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Study on the state of play of energy efficiency of heat and electricity production technologies

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OVERVIEW

This report provides an overview of the current state of the art of the technologies used in EU for power and heat generation as well as combined heat and power generation (cogeneration or CHP). The technologies are categorised per fuel but also in terms of technology selection. The fuels considered are the ones reported in the Strategic European Energy Review report on Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport (SEC(2008) 2872).

Coal is being used primarily in furnace boilers where by using steam generation (of subcritical supercritical or ultra super-critical quality) power is generated in steam turbine. Currently the efficiencies achieved range from 33% to 47% depending on parameters such as fuel quality, conversion technology and local climatic conditions. Coal is also used in plant that use IGCC technologies, either by firing directly coal or by mixing it with biomass. The efficiency achieved so far in this case is from 39% to 46%. Co firing of coal and either biomass or waste also takes place in fluidised bed combustions chambers, either bubbling or circulating in atmospheric or advanced pressures. Currently, supercritical pulverised coal (SCPC) power - a mature technology - is the dominant option for new coal-fired power plants. An alternative to the SCPC technology is the integrated gasification combined cycle (IGCC). The IGCC technology is less mature than SCPC technology. Few IGCC plants have been built worldwide, including 4 >10 MW sites in Europe. They have efficiency similar to that of SCPC plants, but lower non-greenhouse gas (GHG) emissions. The generating efficiency of SCPC plants is expected to increase from the current maximum value of 46% (LHV) to some 50% for 'ultra- supercritical' technology in 2020. Efficiency and reliability improvements are also expected for the IGCC technology. Its efficiency is estimated to grow from 46% in 2010 to 52% in 2020. In the IGCC plants, the production of CO_2 during the gasification process offers the opportunity for relatively low-cost CO_2 capture and storage (CCS). Due to the increase in material prices, particularly steel and equipment, the investment cost of a pulverised coal-fired power plant increased from €1050/kWe in 2000 to approximately €1540/kWe in 2008. The IGCC investment cost is relatively high. It may be up to almost twice the cost of SCPC plants. The operation and maintenance cost (O&M cost, expressed in €/kWe per year) is estimated at 4% of the investment cost per year for both SCPC and IGCC, but the IGCC plants may face higher O&M costs because of a lower technology maturity. Average costs of electricity today from SCPC are €30–35/MWh (typically €32/MWh), of which €7–12/MWh is for the fuel. For IGCC plants, corresponding figures are €40–50 (typically €50/MWh), with €5–9/MWh for the fuel.

There are two types of **gas**-fired power plants, viz. open-cycle gas turbine (OCGT) plants and combined-cycle gas turbine (CCGT) plants. OCGT plants offer moderate electrical efficiency of between 35% and 42% (lower heating value, LHV) at full load. Their efficiency is expected to reach 45% by 2020. CCGT is the dominant gas-based technology for intermediate and base-load power generation. Over the last year a significant increase of the CCGT efficiency has been achieved, with simultaneous reduction of investment costs and emissions. The CCGT electrical efficiency is expected to increase from the current 52–60% (LHV) to some 64% by 2020. In general, because of the lower investment costs and the higher fuel (natural gas) cost vs. coal-fired power, CCGT plants have lower share in base-load operation. Due to the high price of materials and equipment and the increasing demand for new CCGT plants, the investment cost of CCGT power plants has been increasing almost continuously from some €390/kWe in

2002 to €540/kWe in 2009. Technical developments in CCGT plants may drive cost reductions from today's €540/kWe to €490/kWe in 2020, and to €460/kWe in 2030. The investment cost of OCGT plants is approximately €320/kWe. Modest cost reductions are also expected for OCGT plants, namely €420/kWe in 2020, and €390/kWe in 2030. The annual operation and maintenance costs of CCGT and OCGT plants are estimated at 4% of the investment costs per year. The generation costs of CCGT range between €32 and €39/MWh (typically, €36/MWh), of which €15–22/MWh is for the fuel. Generation costs of OCGT are much higher, e.g. €100–115/MWh (typically, €102/MWh), of which €21–35/MWh is for the fuel. In the OCGT plants, the fuel cost may be up to 50% higher than in CCGT as the efficiency is about two-thirds that of a combined cycle. However, the main reason for the OCGT high generation cost is the low load-factor of the peak-load services, typically 10% vs. 50-60% for the CCGT plants.

Biomass supplies about 1% of the EU electricity demand, i.e. some 257 TWh per year. Biomass and waste also supply approximately 4.5 EJ (105 Mtoe) of direct heat to the industrial and residential sectors, and 2 to 3 EJ (47 to 70 Mtoe) of heat from combined heat and power (CHP) plants. The use of solid biomass has a significant impact on the energy balance of countries and regions with abundant primary resources such as the European Nordic countries, Austria, and Switzerland while the use of biogas is increasing in Germany, the Netherlands, the United Kingdom, and Italy. Power generation based on biomass and waste, as well as on biomass co-firing in coal-fired power plants, is also rapidly growing. Biomass-fired power plants have capacities ranging from a few MW_e up to 350 MW_e. Biomass integrated gasification combined cycles (BIGCC) are currently in the process of entering the market. The investment costs of biomass power plants are between €2100 and €4200/kW_e. The incremental investment cost and the annual O&M cost of biomass co-firing in coal-fired power plants are approximately €235/kW_e and about €8/kW_e, respectively.

In **waste** incineration, fluidised bed technology is used in 15 - 30 MW heat and low pressure steam producing boilers. When a suitable energy user is available an energy efficiency range of 70 - 90 % can be achieved. Rotating fluidised bed incinerators have been designed for thermal capacities from 10 - 55 MW (thermal). Thermal efficiency is about 80 %, and electrical efficiency typically around 25 %.

The global installed **wind** capacity has grown at 29% annual average between 2000 and 2009 and added 35.7 GW in 2010. The cumulative capacity achieved 194.4 GW at the end of 2010. In the EU27 9.3 GW of new wind capacity was installed during 2010, bringing the cumulative capacity to 84 GW. The contribution of the offshore market is low. At the end of 2010 the installed offshore capacity was slightly above 3 GW. Wind speed is the most important factor affecting wind turbine (WT) performance. The economic potential of wind power in the EU27 is 1336 TWh/y, which is equivalent to 40% of the current GEG. The country with highest potential is the UK with 344 TWh/y followed by Germany with 262 TWh. Offshore WTs operate a corrosive and tough working environment and require higher reliability by lower maintenance than onshore installations. Furthermore, grid extension is more costly and technologically challenging. Onshore wind turbine installation cost in 2009 were 1150 €/kW. Offshore prices were 3560 €/kW in 2009 with O&M costs ranging around 12-17 €/MWh for onshore and 15-33 €/MWh for offshore installations.

The global installed **hydropower** capacity achieved 723 GWe in 2010 generating around 3190 TWh/y, which is equivalent to 16% of the global electricity generation. Hydropower generation in the EU27 was 323 TWh in 2010. This accounts to 9.8% of gross electricity generation and around 60% of electricity generation from renewable energy sources. There are two hydropower plant configurations: dams and run-of-river schemes. The first is with reservoir, the other without. Run-of-river plants operate in a continuous mode, contributing to base-load electricity. The dam schemes can be subdivided into small and large, with 10 MW being the separation line. There are over 21000 small hydropower plants in the EU27, but they cover only 13% of the generated hydropower. In 2008, capital investment costs for building large hydropower facilities (>250 MW) were of the order of 1000 to 3600 €/MW. In 2008, average capital costs for small hydropower plants were of the order of 2000 to 7000 €/kW.

The global annual installed **PV** capacity in 2010 was 16.6 GWp. 13.2 GWp were installed in the EU with 7.4 GW being in Germany, 2.3 GW in Italy, 1.5 GW in the Czech Republic and 2 GW in the other member states. For 2011 this increased to 21 GW. Solar photovoltaic technologies are classified as first, second and third generation. First generation PV is the basic crystalline silicon (c-Si) technology. Second generation PV implies the Thin Film (TF) technologies. Third generation PV, often also mentioned as emerging technologies, includes Concentrator PV (CPV) and organic solar cells. The efficiency of mono-crystalline modules is in the range of 13-19% and that of multi-crystalline modules is in the range of 11-15%. Thin film modules have a record commercial efficiency of 12.1%, with a lab cell record of 20.3%. Organic solar cells achieve efficiencies around 6% for very small areas and below 4% for larger areas. High Concentration PV (HCPV) has also a very promising cost reduction potential. The current III-V cell has an efficiency of 42.4%. Efficiencies above 50% can be expected on the longer run. The most applied system layout is a Fresnel lens focusing directly on a 1 cm^2 cell, and this system's efficiency is typically in the range of 20-25%. Large systems in Germany have achieved in 2010 system costs around 2700 €/kWp. Smaller rooftop PV installations are more expensive than large solar farms. Prices of an installation of few kWs are typically around 3500 €/kWp.

Concentrated solar power utilises solar energy as the heat source in a thermodynamic cycle to produce power. These systems can supply the needed thermal energy for a conventional steam turbine (Rankine cycle), and even for a gas turbine (Brayton cycle) or a Stirling engine in the case of higher concentration factors. CSP technologies have much in common with fossil fuel power plants. The main difference is the source of the heat, which is solar in one case and the result of combustion in the other. The most advanced CSP technology today is the parabolic trough power plant. Parabolic trough power plants could also integrate a thermal storage system, which accumulates heat from the solar field in sunny hours to release it later for power generation. The receiver technology is a very important research topic in power tower development. Molten salt has been then applied in a receiver composed of vertically located tubes. The salt is then used for direct power generation or for heat storage.

In January 2011 the installed **nuclear** electricity capacity in the EU was 130 GWe, which contributed one third of the generated electricity in the EU. As of today the state of the art of commercial nuclear power reactors are of the third generation. The European Pressurized Water Reactor (EPR) is an evolution of the French N4 and German KONVOI reactor designs. Its electrical power is 1650 MW and the thermal power 4500 MW, i.e. the thermal efficiency is about 36-37%. The EPR is designed for a 60 year lifetime.

Geothermal resources can be classified in low-, medium- and high-enthalpy fields. Medium- and high-enthalpy resources imply the temperature range of 100-180°C, and above. These resources are exploited for power generation with and without heat cogeneration. In 2009 the installed geothermal power capacity achieved 9 GW_e generating around 60 TWh of electricity. This is less than 1% of the global electricity demand. Geothermal power potential is currently limited to tectonically active regions. Countries with high potential include Iceland, Indonesia, Philippines, New Zeeland and Japan among others. Different technologies are applied for the heat to power conversion. The less common are dry steam plants. In this case the naturally produced steam is dry enough to go through the turbine. Most geothermal power resources are based on a mixture of steam and hot water and require a single- or double-flash system to separate out the hot water, before the steam is routed to the turbine. Flash plants are the most common geothermal power plants. Finally, binary plants are applied together with low and medium-enthalpy geothermal fields. Current investment costs of geothermal power plants are typically around 2800 €/kW$_e$. O&M costs are around 3.5% of the investment cost. Power generation costs are roughly 65 €/MWh.

