs, Fuel Cells Stirling Eng., Microturbines
Energy Source / Fuel	liquid, gaseous or solid fuels; industrial waste gas	liquid, gaseous or solid fuels; industrial waste gas	Liquid or gaseous fuels

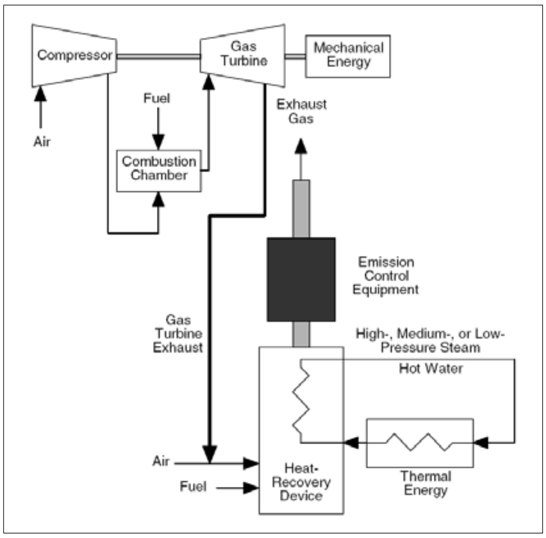

Fig. 2 - Gas-turbine CHP Plant (Oland, 2004)

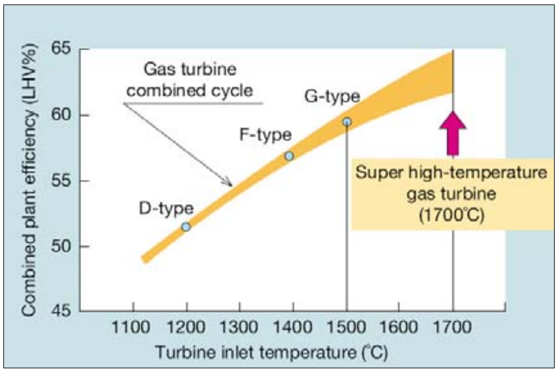

Fig. 3 - Generating efficiency of CCGT vis-à-vis turbine inlet temperature (Ishikawa et al, 2008)

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dispersion of fuel particles throughout the bed, quick heating to the ignition temperature, storage of significant amounts of thermal energy and sufficient residence time to achieve an efficient combustion. FBC also enables lower combustion temperatures than conventional systems such as pulverised coal-fired boilers. The bed turbulence improves combustion and heat transfer and allows the use of a variety of fuels, including low-quality fuels with high mineral or moisture contents such as bark, saw dust, wood chips, and other residues. Multiple fuels (co-firing) may also be used in the same unit. The bed temperature (780–900°C) is below the melting and slagging temperatures of most inorganic components (Skodras et al, 2003; Internet Source 2). FBC is being increasingly applied in Central and Eastern Europe based on both coal and lignite, and on forestry and agricultural residues. Figure 4 shows an increase of the capacity of circulating FBC over time. The first commercial CFBC plant (Gardanne, France) had a capacity of 275 MW_e. The largest CFBC plant (Lagisza, Poland) is rated at 475 MW_e.

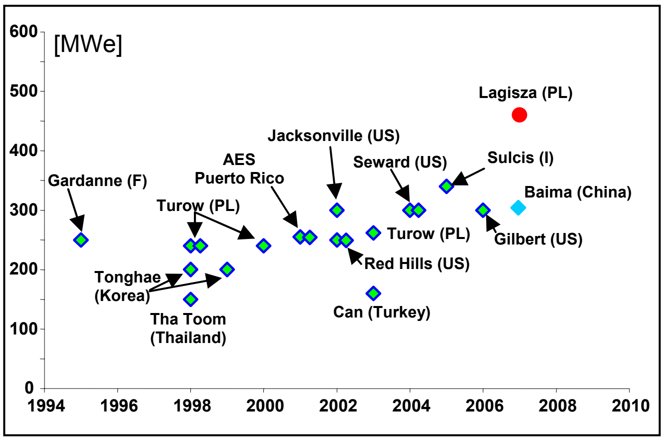

Fig. 4 - Growing capacity of CFBC plants (Minchener, 2007)