The global theoretical potential of **ocean energy** has been estimated between 20000 and 90000 TWh/year (as a reference, the world's electricity consumption is around 16 000 TWh/year). Tide and marine current resources represent estimated annual global potentials exceeding 300 TWh and 800 TWh per annum, respectively. Wave energy has an estimated theoretical potential of between 8 000 TWh and 80 000 TWh per annum. The theoretical potential of ocean thermal gradient (also known as OTEC) is estimated around 10 000 TWh per annum. The potential of salinity gradients is estimated at 2 000 TWh per annum. The main ocean wave conversion technologies are hydraulic or pneumatic power conversion systems including point absorber, overtopping terminator, the linear absorber or attenuator, the oscillating water column, the oscillating wave surge converter, submerged pressure differential. Tidal and open-ocean current energy conversion technologies make use of the large mass of moving water in tidal and other marine currents that contain kinetic energy that can mostly be captured by means of wind-turbine-like technology. Horizontal axis turbine, vertical axis turbine, and some non-turbine systems are among the technologies used. Furthermore, there are some ocean thermal energy conversion technologies developed. OTEC is the extraction of solar energy via a heat engine operating across the temperature difference between warm surface ocean water and cold deep ocean water. There are potentially three basic types of OTEC power plants: closed-cycle, open-cycle, and various blends of the two. All three types can be built on land, on offshore platforms fixed to the seafloor, on floating platforms anchored to the seafloor, or on ships that move from place to place. Finally, salinity gradient or osmotic conversion technologies have been developed, where the energy is retrieved from the difference in the salt concentration between seawater and river water. Two practical methods for this are reverse electro dialysis (RED) and pressure-retarded osmosis (PRO). Both processes rely on osmosis with ion-specific membranes.

Combustion **boilers** are widely used to generate steam for industrial applications and power generation. Fossil fuels, biomass, nuclear and solar energy, electricity - can be used to generate heat and steam. Boilers can be grouped into two broad categories: water-tube boilers and fire-tube boilers. In the water-tube boilers, Key design parameters to determine the boiler size and power are the output steam mass flow rate, pressure and temperature. In the industrialised countries, more than 50% of the industrial boilers use natural gas as the primary fuel and about 76% of the total boiler population is older than 30 years. The power of a boiler is determined by the required steam mass flow rate, pressure and temperature. The amount of input fuel depends on the fuel energy content and on the overall energy efficiency. New boilers running on coal, oil, natural gas and biomass can reach efficiencies of 86-88%, 89%, 90% and 70-80% respectively. Boiler efficiency can be improved by preventing and/or recovering heat loss. The construction of a large industrial steam generator can take between 22 and 48 months depending on the scope and framework. For a full-load steam system (86%-94% utilization), the fuel cost accounts for 96% of the total life-cycle cost while investment, operating and maintenance costs usually account for 3% and 1%, respectively. The cost structure clearly demonstrates that the energy efficiency is the main cost driver.

Combined heat and power (CHP), also known as cogeneration currently accounts for around 9% of global power generation. 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 fulfil 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. The investment costs of a gas-turbine CHP plant ranges from €650/kW$_e$ to €1050/kW$_e$, with a typical cost figure of €700/kW$_e$. The annual operation and maintenance (O&M) costs are approximately €30/kW$_e$. The investment costs of a combined-cycle (CCGT) CHP plant range from €770/kW$_e$ to €1260/kW$_e$ and more, with a typical cost figure of €900/kW$_e$. The annual O&M costs are approximately €35/kW$_e$. The investment costs of a fluidised-bed combustion (FBC) CHP plant based on coal ranges from €2100/kW$_e$ to €4200/kW$_e$ and more, with a typical cost figure of €2280/kW$_e$ and annual O&M costs of approximately €70/kW$_e$. The investment costs of a gas-engine CHP plant are in the range of €600–1400/kW$_e$, with a typical cost figure of €735/kW$_e$. Its annual O&M costs are about €175/kW$_e$. Much higher costs are quoted for fuel cell based CHP. The investment costs of biomass CHP plants are between €2100 and €4200/kW$_e$. The annual operation and maintenance cost (O&M) of the CHP plants is approximately €70/kW$_e$.

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. The increasing efficiency of the gas turbines and CCGT has provided another advantage to using CHP plants. The investment costs of anaerobic digesters with gas-engines for CHP are in the range of €2100 to €3500/kW$_e$, with annual O&M cost of about € 210/kW$_e$.

In Germany, the growth of biomass-based CHP amounted to 23% per year in the period 2004-2008. Biogas anaerobic digesters are usually associated to gas-fired engines for heat and power generation. Biomass CHP plants have capacities ranging from a few MW$_e$ up to 350 MW$_e$. Small and medium-size CHP plants are usually sourced with locally available biomass. Large CHP plants and coal/biomass co-firing power plants require biomass sourcing from a wide region and/or imported wood or forestry residues. Biomass CHP plants are mature technologies. CSP plants can be used in cogeneration. One approach under investigation in parabolic trough power plants is to combine power generation and thermal seawater desalination. The desalination plant would use the heat in the condenser of the Rankine cycle. This option could emerge as attractive; especially taking into account that most potential application sites for CSP suffer fresh water shortage. Nuclear cogeneration is since long an established method which can provide large amounts of practically CO2 free heat. In 2010 there were 420 reactor years (RY) of experience in nuclear process heat production, and 500 reactor years (RY) of nuclear district heating. For industrial heating processes nuclear heat is mainly used in the paper and pulp industry. District heating from nuclear power is well established in Eastern Europe. As an example of the latest technology is the study on the Loviisa NPP to provide district heating for Helsinki's 1 million inhabitants used. It is the most recent example of a large scale NPP studied for district heating in a market economy.

Carbon Capture and storage is generally understood as consisting of three major steps: carbon dioxide capture from flue/fuel gases; CO_2 transport; and CO_2 storage. Currently there are three main methods for capturing CO_2 in power plants: Post-combustion, pre-combustion and oxy-fuel combustion capture. Among all capture methods, CO_2 scrubbing techniques are the most mature. The efficiency of both oxy-fuel and pre-combustion capture depends significantly on the energy needed for oxygen production. The net efficiency of commercial SCPC plants equipped with oxy-fuel capture or post combustion capture is estimated at about 35% LHV. Transport technology of Carbon dioxide is mature, since CO_2 is already transported for commercial purposes by road tanker, by ship and by pipeline. Although each of these methods is practical, there is a need for scaling up in order to accommodate for the future quantities of CO_2 to be transported from source to storage site that will be considerable. Various technical options for the long-term storage of CO_2 are being researched. Geological storage is by far the cheapest and most promising option and industrial geological CO_2 storage projects have already been initiated in Europe and worldwide. Compressed CO_2 is already injected into porous rock formations by the oil and gas industry, e.g. for EOR, and is proven at a commercial scale. Due to its possible environmental implications, the current option of CO_2 storage deep in the oceans is no longer considered an option. Mineral carbonation is an alternative for storing CO_2 in materials. However, due to the large amounts of energy and mined minerals needed, it is not likely to be cost effective. Retrofitting an existing power plant with CCS technology is currently a quite costly option that can result to a overwhelming efficiency penalty. Efficiency losses up to 14% and investment cost in the order of more than €700/kW have been reported. Despite the fact that retrofitting technologies are not yet commercially viable, fossil fuel-based power plants currently under commissioning are designed to enable CCS retrofit (capture-ready plants) as soon as the technology will become commercial and marketable, in order to avoid the lock-in of CO_2 emissions.

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1 POWER GENERATION

In Europe, the total electricity generation capacity is about 804 GWe, of which 29% is from nuclear power, 22% is based on natural gas, 18% is based on hard coal and 10% on lignite (ETSAP, Coal Fired Power 2010) (ETSAP, Gas Fired Power 2010). Fossil fuel power generation is the biggest contributor to CO_2 emissions and any gains in conversion efficiency would translate to substantial CO_2 savings. For instance, each % point efficiency increase is equivalent to about 2.5 % reduction in tonnes of CO_2 emitted (ETSAP, Coal Fired Power 2010).

1.1 ADVANCED FOSSIL FUEL POWER GENERATION

The main fossil fuel based electricity generation technology in the world and in the EU is pulverized coal (PC) combustion. The majority of pulverised coal plants are more than 15 years old and operate with sub-critical steam parameters and efficiencies between 32 - 40% (lower heat value basis). Upgrading low-efficiency fossil plants should be a high priority in the future. Super-critical (SC) plants with steam conditions typically of 540^{o}C and 250 bar have been in commercial operation for a number of years and have efficiencies in the range 40 – 45%. However, if the best available technologies were to be used, as, for example, "advanced super-critical" plants with steam conditions up to 600ºC and 300 bar, it should be possible to reach net efficiencies between 46 – 49%. Reaching these steam conditions demands successive reheating cycles and stronger and more corrosion resistant steels that are inevitably more expensive than standard boiler steels. Nevertheless, the achieved overall efficiency improvement easily counterbalances additional cost and on-site energy consumption. There is a limit to the benefit of increasing steam pressure at a given temperature in that a reduced volume of steam leads to higher rates of leakage as the steam passes through the turbine. Amongst numerous other factors, site specific requirements such as geographical location, i.e. inland or coastal, availability of cooling water, as well as ambient temperature are also key factors determining the actual efficiency achieved.

Operating conditions strongly influence the mean efficiency recorded during operation. The measured efficiency of the plant is different from the design efficiency, as operation rarely complies with ideal conditions (due to fouling, slagging, de-superheating, non-ideal condenser conditions, blow-down, etc.), and as the characteristics of the solid fuel used never comply exactly with the characteristics of the 'design solid fuel' (calorific value, ash content, etc.). Ageing of a normally maintained plant (fouling, slagging, erosion, leaks, etc.) also leads to deterioration in efficiency over time.

Other aspects that influence efficiency are:

• the technology used: an IGCC, for example, consumes essentially more auxiliary energy (for the air separation unit, gas treatment and compressor) than a conventional boiler, even with flue-gas treatment

• the level of pollution control: advance FGD consumes more energy, and generally pollution control measures have a detrimental effect on efficiency

• the design of the auxiliaries: boiler auxiliaries have to be over-dimensioned to withstand all variations in parameters compared to their design values (i.e. for possible leaks, alternative fuels, start-up needs, redundant systems, etc.). These technical options lead to changes in energy consumption from that under normal conditions and with the fuel they were designed for.

• Boiler efficiency. For a clean and new boiler, an efficiency level of around 86 - 95% (LHV) is currently recorded for solid fuel and cannot easily be increased. The main losses stem from flue gas waste heat at stack, unburned carbon-in-ash, and waste heat and from heat radiation losses. The effect of fuel is also important. Even assuming that the boilers have identical performance (i.e. same ambient and flue-gas temperature, same excess air, etc.), different boiler efficiencies are still obtained, and these depend on the fuel, for example (LHV basis):

- hard coal: 95% efficiency
- lignite: 92% efficiency
- low grade lignite: 86% efficiency.

1.1.1 Open Cycle Steam Turbine Plant

In a pulverised coal-fired steam power plant, coal is milled and burned with air in tall boilers that provide for complete burnout and efficient heat transfer. Radiant and convective heat is transferred to the boiler walls' pipes that carry pressurised water. In a few heating stages (single or double reheating), water is converted into superheated steam. The latter is directed to a steam generator which converts its thermal into mechanical energy and finally electricity (see Figure 1-1). Natural gas or fuel oil may also be used for the start-up phase of a pulverized coal-fired power plant, followed by gradual phase-in of coal (ETSAP, Coal Fired Power 2010). Super-critical pulverised coal (SCPC) power plants use super-critical steam as the process fluid to reach high temperatures and pressures, and efficiencies up to 46% (lower heating value, LHV). New ultra-super-critical (U-SCPC) power plants may reach even higher temperatures and pressure, with efficiency up to 50%. Several years of experience with good availability have already been achieved, for example with Unit 3 of the Nordjyllandsvæket USC combined heat and power plant near Aalborg in Denmark, where 47% electrical efficiency is achieved with an output of 410 MW and steam conditions of 582^{o}C and 290 bar. The plant started operation in 1998 and benefits from the availability of seawater to provide cooling. High electrical generation efficiency of 43% has also been achieved with the more difficult to handle lignite (brown coal) at the 1 012 MWe Niederaussem K plant in Germany. Future USC plants are planned to use 700 °C and 350 bar or higher, which should give net efficiencies of the order of 50 – 55% (JRC-SETIS 2009).

An indicative process flow diagram is presented in Figure 1-1. The coal is burned in a tower boiler. NOx emissions are controlled by a combination of combustion measures and a selective catalytic reduction unit. Electrostatic precipitators collect fly ash, and a wet flue gas desulphurisation unit de-sulphurises the emerging flue gas, which is then sent to a stack. The boiler converts water to superheated super-critical steam in a single pass. The steam is expanded in an ultra-super-critical turbine, reheated in the boiler, further expanded, reheated a second time, expanded once more, then finally condensed and returned as water to the boiler. The condenser can be cooled with the use of induced or forced-draft cooling towers, dry cooling tower or directly air cooled radiators where fresh water sources are limited and, where economically and environmentally possible, by the use of cooling water from the ocean, or a lake or river, or a cooling pond, instead of a cooling tower. Some steam is taken from the turbine to serve condensing heat exchangers to heat the district heating water. Steam conditions are in the range of 300 bars and 600°C. This selection of main steam parameters minimizes fuel use, cost and emissions while keeping risk as low as possible for a state of- the-art plant (Henderson 2007).

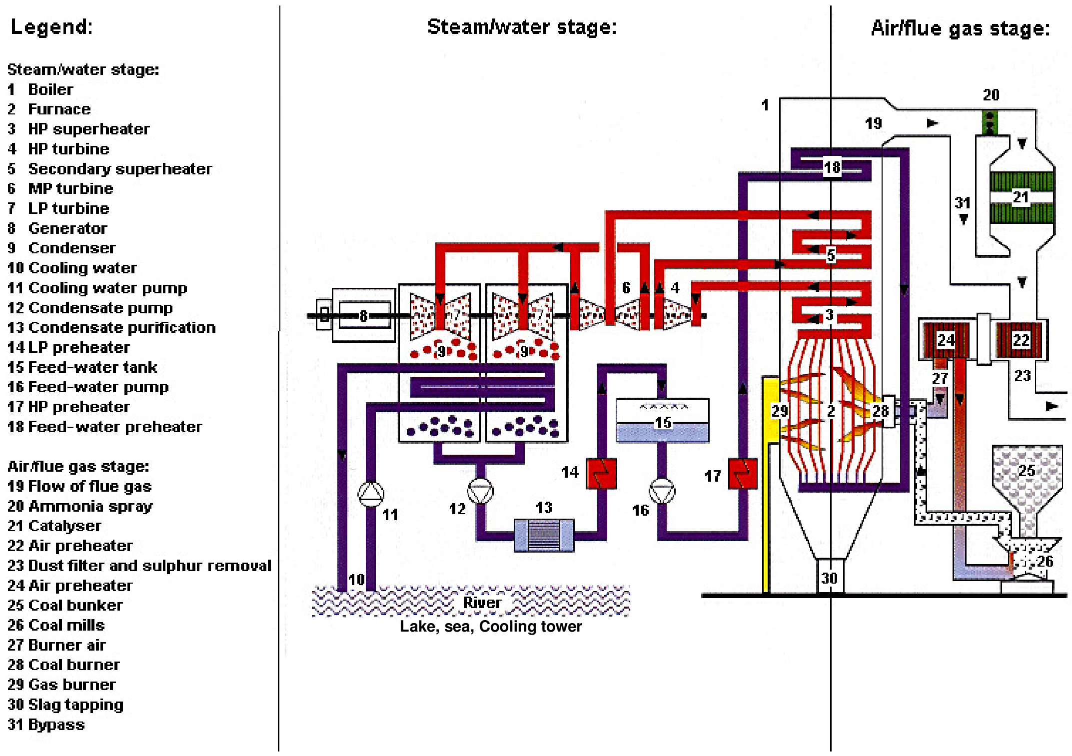

Figure 1-1: Possible process flow diagram of a power plant (IPPC 2006)

Low-NOx burners and, if requested by environmental regulations, selective catalytic reduction (SCR) systems are applied to reduce the NOx emissions to the required level. Other environmental impacts relate to the ashes produced in the case of coal combustion Waste can be minimised both prior to, and during, coal combustion. Coal cleaning prior to combustion is a very cost-effective method of providing high quality coal. It reduces power station waste, SOx emissions, and increases thermal efficiencies. The residual waste can then be reprocessed into construction materials (WCI, 2004).

Materials for state-of-the-art steam turbines and boilers can withstand maximum operating temperatures of 600-610°C for primary steam, and 610–620°C for reheated steam, and a maximum pressure of 30 MPa (Susta, 2008). More than 570 SCPC or U-SCPC units are in operation, under construction, or planned worldwide (Figure 1-1: Possible process flow diagram of a power plant (IPPC 2006)) totalling some 430 power plants (2008), with sizes ranging from 200 MWe to 1300 MWe and a total capacity in excess of 330 GWe. The majority of these units operate at a steam pressure and temperature (i.e. below 24MPa/595°C) that are compatible with the use of allferritic steel for thick-wall boiler components. Further temperature increases require the use of Ni-based super-alloys and new designs. It is anticipated that above 650°C super-alloys will replace traditional ferritic steels for steam turbine rotors. Because of the increased thermal expansion coefficients of these materials compared to ferritic steels, thermal stresses in forgings and castings become an important issue during start-up and load cycling, and rotor axial expansions require new design approaches (PC, 2004). Based on ongoing developments, conditions of 35MPa and 720-760°C – with net LHV efficiency above 52% might be designed and tested in the next decade.

In the last few years, the investment cost of the SCPC plants increased rapidly due to high prices of steel, other materials, and equipment. Around the year 2000, the specific investment cost was approximately €1100/kWe (2010 euros). In 2008, the investment cost of state-of-the-art SCPC power plants was approximately €1600/kWe. As the SCPC is a mature technology, its investment cost may decrease moderately based on technology learning. The following costs are predicted over the next two decades: €1400/kWe in 2020, and €1300/kWe in 2030 (based on learning effects) (ETSAP,2010). For (U-)SCPC plants, the O&M cost is estimated at €62/kWe per year in 2010, €56/kWe in 2020, and €51/kWe in 2030 (ETSAP,2010). It should be said that the current global economic crisis is resulting in significantly lower material prices and lower demand for new capacity. This may result, in turn, in lower investment costs and prices of power technologies.

In accordance with the target efficiency of the "Advanced (700 C) PF Power Plant"AD700 project, it is assumed that technological learning will entail slow efficiency gains for U-SCPC, namely 50% (LHV) in 2020 (ETSAP, Coal Fired Power 2010). With the elevated steam conditions, advantage will have to be taken of advanced turbine blading technology and state-of-the-art condenser configurations to achieve very low turbine exhaust pressures, thereby maximising the pressure drop across the turbine to provide maximum power generation. In addition, it has the potential to provide large quantities of low pressure process steam extracted from the turbine for district heating, industrial use or an on-site CO2 capture plant. The main aim of the THERMIE 700^{o}C steam coal power plant project is to make the jump from use of steels to nickel-based super alloys for the highest temperatures in the steam cycle which should enable efficiencies in the range of 50 – 55% to be achieved. When a 700^{o}C steam coal power plant will become a reality is not known (JRC-SETIS 2009).

1.1.2 Open Cycle Gas Turbine Plant

Natural gas fired open cycle gas turbine (OCGT) plants are used to meet peak-load demand and offer moderate electrical efficiency of between 35% and 42% (lower heating value, LHV) at full load. Their efficiency is expected to reach 45% by 2020 (ETSAP, Gas Fired Power 2010). Gas turbines powered with liquid fuels (not as the back-up fuel) are very rarely applied in Europe. This is due to the high costs of such fuels, mainly light distillate oil; and the stress imposed by liquid fuels on gas turbine blades and rest systems compared to natural gas. Applications are very rare and they are used only in those cases where a natural gas supply does not exist. Their thermal efficiency is then between 30 and 40% (IPPC 2006). Two types of liquid fuel-fired gas turbines are currently applied: heavy duty gas turbines and gas turbines derived from aeroplane engines, so-called aero derivatives. Gas turbines (GT) can operate with a wide range of liquid fuels, such as residual fuel naphtha. Gas turbines in general and aero derivatives in particular run on light distillate fuel oil or on kerosene. For recent designs of turbines, which have high turbine inlet temperatures, the manufacturers' specifications for fuel supplies are very stringent. They stipulate the physical and chemical properties needed in order to meet the equipment demands and the environmental standards, particularly with regard to metal contaminants (sodium, potassium, lead, vanadium, and calcium), sulphur and ashes

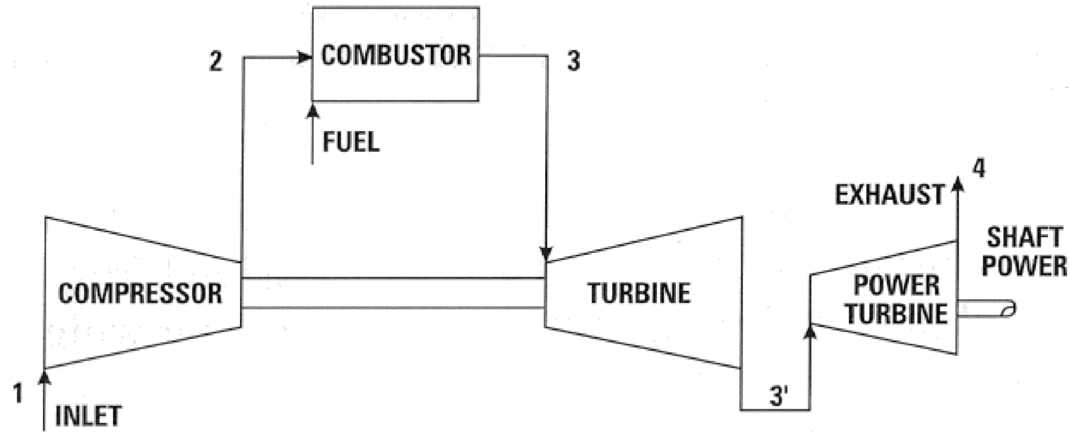

Figure 1-2: Gas turbine schematic diagram (FIU 2011)

As shown in Figure 1-2, simple OCGT plants consist basically of an air compressor and a gas turbine aligned on a single shaft connected to an electricity generator. Filtered air is compressed by the compressor and used to fire natural gas in the combustion chamber of the gas-turbine that drives both the compressor and the electricity generator. Almost two-thirds of the gross power output of the gas-turbine is needed to compress air, and the remaining one-third drives the electricity generator. By means of an axial compressor, pressurised air is driven, into the combustion chambers, where the fuel injectors are connected. During the combustion reaction, the gas temperature rises, and at between 1000 and 1350°C it is introduced into the turbine. These hot gases are depressurised in the turbine, which simultaneously drives both the air compressor and the alternator, which in turn generates electricity. In the ‘open cycle’ configuration, the combustion gases are released directly into the atmosphere at a temperature of >450°C (IPPC 2006).