■ **Small-scale CHP based on gas-fired ICEs** is used for capacity ranging from kW_es to a few MW_e and also for applications in light manufacturing, hotels, hospitals, large urban buildings and agriculture. Gas engines may use either natural gas or landfill gas. Typical technical features are provided in Table 2. In the absence of abatement systems NO_x emissions are usually high, in the range of 700–2000 gNO_x/MWh (EPA, 2002). Post-combustion NO_x control technologies are rather complex and expensive, but in many countries strict NO_x emission limits exist. Thus, gas-engine CHP works with emission levels from 135 to 700 gNO_x/MWh, equivalent to 50- 250 mg NO_x/m^3, the lower level being obtained from using NO_x emission selective catalytic reduction (SCR) systems (Christensen et al, 2002).

Table 2 - Gas-engine CHP (EPA, 2003; MAN, 2009)

Capacity, kWe	68	800	3000
Fuel	Nat. gas	Landfill gas	
Engine speed, rpm	1500	1200	900
Fuel pressure, bar	1.2	1.2	4
Fuel input, MW_{th}	0.18	2.17	7.54
Electric heat rate[a], MJ/kWh	~10.5	9.76	9.04
El. efficiency LHV[a], %	33–35	36.9	39.8
Exhaust temp.[b],°C	N/A	465	365
Heat recovered, kW_{th}	100	1,025	3,259
Total energy effic.[a], %	~85	84.1	83.0
Power/heat ratio	~0.68	0.78	0.92

a) Electric heat rate (fuel consumed per kWh), electric and total efficiency refer to maximum efficiency (LHV) at full load.
b) Exhaust gas temperature before heat recovery.

COSTS – The main reason why industry should invest in CHP is the energy and generation cost saving compared to separate production of heat and power. CHP may entail from 15-30% energy saving compared to separate production (Figure 5, OPET, 2007), but the CHP investment cost is usually higher than the investment cost of an equivalent power plant.

The investment cost of **gas-turbine CHP plants** usually ranges from $900/$kW_e$ to $1500/$kW_e$, with a typical figure of about $1000/$kW_e$ and a peak value of $5400/kW (IEA, 2008). The operation and maintenance (O&M) costs range from $35/$kW_e$ to $55/$kW_e$ per year, with a typical value of $40/$kW_e$. The technical lifetime is 25 years and the economical lifetime is up to 20 years. Modest cost reductions are expected in the future as the technology matures. Based on technology learning the investment cost is projected to decrease to $950/$kW_e$ in 2020 and to $900/$kW_e$ in 2030.

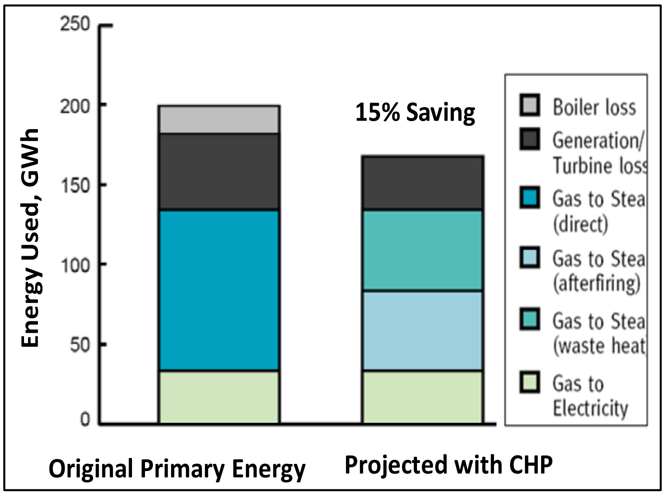

Fig. 5 - CHP projected energy saving at constant useful energy, including generation losses (OPET, 2007)

The investment cost of **CCGT CHP plants** is in the range of $1100 to $1800/$kW_e$, which is some 10-45% higher than the cost of a power-only plant, depending on the capacity of the plant. A typical cost figure is

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placed at about $1300/kW$_e$. The O&M costs are in the range of $40/kW$_e$ to $60/kW$_e$ per year (typically $50/kW$_e$). The lifetime is the same as that of the gas turbine CHP. Incremental improvements and technology learning may lead to reducing the investment cost to $1200/kW$_e$ in 2020 and $1100/kW$_e$ in 2030.