The investment cost of OCGT plants is approximately €450/kWe. Modest cost reductions are also expected for OCGT plants, namely €425/kWe in 2020, and €400/kWe in 2030. The annual operation and maintenance costs of OCGT plants are estimated at 4% of the investment costs per year. Generation costs of OCGT are around €100–115/MWh (typically, €1500/MWh), of which €20–35/MWh is for the fuel. In the OCGT plants, the fuel cost may be up to 50% higher than in CCGT as the efficiency is about two-thirds that of a combined cycle. However, the main reason for the OCGT high generation cost is the low load-factor of the peak-load services, typically 10% vs. 50-60% for the CCGT plants. (ETSAP, Gas Fired Power 2010).

1.1.3 Combined Cycle Combustion Plant

Combined Cycle combustion systems employ a combination of a gas turbine and a steam turbine, sometimes on a single shaft. In the gas turbine (see Figure 1-3) air, after compression, is heated by combustion of the injected fuel. The highest gas turbine inlet temperatures are currently approaching 1400°C (Henderson 2007). The added energy is exploited by expansion of the hot product gases through an expander, turning the rotor. The rotor directly drives the compressor and the generator. Exhaust gases leaving gas turbines are typically at a temperature of 550-600°C, and are used for the production in a heat recovery boiler of steam at different pressures for expansion through the steam turbine (see Figure 1-3) for generation of additional power (Henderson 2007). Reheat may also be used in the steam cycles of combined cycles, depending on cost-effectiveness. Natural gas combined cycle plant demonstrate higher efficiencies than the current coal plants, because of the higher working temperature attainable in gas turbines that allows a combined cycle operation and low in-plant power consumption. Furthermore, there is no need for solids handling or SO_2 or particulates emission control systems.

In terms of environmental impact, NO_x emissions are controlled by control of fuel/air mixing and, in some plants, by an SCR unit in the heat recovery boiler. There are other means of obtaining high gas turbine efficiencies, such as using reheat or cooling the air at inlet or between stages of compression (Henderson 2007). Combined cycle combustion systems can be used for liquid fuels in the same way in which they are used for other fuels. Heavy or light fuel oil is sometimes used for additional firing in heat recovery boilers or as a supplementary fuel in natural gas-fired plants, where it can also be used as back-up fuel (IPPC 2006).

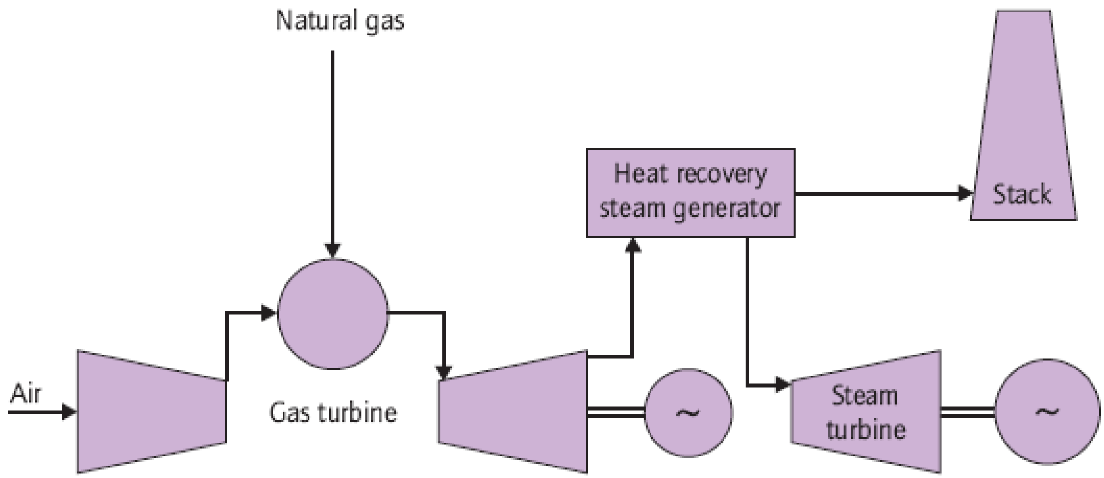

Figure 1-3: Possible process flow diagram of a Natural Gas fired Combined Cycle power plant (Henderson 2007)

A more detailed configuration of a state of the art CCGT plant is shown in Figure 1-4 (Henderson 2007).

CCGT plants consist of compressor/gas-turbine groups – the same as the OCGT plants – but the hot gas-turbine exhaust is not discharged into the atmosphere. Instead it is re-used in a heat recovery steam generator (HRSG) to generate steam that drives a steam-turbine generator and produces additional power. Gas-turbine exhausts then leave the HRSG at about 90°C and are discharged into the atmosphere. CCGT plants commonly consist of one gas turbine and one steam turbine. Approximately two thirds of the total power is generated by the gas turbine and one-third by the steam turbine. Large CCGT power plants may have more than one gas turbine.

In the gas turbine, air is compressed in an axial flow, rotating compressor then natural gas is combusted in it, raising the temperature to 1140°C. The hot product gases are expanded through a high pressure turbine, additional natural gas is added and burnt, raising the temperature again (to 1280°C), and the gases are further expanded through the remaining stages of the turbine. The expanding gases cause the turbine to rotate, and the turbine directly drives the compressor and a generator. The hot turbine exhaust gases are used to raise superheated and reheated steam in a heat recovery steam generator (HRSG). The emerging cooled gases (at around 100°C) are then sent to the stack.

The other main component of the combined cycle system is a sub-critical reheat steam turbine, which is also coupled to the generator. The steam turbine utilises steam from the HRSG at three pressure levels (107 bar/566°C; 25 bar/560°C; 4 bar/saturated). The steam is expanded in the high pressure turbine, reheated in the HRSG, then expanded again, with additional steam from the HRSG, before being condensed and returned as water to the boiler. Output from the gas turbine is varied by adjusting the compressor's inlet guide vanes. The steam turbine output also decreases as less heat is available for steam temperature rising. The steam turbine cycle uses an air-cooled condenser.

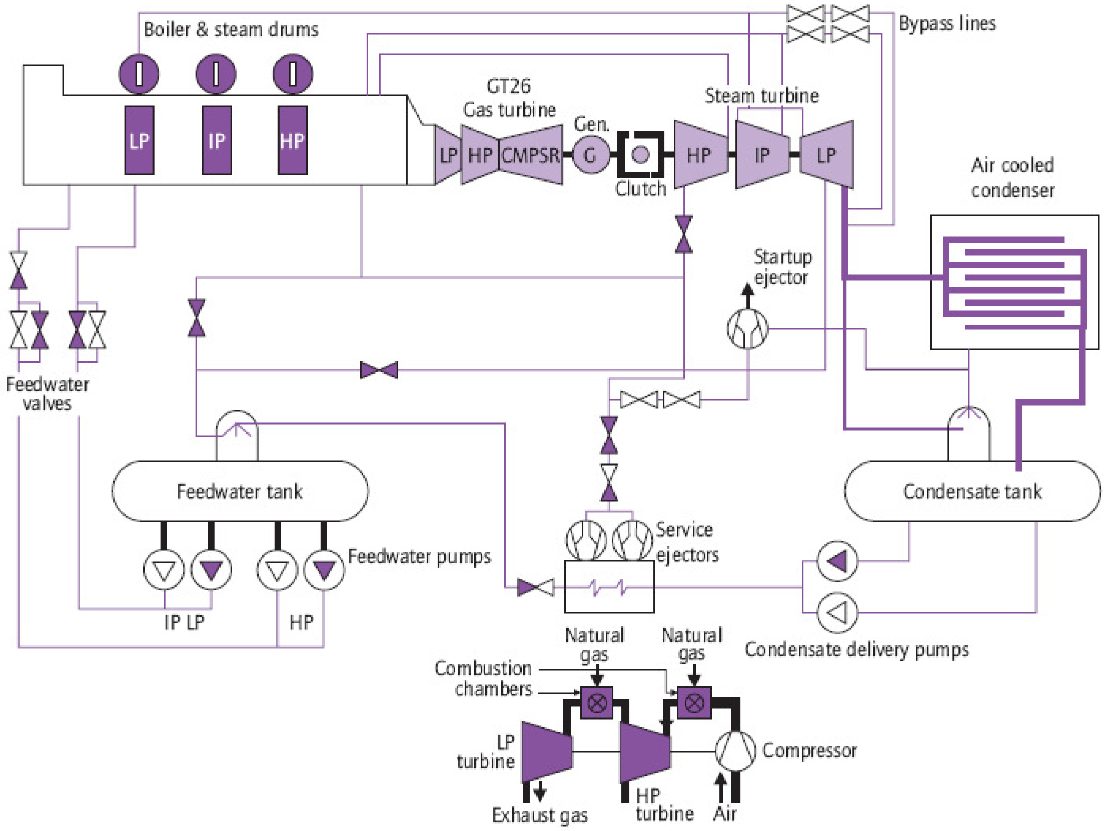

Figure 1-4: Natural gas-fired combined cycle plant overall configuration (Henderson 2007)

Figure 1-5 shows the efficiency of CCGT plants compared with pulverised coal (PC) power plants as a function of the maximum cycle temperature (ETSAP, Gas Fired Power 2010). Current super-critical coal-fired power plants may reach a full-load efficiency of 45–46% (2010) while the current full-load efficiency of CCGT power plants is close to 60%. Technological developments aim to increase the CCGT efficiency by raising the gas turbine inlet temperature and simultaneously decreasing investment cost and emissions.

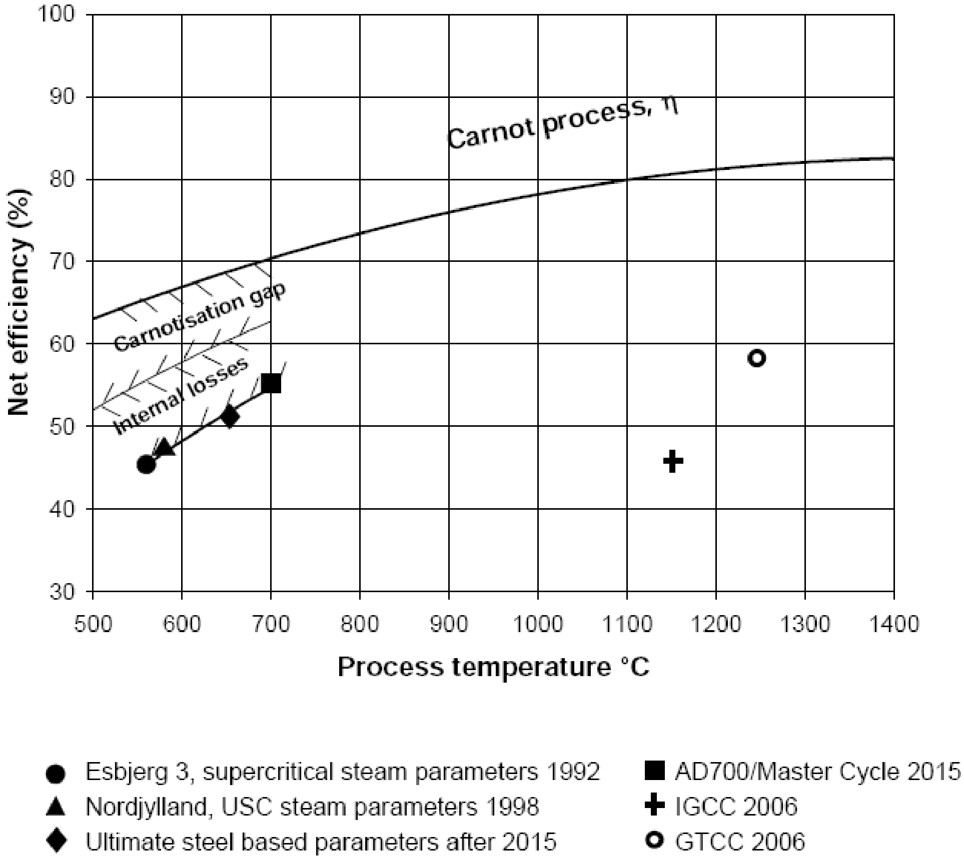

Figure 1-5: Efficiency of GTCC and PC power plants vs. gas and steam temperature (ETSAP, Gas Fired Power 2010)

The efficiency as a function of the gas turbine inlet temperature is shown in Figure 1-6. A CCGT plant with a 1700°C class gas-turbine may attain an electrical efficiency of 62–65% (LHV) (ETSAP, Gas Fired Power 2010). Thus, the CCGT efficiency is expected to increase from today's 52%–60% to a maximum of 64% by 2020. OCGT efficiency is also expected to rise from its current 35%–42% (LHV) to 45% by 2020. (ETSAP, Gas Fired Power 2010).

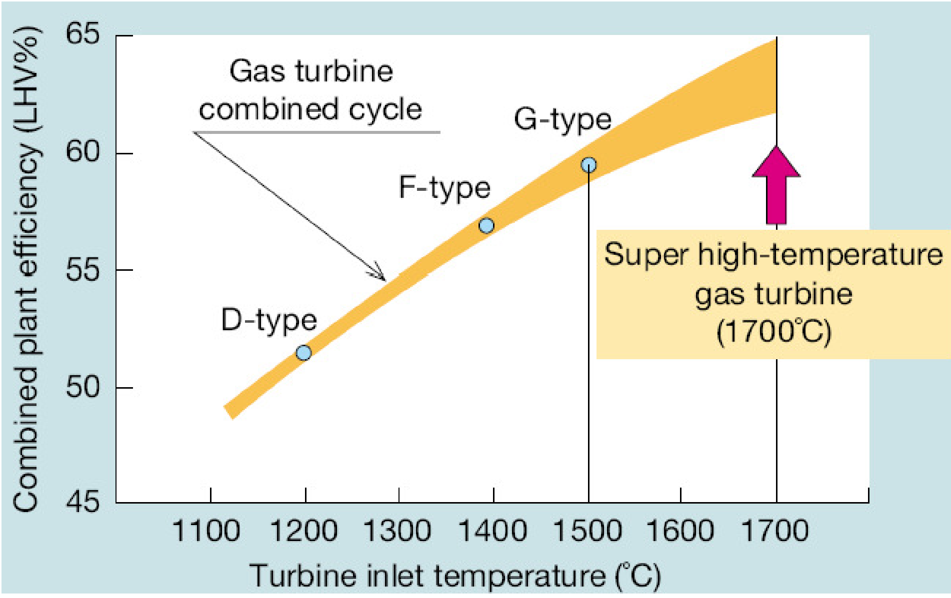

Figure 1-6: CCGT efficiency (ETSAP, 2010)

Over the last few decades, impressive advancement in technology has meant a significant increase of the CCGT efficiency by raising the gas-turbine inlet temperature, with simultaneous reduction of investment costs and emissions. The CCGT electrical efficiency is expected to increase from the current 52–60% (LHV) to some 64% by 2020. CCGT plants offer flexible operation. They are designed to respond relatively quickly to changes in electricity demand and may be operated at 50% of the nominal capacity with a moderate reduction of electrical efficiency (50–52% at 50% load compared to 58–59% at full load). In general, because of the lower investment costs and the higher fuel (natural gas) cost vs. coal-fired power, CCGT plants are lower in the merit order for base-load operation, although the competition also depends on local conditions, variable fuel prices and environmental implications (ETSAP, Gas Fired Power 2010). .

Such a plant can generate power from natural gas with a net LHV efficiency of as high as 52%. NGCC projects are lower in investment requirements than CCGT. The cost of gas turbines combined cycle using natural gas as fuel has a specific capital investment of the order of 600 €/kW (Technology Map, 2009). The turnkey power plant contract accounts for approximately 50% of this. Gas turbine combined cycle plants are also capable of short construction times because equipment is not project specific (except 50Hz / 60 Hz machines) and much of it can be delivered to site pre-assembled. Construction time can be less than 2 years. Availability is high, at 95%. Apart from the uncertainty about future CO_2 prices, a disadvantage to the economics of these types of plants lies in their strong dependence on fuel costs, which form a very large proportion of the electricity production cost. This leaves them vulnerable to the greater volatility in gas prices than those of coal. However, efficiencies are gradually rising as gas turbines are developing and the technology looks set to remain one of the cornerstones of utility power production in many parts of the world with access to natural gas (Henderson 2007).

Due to the high price of materials and equipment and the increasing demand for new CCGT plants, the investment cost of CCGT power plants has been increasing almost continuously from some €710/kWe in 2002 to €820/kWe in 2009 (costs quoted in 2008 US dollars) (ETSAP, Gas Fired Power 2010). At present, if compared with the 2008 peak cost, the CCGT investment costs might be slightly declining because of the reduction of material costs and the low demand for new capacity due to the ongoing economic crisis. While technology learning is not expected to significantly reduce the investment cost of mature technologies, technical developments in CCGT plants may still drive cost reductions from today's €820/kWe to €720/kWe in 2020, and to €640/kWe in 2030 (ETSAP, Gas Fired Power 2010). The annual operation and maintenance costs of CCGT plants are estimated at 4% of the investment costs per year. The generation costs of CCGT range between €46 and €56/MWh (typically, €52/MWh), of which €20–30/MWh is for the fuel. (ETSAP, Gas Fired Power 2010).

1.1.4 Integrated Gasification Combined Cycle Plant

The basic principle of Integrated Gasification Combined Cycle (IGCC) plant is shown in Figure 1-7. There are many possible configurations because gasifier designs vary significantly and IGCC has a large number of process areas. Gas cleaning in IGCC is typically affected by dry removal of solids from the raw gasifier product gas followed by cold wet scrubbing. Deep cleaning is necessary to protect the integrity of the gas turbine, but it also results in emissions of particulates and SO2 being very low. Totally dry gas clean-up may eventually be applied, but is not yet reliably demonstrated. There are three general types of gasifier: entrained bed, moving bed (also confusingly referred to as fixed bed), and fluidised bed. IGCCs have usually been based around entrained gasifiers because of their fuel flexibility, their production of high pressure steam, and the lack of tars in the product gas. Entrained gasifiers operate in slagging mode, and most are oxygen blown. In an IGCC, the oxygen production plant can take its compressed air supply from the gas turbine compressor or from separate motor driven compressors or a combination of both. The latter is favoured for future designs as it gives more rapid start-up and greater operating flexibility, while maintaining the efficiency advantage of gas turbine air extraction (Henderson 2007)

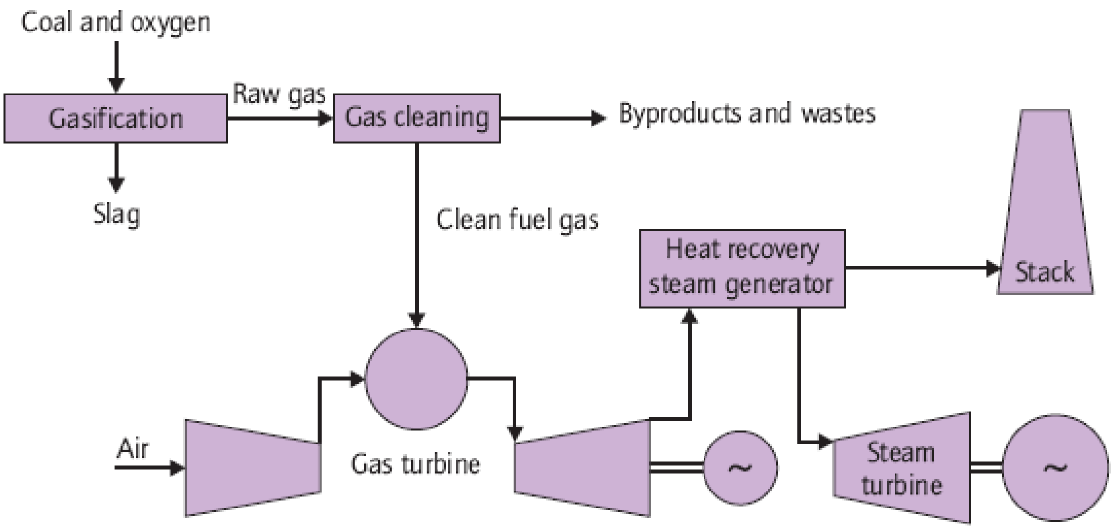

Figure 1-7: Possible process flow diagram of an Integrated Gasification Combined Cycle power plant (Henderson 2007)

IGCC systems with cold gas cleaning are able to achieve relatively good NO_X emission values. This is due to the fact that fuel-bound nitrogen is almost removed in the scrubber of the cold gas cleaning section. Thermal NO_X formation in the combustion chamber of the gas turbine is suppressed by saturation of the fuel gas with steam prior to combustion and by dilution with nitrogen from the air separation unit. These emission reduction measures result in NO_X emissions of less than 25 mg/Nm^3 at an oxygen content of 15% in the flue-gas. IGCC also reduces significantly the amount of particulates, SO_2 (5 mg/Nm^3), waste water and CO_2 discharged. IGCC offers thermodynamically favourable conditions of high pressure; high concentration of contaminants and low volumetric flows of syn-gas which is as little as 1/100 of the combustion products. This allows economical deep cleaning of sulphur and particulates. The majority of the pollutants are partitioned and captured in the IGCC gas cleaning process. The reducing conditions in gasification strongly favour conversion of fuel mercury to its elemental form. Elemental mercury can be reliably and easily removed by sulphinated activated carbon as has been already achieved at one site (IPPC 2006).

The investment cost of coal-based IGCC plant is high compared to pulverised coal, i.e. €2600/kWe (Power Engineering, 2009). Technological learning is expected to have a more important impact on future IGCC investment costs. Projections suggest a decline from some €2600/kWe in 2010 (70% more than PC power) to €2000/kWe in 2020 (40% more than PC power) and to €1600/kWe in 2030 (20–25% more than PC power). Technology learning effects rely on the future availability of high-capacity gasifiers, more efficient gas cleaning systems, and high-efficiency gas turbines. The operation and maintenance (O&M) cost (expressed in €/kWe per year) is estimated at 4% of the investment cost per year for both SCPC and IGCC plants.

For IGCC plants, the O&M cost is estimated at €148/kWe per year in 2010, €112/kWe in 2020, and €88/kWe in 2030) (ETSAP,2010). IGCC has a smaller cost differential between CO_2 capture and non-CO_2 capture than PC combustion. The cost of IGCC without capture is still higher than PC. High pressure (in the range 30 – 70 bar) also reduces syn-gas clean-up costs and should save on compression costs for eventual carbon dioxide capture. However, on the other hand, this complicates coal feeding that could have a negative impact on fuel flexibility. IGCC with CO_2 capture capability has yet to be demonstrated and unlikely to be ready for commercialisation until 2020 (JRC-SETIS 2009).