The investment cost of **FBC CHP plants** based on coal or solid biomass ranges from $3000/kW$_e$ to $4000/kW$_e$ and more, depending on the size of the plant (costs refer to the electric capacity for the condensation mode, i.e. without heat supply). A typical figure is $3250/kW$_e$. The O&M costs range from $90/kW$_e$ to $120/kW$_e$ per year (typically, $100/kW$_e$). The technical lifetime may be 40 years or more while the economical lifetime is estimated at approximately 25 years. Based on incremental advances, projected investment costs are in the order of $3000/kW$_e$ in 2020 and $2850/kW$_e$ in 2030.

Natural gas-fired **ICE CHP** systems range from $850/kW$_e$ to $1950/kW$_e$, with a typical investment cost of $1150/kW$_e$ and O&M costs of $200-300/kW$_e$ per year. The technical lifetime is 20 years while the economical lifetime is approximately 15 years. Investment costs are projected to decline to $1050/kW$_e$ in 2020 and to $1000/kW$_e$ in 2030.

POTENTIAL AND BARRIERS – The International Energy Agency in its energy policy scenario studies (IEA, 2008) provides an estimate of the impact of the CHP option on global cumulative investments in the electricity sector for two different scenarios, i.e. the *Alternative Policy Scenario* (APS) and the *Accelerated CHP* development and deployment, by 2015 and 2030 (Figure 6). This analysis provides a quantitative estimate of the significance and potential of CHP technology in global energy scenarios. According to Siemens, (Siemens, 2009), the main benefits of the industrial cogeneration are:

- Energy and fuel savings in the range of 15-30%
- Increased energy supply security and reliability, including minimisation of unscheduled shutdowns.
- Environmental protection and minimisation of CO_2 and other emissions (NO_x) due to high efficiency and conventional abatement technologies.
- Operation flexibility to meet industrial needs, varying power to heat demand ratio, and fuel and electricity prices.

Moreover, increasing electric efficiency of combined-cycles (CCGT) and coal-fired technologies lead to an improved performance of CHP systems.

CHP is the most efficient way to convert fossil fuels and biomass into final energy (electricity and heat) and can make a significant contribution to meeting energy efficiency targets. If natural gas is available at an affordable price, gas-based CHP may offer competitive power and heat. Coal-based CHP may also be a competitive option depending on location, generation mix and heat and power demand. In the past years, the natural gas-based CHP market has been driven by the need to exploit the energy content of costly natural gas as much as possible, and to lower the overall heat and power generation costs. The increasing efficiency of gas turbines and CCGT has provided another advantage to using CHP plants. However, governmental incentives and policies are needed to exploit the full potential of the CHP technology. At present, China is a high potential market for CHP.

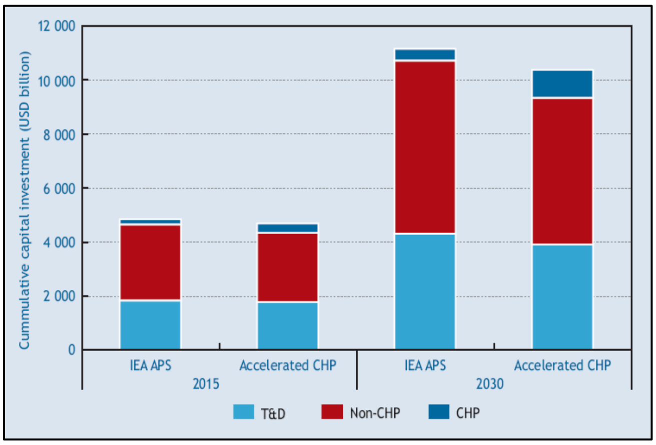

Fig. 6 - Cumulative global investment cost projection for the power sector (IEA Alternative Policy Scenario 2008)