Eight IGCC plants in US and Europe use coal or pet-coke. Another seven IGCC plants, four of which are in Italy, use residual oil (Higman, 2008). Integrated gasification combined cycle (IGCC) has been successfully demonstrated at two large-scale power plant demonstration facilities in Europe (Buggenum-NL and Puertollano-SP, see Figure 1-8). Designed as demonstration plants, they have a relatively small capacity (250–300 MWe). Their efficiency varies from 39% to 45% (LHV), which is comparable to state-of-the-art pulverised coal-fired power. The IGCC specific SO_2 emission is very low, i.e. ≤ 0.6 g/kWh (98–99+% desulphurisation), and the same applies to NOx (0.24– 0.40 g/kWh) and particulate matter (0.005–0.02 g/kWh) (ETSAP, Coal Fired Power 2010).

The IGCC plant can more easily attain very low levels of SO_2 and NO_x emissions than an ultra-SCPC plant. Low-NOx burners and, if requested by environmental regulations, selective catalytic reduction (SCR) systems are applied to reduce the NOx emissions to the required level. Other environmental impacts relate to the ashes produced in the case of coal gasification. (ETSAP, Coal Fired Power 2010). With complete gasification of coal, the ratio of power output between gas turbine and steam turbine will be around 55 – 45 % and the overall efficiency around 42 %. High temperature entrained flow gasification avoids tar related problems and increases gasification rate, allowing better matching with modern high capacity gas turbines that achieve high efficiencies (2009, Technology Map).

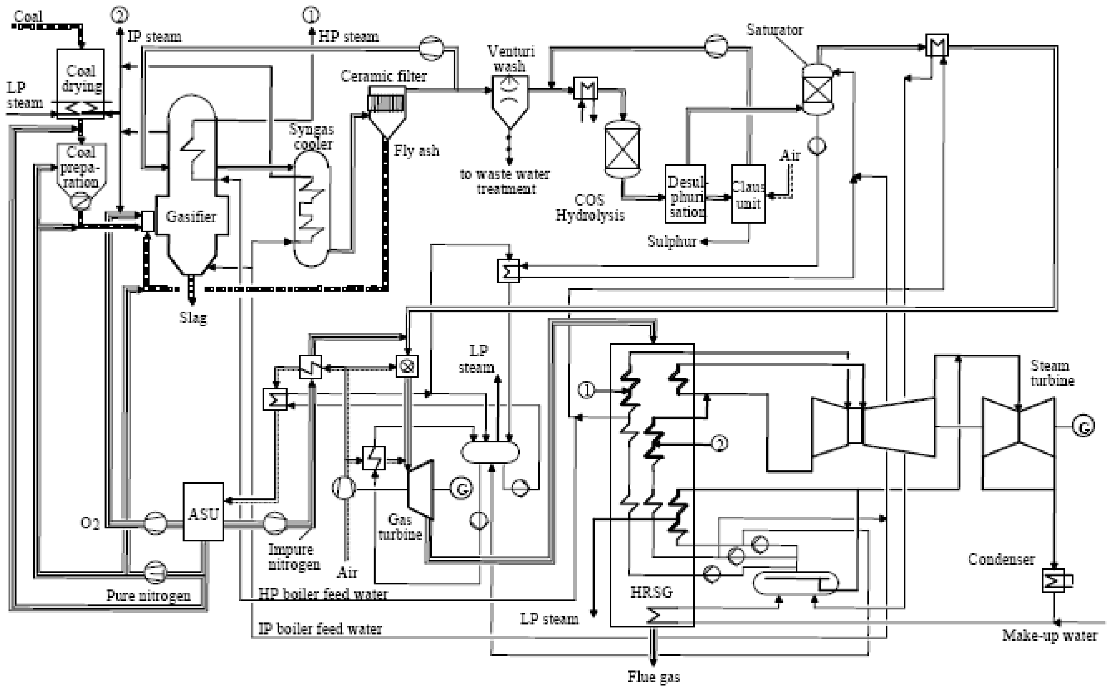

Figure 1-8: Flow sheet of an IGCC power plant operated in Puertollano-SP (IPPC 2006)

With regard to coal-based IGCC, it is assumed that these plants may have a net generating efficiency of 46% in 2010 (equal to SCPC plants). However, more learning potential for IGCC may result in a higher efficiency in 2020 (52%, LHV). IGCCs can take advantage from advances in gas turbine and CCGT systems that have been developed for natural gas.

The technology is ready for commercial exploitation. Further into the future, IGCC with hybrid fuel cell, gas turbine and steam turbine could conceivably reach 60 % efficiency (JRC-SETIS 2009).

1.1.5 Fluidised Bed Combustion

Fluidised bed coal combustion uses a continuous stream of air to create turbulence in a mixed bed of inert material and coarse fuel ash particles. At suitable gas velocities, the particles remain suspended and move about freely or become entrained in the gas stream. In this state they behave like a fluid and the bed becomes fluidised. When fuel is added to a hot fluidised bed, the constant mixing of particles encourages rapid heat transfer and good combustion. It also allows a uniform temperature to be maintained within the combustion zone. Heat generated is recovered by in-bed water tubes (with a BFBC boiler), water-walls, super-heater/re-heater sections, economiser and others. Flue gases leaving the combustion system are cleaned of solid and gaseous pollutants and then discharged into the atmosphere (Wu 2006).

FBC offers a number of advantages when compared to PCC including:

- Moderate operation temperatures (800 – 900)^{o}C, which however need to be kept below a certain level (1000^{o}C) in order to avoid ash melting and the formation of slag;
- increased heat transfer rate due to the scrubbing action of the moving particles on the immersed water tubes;

- substantial bed thermal capacity; this enables operation with fuels of wide margin of ash and moisture content, including low-quality fuels with a high ash or moisture content as well as mixed fuels;
- reduced NO_X formation because of the low temperature of operation;
- over 90% combustion SO_2 capture with the addition of suitable sorbent in the bed e.g. limestone or dolomite.

Although growth in the coal-fired power generation capacity using FBC between 1985 and 1995 had been significant, it still represented less than 2% of the world total (Wu 2006). This may be attributed to some disadvantages this technology demonstrates including:

- the relatively small scale of commercially proven operation compared with pulverised coal combustion;
- the relatively large amounts of solid residues generated (with sorbent addition), some of which require special measures for disposal;
- a higher carbon-in-ash levels than those from pulverised coal combustion;
- an increased N_2O formation (with coal/coke or similar fuels) due to the lower combustion temperatures.

FBC can be divided into 4 different types. In terms of the fluidising gas velocity, FBC can be divided into two groups: bubbling fluidised bed combustion which takes place at low gas velocities; and circulating fluidised bed combustion which occurs at higher gas velocities. In terms of operating pressure, there are also pressurised bubbling fluidised bed combustion and pressurised circulating fluidised bed combustion (Wu 2006).

Circulating Fluidised Bed Combustion

Circulating beds use a high fluidizing velocity, so the particles are constantly held in the flue gases, and pass through the main combustion chamber and into a cyclone, from which the larger particles are extracted and returned to the combustion chamber. Individual particles may recycle anything from 10 to 50 times, depending on their size, and how quickly the char burns away. Combustion conditions are relatively uniform through the combustor, although the bed is somewhat denser near the bottom of the combustion chamber. There is a great deal of mixing, and residence time during one pass is very short. (Wu 2006).

CFBCs are principally of value for low grade, high ash coals which are difficult to pulverise, and which may have variable combustion characteristics. It is also suitable for co-firing coal with low grade fuels, including some waste materials. The direct injection of limestone into the bed offers the possibility of SO_2 removal without the need for flue gas desulphurisation. Fuel flexibility is often mentioned in connection with FBC units. However, it should be noted that once the unit is built, it will operate most efficiently with whatever design fuel is specified. The design must take into account ash quantities, and ash properties. While combustion temperatures are low enough to allow much of the mineral matter to retain its original properties, particle surface temperatures can be as much as 200°C above the nominal bed temperature. If any softening takes place on the surface of either the mineral matter or the sorbent, then there is a risk of agglomeration or of fouling (Wu 2006).

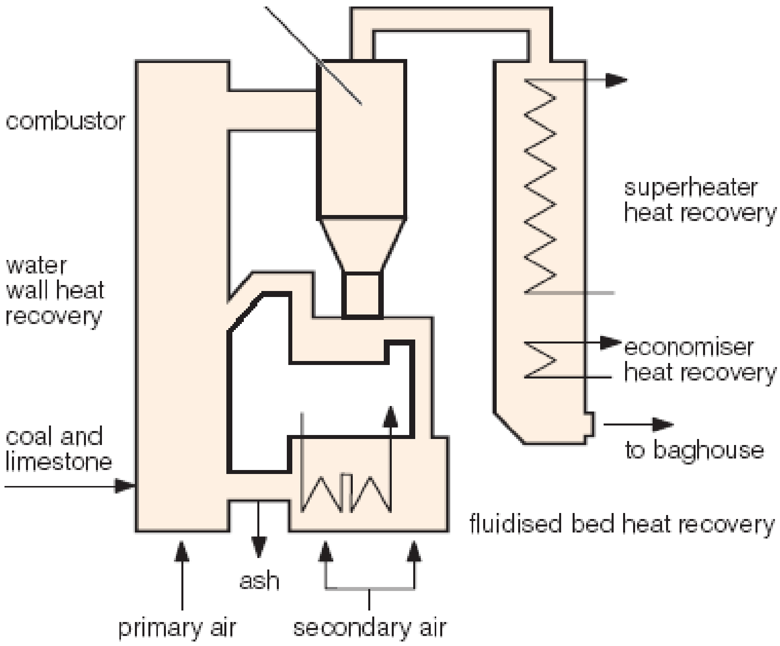

Figure 1-9: Circulating fluidised bed combustion system (Wu 2006)

A schematic diagram of a CFBC is presented in Figure 1-9. The fluidizing velocity is high enough to entrain a substantial proportion of the material, and the solids are separated from the flue gases in a cyclone operating at a temperature near that of the exhaust gas. Ash and unburned carbon are re-circulated, probably many times. Even though the solids inventory is distributed throughout the unit, a dense bed is required in the lower furnace to mix the fuel during combustion. Because of recirculation of the bed material, particle residence times are relatively long compared with the gas residence time, and can be measured in tens of seconds. For a bed burning a bituminous coal, the carbon content of the bed is only around 1%, with the rest of the bed made up of ash, together with sand (if needed), and/or lime and calcium sulphate (Wu 2006).

Overall carbon conversion efficiencies should be over 98%, leaving only a small proportion of unburned char in the residues. Larger boilers will have several cyclones in parallel to remove the solids for recirculation. One design characteristic is the need for heat recovery from the bottom ash, some of which is removed. This is part of the basic design in some units. The use of some fluidizing air prevents the plugging of ash coolers. Erosion of the heat transfer tubes in the ash coolers may be exacerbated by the air flow.

In one design, there are wall heating tubes, and then a heat exchanger with the flue gases in an external chamber. In a second design, there are platen heat exchangers in the combustion chamber in addition to the wall tubes, although further heat exchange is also needed for efficient operation. In a third arrangement, the upper part of the furnace has a considerable number of heat exchange tubes, such that the exit flue gases are substantially cooled before leaving for the cyclone (Wu 2006).