Table 3 – Summary Table: Key Data and Figures for Gas-fired Industrial CHP

Technical Performance	GT CHP			CCGT CHP		
Electric efficiency, %	30 – 36%			42 – 47%		
Thermal efficiency (steam), %	50 – 44%			38 – 33%		
Construction time, months	Minimum 18; Typical 24; Maximum 30					
Technical lifetime, yr	25					
Load (capacity) factor, %	70 – 80			75 – 85		
Max. (plant) availability, %	95			90 – 95		
Typical (capacity) size, MW_e	5 – 25			12 – 300		
Installed (existing) capacity, GW_e	N/A					
Environmental Impact						
CO_2 and GHG emissions, kg/MWh	450 – 550			400 – 500		
NO_x, g/MWh	50			30		
Costs	**Typical current international values and ranges**					
Investment cost, incl. IDC, $/kW	900 – 1,500; Typical 1,000			1,100 – 1,800; Typical 1,300		
O&M cost (fixed & variable), $/kW/a	40			50		
Net fuel cost, $/MWh	40 – 60			30 – 45		
Economic lifetime, yr	20					
Interest rate, %	10					
Net production cost, $/MWh	65 – 75/Typical 70			60 – 75 / Typical 67.5		
Market share, %	~ 6					
Data Projections	**2010**		**2020**		**2030**	
Technology	**GTCHP**	**CCGTCHP**	**GTCHP**	**CCGTCHP**	**GTCHP**	**CCGTCHP**
Net electric efficiency, %	30–36	42–47	32–37	44– 48	34–38	46–49
Thermal efficiency (steam), %	50–44	38–33	48–43	36–32	46–42	34–31
Investment cost, incl. IDC, $/kW	1,000	1,300	950	1,200	900	1,100
Net production cost, $/MWh	70	67.5	68.5	65	67	62.5
Market share, % of global electricity	~ 7		~ 10		~ 13	

Table 4 – Summary Table: Key Data and Figures for Coal-based Industrial CHP and Gas-fired ICE CHP

Technical Performance	FBC			Gas engine		
Electric efficiency, %	24 – 28%			30 – 42%		
Thermal efficiency (steam), %	64 – 62%			50 – 44%		
Construction time, months	Min. 20; Typical 28; Max.36			Min. 10; Typical 14; Max. 18		
Technical lifetime, yr	40+			20		
Load (capacity) factor, %	75 – 85			50 – 60		
Max. (plant) availability, %	95			90 – 95		
Typical (capacity) size, MW_e	15 – 200			0.07– 6(typical size 750–1,600)		
Installed (existing) capacity, GW_e				146 (2003, incl. power only)		
Environmental Impact						
CO_2 & GHG emissions, kg/MWh	675 – 750			450 – 550		
SO_2, g/MWh	500 – 600					
NO_x, g/MWh	400 – 700			140–700		
Particulates, g/MWh	70 – 80					
Costs	**Typical current international values and ranges**					
Investment cost, incl. IDC, $/kW (	3,000 – 4,000; Typical 3,250			850 – 1,950; Typical 1,150		
O&M cost (fixed & var.), $/kW/a	90–120			200–300		
Net fuel cost, $/MWh	20 – 25			40 – 60		
Economic lifetime, yr	25			15		
Interest rate, %	10					
Net production cost, $/MWh	45 – 75 / Typical 62.5			65 – 85 / Typical 75		
Market share, %	~ 6					
Data Projections	**2010**		**2020**		**2030**	
Technology	**FBC(coal)**	**Gas eng.**	**FBC (coal)**	**Gas eng.**	**FBC (coal)**	**Gas eng.**
Net electric efficiency, %	24–28	30–42	26–30	32–42	28–32	34–42
Thermal efficiency (steam), %	64–62	50–44	62–60	48–44	60–58	46–44
Investment cost, incl. IDC, $/kW	3,250	1,150	3,000	1,050	2,850	1,000
Net production cost, $/MWh	62.5	75	61	72.5	60	70
Market share, % global electricity	~ 2		~ 5		~ 8	

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