The returning ash cools the base of the combustor. Where there are heat exchange tubes in the path of the re-circulating solids the possibilities of erosion are considerably increased. In all cases, the finest fly-ash leaves the cyclone with the flue gases, and is normally separated by using an ESP. This can contain quite high proportions of carbon, possibly up to 15% (Wu 2006).

CFBCs demonstrate some significant advantages when compared to BFBCs, namely (Wu 2006):

- improved combustion and sulphur retention, due to the use of finer particles, turbulent gas-particle mixing and a high recycle rate;
- reduced bed area, due to high fludising velocities. This however is balanced by the resulting additional height and the cooler size;
- reduced fuel input points, due to small combustor size and turbulent mixing conditions;
- reduced erosion and corrosion of heat transfer tubes due to the fact that the tubes immersed in the fluidised bed cooler are subjected to significantly lower gas and particle velocities than in a BFBC; and because oxidising conditions prevail throughout the cooler whereas reducing conditions occur near the fuel feed points in a BFBC;
- increased convective heat transfer coefficients, which results to less heat transfer tubing.

Still, BFBCs perform better in some areas. Firstly, the pressure drop across a CFBC is generally greater than with a BFBC. This results in increased fan power requirements. Secondly, the large recycle rates require high efficiencies of cyclone for the recovery of the bed solids from the gas stream. In addition, the high gas velocities combined with the high particulate loadings may lead to erosion in the combustor, cyclone and associated ducting (Wu 2006).

Atmospheric CFBC is used in a number of units around 250-300 MWe size, and there are a number of commercially operating plants. There are designs for units up to 600 MWe size (Wu 2006).CFBC boilers represent the market for relatively small units, in terms of utility requirements. They are used more extensively by industrial and commercial operators in smaller sizes, both for the production of process heat, and for on-site power supply. A few are used by independent power producers, mainly in sizes in the 50 to 100 MWe range.

Figure 1-10: 460 MWe Łagisza super-critical CFB OTU Unit (FW report)

In the 100-200 MWe range, the thermal efficiency of FBC units is commonly a little lower than that for equivalent size PCC units by 3 to 4 percentage points. In CFBC, the heat losses from the cyclone/s are considerable. This loss of heat results in a reduced thermal efficiency, and even with ash heat recovery systems, there tends to be high heat losses associated with the removal of both ash and spent sorbent from the system. The use of a low grade coal with variable characteristics tends to result in lower efficiency and the addition of sorbent and subsequent removal with the ash results in heat losses. (Wu 2006). The Lagisza CFB plant in Poland started operation in 2009, operates with super-critical steam and has demonstrated net plant efficiency 43.3 % and net power output of 439 MWe with very low NO_x emissions and easy in-bed capture of sulphur (FW report). With a sub-critical cycle, the plant efficiency is of the same order as that of a PCC plant, normally between 38% and 40% on a LHV basis (Henderson, 2003; Wu, 2005).

The reported cost of investment of EUR 150 million equates to 326 €/kW installed capacity, though this Figure covers only the boiler island (JRC-SETIS 2009). Total cost in the range of 1100 – 1400 €/kW (350 – 500 €/kW, for the case of repowering of older conventional coal-fired plants) has been reported (Utilizing Clean Coal Technology—Fluidized Bed Combustion: USEA 2011).

Bubbling Fluidised Bed Combustion

Bubbling beds use a lower fluidizing velocity, so that the particles are held mainly in a bed which will have a depth of about 1 m, and has a definable surface. Sand is often used to improve bed stability, together with limestone for SO_2 absorption. As the coal particles are burned away and become smaller, they are elutriated with the gases, and subsequently removed as fly ash. In-bed tubes are used to control the bed temperature and generate steam. Overall thermal efficiency is around 30%. However, a BFBC power plant operating with higher steam conditions would achieve a higher efficiency (Wu 2006).

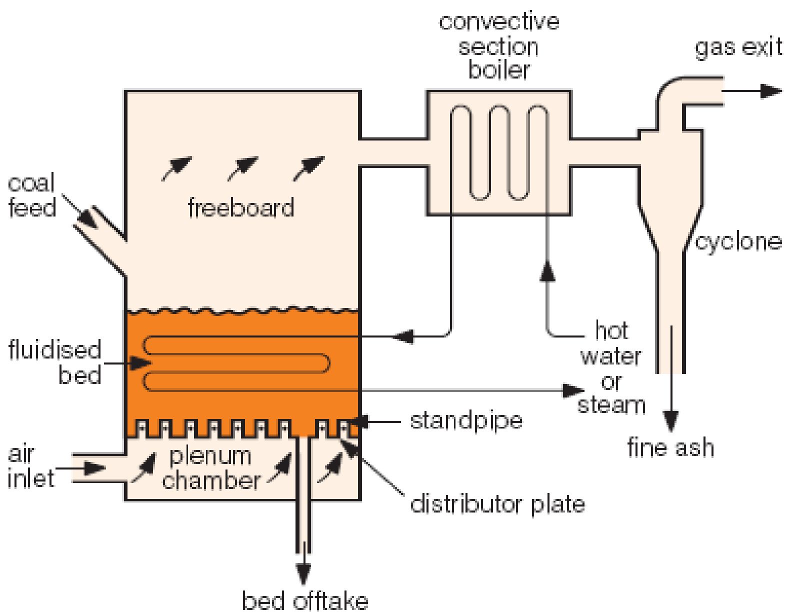

Figure 1-11: Bubbling fluidised bed combustion system (Wu 2006)

Figure 1-11 shows a diagram of a BFBC. Fuel is fed onto a packed bed of inert particles (most commonly graded sand). An upward air flow is introduced into the bed via a distributor plate (sometimes a series of closely packed tubes) so that the particles are fluidised. The distributor provides a uniform flow of air across the whole base area of the fluidised bed. It also supports the bed particles, without allowing them back into the plenum chamber, if the upward air flow is turned off and the particles become de-fluidised or slumped. With increasing gas velocity, there will be a point at which the gas-particle drag force compensates for the particle weight. At this point, inter-particle distances increase, the bed expands, and the particles appear to be suspended in the gas. This marks the onset of fluidisation. At this point, the gas velocity is referred to as the minimum or incipient fluidising velocity and depends on the size of the bed particles. When the gas velocity exceeds the minimum fluidising velocity, the excess gas passes through the bed as bubbles and the remainder of the gas leaks through the bed material. The bed is then considered to be heterogeneous or bubbling. In practice, bubbling fluidised beds are operated at gas velocities that are several times higher than the minimum fluidising velocity. Thus, the bubbles passing through the bed typically occupy 20–50% of the bed volume. The passage of the bubbles, in upwards and sideways coalescing movements, gives intensive agitation and mixing of the bed particles (Wu 2006).

Fuel is burned in the bed and at times in the freeboard above the bed. Combustion takes place at a temperature of typically 800–900°C. This temperature is stabilised by the opposing effects of the heat input from the burning fuel and outgoing heat in the flue gases and heat transferred to immersed water tubes. In the case of a boiler, such tubes form a part of the boiler construction. When BFBC is used for applications other than a boiler, such as a hot gas furnace or incinerator, there are no such water cooled surfaces. In this case, the bed temperature is controlled by passing excess air or recycled flue gas through the bed. As combustion proceeds, the fuel particles are burned away, becoming smaller and forming fine ash particles (Wu 2006).

Flue gases carrying fine particles leave the bed and pass through a section known as the freeboard (see Figure 1-11). The larger cross-sectional area than the bed, results in a reduced gas velocity in the section. Consequently, coarser solid particles entrained in the gas flow fall back to the bed by gravity. However, in a large BFBC, it is usually not practical to increase the cross-sectional area of the freeboard by an amount that would reduce gas velocity significantly. Finer particles will be carried out in the flue gas stream from the combustor. Additional air, known as secondary air and sometimes tertiary air, is often introduced into the freeboard region to complete combustion. After exiting the combustor, the flue gases pass into a convective section where heat is further recovered and the flue gases are cooled. They then further pass through a particulate control unit that can be a cyclone or a more efficient device such as a bag filter or an electrostatic precipitator. Finally, the cleaned gases are discharged into the atmosphere through a stack. Combustion leaves behind the mineral matter in the coal, most of which does not melt at the combustion temperatures (Wu 2006).

Atmospheric BFBC is mainly used for boilers up to about 25 MWe, although there are a few larger plants where it has been used to retrofit an existing unit. There are hundreds of small BFBC units in China (Wu 2006).

A disadvantage of BFBC is that in order to remove SO_2, a much higher Ca/S ratio is needed than in atmospheric CFBC. This increases costs, and in particular the cost of residues disposal. (Wu 2006)

Pressurized fluidized bed combustion

PFBC has been used on a commercial scale in Sweden and Japan with traded coals of higher quality. It is used with a combined-cycle system incorporating both steam and gas turbines. Considerable effort has been devoted to the development of PFBC during the 1990s. In PFBC, the combustor and hot gas cyclones are all enclosed in a pressure vessel. Both coal and sorbent have to be fed across the pressure boundary, and similar provision for ash removal is necessary. For hard coal applications, the coal and limestone can be crushed together, and then fed as a paste, with 25% water. As with atmospheric FBC (CFBC or BFBC), the combustion temperature between 800-900°C has the advantage that NOx formation is less than in PCC, but N2O is higher. SO2 emissions can be reduced by the injection of a sorbent, and its subsequent removal with the ash. An elevated pressure results in smaller and more frequent bubbles which, in turn, provides for smoother fluidisation. This leads to better gas and solid contact or mixing and therefore, higher combustion and sulphur retention efficiencies. (Wu 2006). Figure 1-12 illustrates the size difference between a 250 MW PFBC boiler versus a conventional PC-fired boiler:

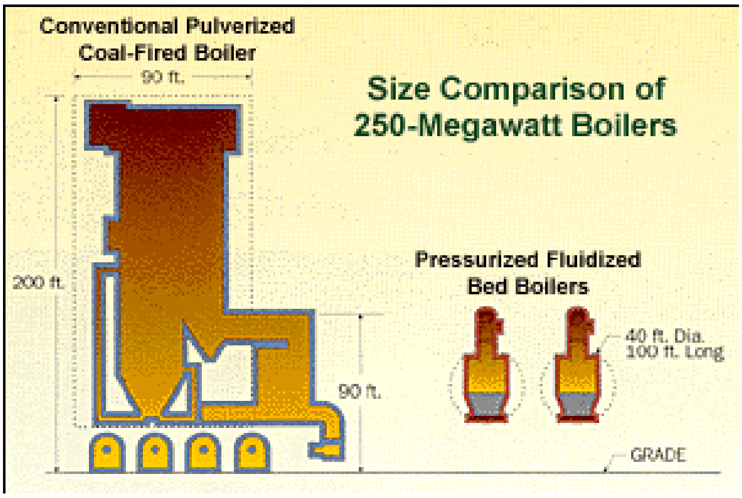

Figure 1-12: Comparison of a PFBC and a PC boiler (NPCI Guide books 2011)

PFBC units (see Figure 1-13) operate at pressures of 1-1.5 MPa with combustion temperatures of 800-900°C. The pressurized coal combustion system heats steam, in conventional heat transfer tubing, and produces a hot gas supplied to a gas turbine. Gas cleaning is a vital aspect of the system, as is the ability of the turbine to cope with some residual solids. The need to pressurize the feed coal, limestone and combustion air, and to depressurize the flue gases and the ash removal system introduces some significant operating complications. The combustion air is pressurized in the compressor section of the gas turbine. The proportion of power coming from the steam:gas turbines is approximately 80:20%.

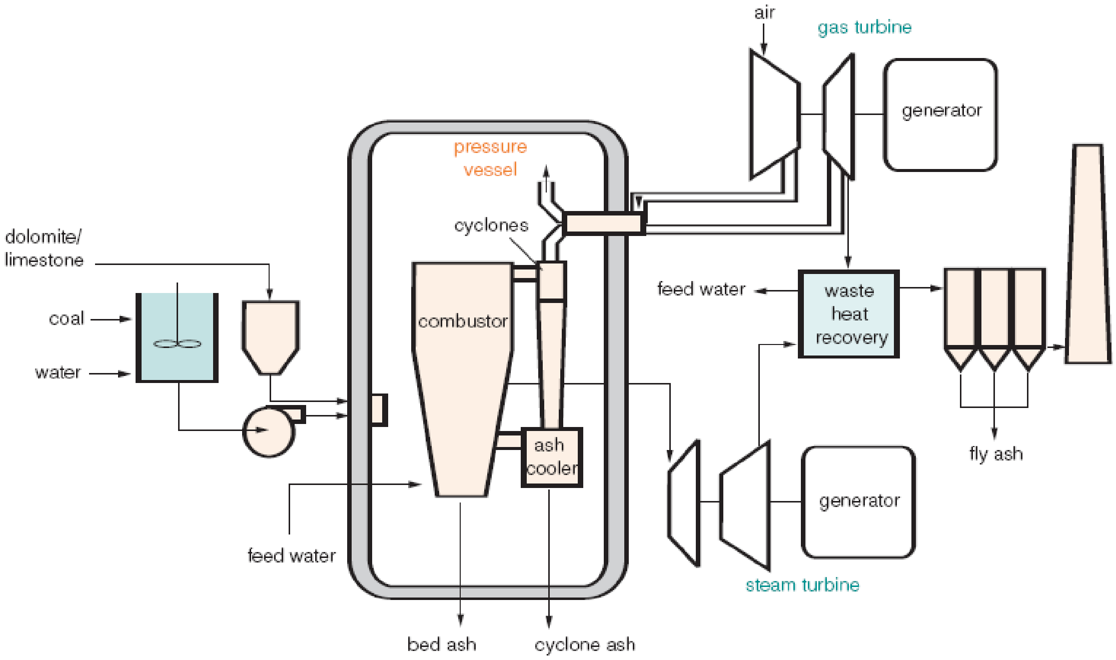

Figure 1-13: Pressurised bubbling fluidised bed combustion system (Wu 2006)

Although PBFBC (Figure 1-13) requires further technological improvements it has some potential advantages over BFBC and CFBC:

- higher combustion and sulphur retention efficiencies at elevated pressures;
- higher thermal efficiencies due to the use of higher pressures and combined cycle;
- increased fuel flexibility. PFBC plants can be designed to burn practically all types of fuel including high ash or high moisture coals;
- high degree of modularity, where appropriate, allowing for construction based on the use of two or more individual units;
- more compact/physically smaller than an atmospheric pressure unit of the same capacity. Thus PFBC is particularly suitable for retrofit applications.

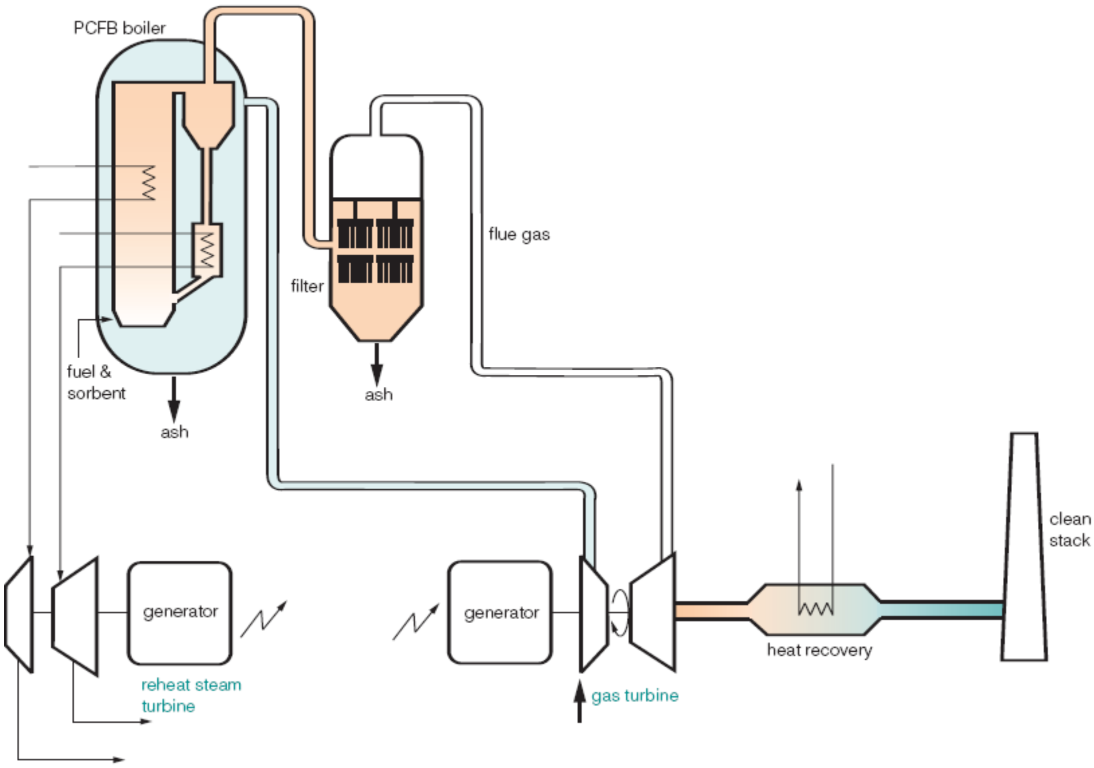

Figure 1-14: Pressurised circulating fluidised bed combustion concept (Wu 2006)

PCFBC (see Figure 1-14) has a particularly high level of heat release attainable, typically up to 40 MW/m^2 (Minchener and others, 2000). This value is considerably higher than those with competing technologies: up to 10 MW/m2 with PBFBC; 2.8–3.3 MW/m^2 with CFBC; 0.7–2.1 MW/m^2 with BFBC; and 4.4–6.3 MW/m^2 with pulverised coal combustion. Consequently, PCFBC plants could be physically much smaller than the alternative systems of a comparable capacity (Wu 2006). In addition, PCFBC technology has a number of other potential advantages including:

- increased fuel flexibility;
- higher plant efficiency than CFBC due to the use of combined cycles;
- lower capital costs compared with PBFBC and IGCC;
- lower operating costs;
- reduced emissions of NO_x, SO_2 and CO_2;
- ease of operation and maintenance;
- Suitability for repowering applications.

PFBC and generation by the combined cycle route involves unique control considerations, as the combustor and gas turbine have to be properly matched through the whole operating range. The gas turbines are rather special, in that the maximum gas temperature available from the FBC is limited by ash fusion characteristics. As no ash softening should take place and alkali metals should not be vaporised (otherwise they will re-condense later in the system), the maximum gas temperature is around 900°C. As a result a high pressure ratio gas turbine with compression intercooling is used. This is to offset the effects of the relatively low temperature at the turbine inlet. Heat release per unit bed area is much greater in pressurized systems, and bed depths of 3-4 m are required in order to accommodate the heat exchange area necessary for the control of bed temperature. At reduced load, bed material is extracted, so that part of the heat exchange surface is exposed (Wu 2006).

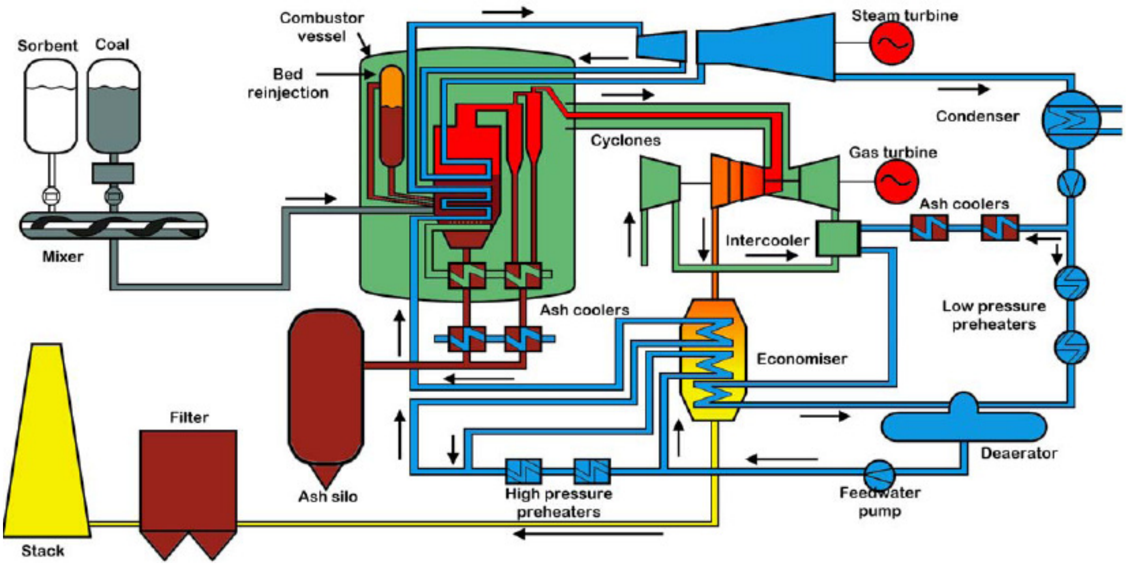

Figure 1-15: PFBC combined cycle plant configuration (Our Brochure: PFBC Environmental Energy Technology 2011)

The current PFBC demonstration units are all of about 80 MWe capacities, but two larger units have started up in Japan at Karita and Osaki. These are of 360 and 250 MWe capacity respectively, and the Karita unit uses super-critical steam. This plant has a net thermal efficiency of about 42% on an HHV basis (44% on an LHV basis), representing the state of the art for PBFBC technology. The Third Generation PFBC - Pressurized Deep Bubbling Bed in Combined Cycle units (see Figure 1-15) are intended to give an efficiency value of over 40% (40.9% to 42.3%) (Our Brochure: PFBC Environmental Energy Technology 2011), and low emissions, and developments of the system using more advanced cycles are intended to achieve efficiencies of over 45% (Wu 2006).

In terms of total cost of these kind of facilities the PFBC demonstration projects have yielded a cost in the range of 1300 – 2200 €/kW and for fully commercial project the cost is expected to drop to the range of 700 – 1100 €/kW (2.4 Utilizing Clean Coal Technology—Fluidized Bed Combustion: USEA 2011).

1.2 WIND POWER GENERATION

1.2.1 Installed capacity

The global installed wind capacity has grown at 29% annual average between 2000 and 2009 and added 35.7 GW in 2010. The cumulative capacity achieved 194.4 GW at the end of 2010. China leads the list of highest installed capacity, followed by the USA, Germany, Spain and India. As in recent years, strong growth is expected in China and the USA in the future.

In the EU27 9.3 GW of new wind capacity was installed during 2010, bringing the cumulative capacity to 84 GW (EWEA 2010). Wind power generation in 2010 is estimated to be around 160 TWh covering 4.9% of the EU27 gross electricity generation (GEG). Estimations for 2020 predict wind power generation to be 600 TWh, covering 14-16 % of the EU-27 GEG. In 2030 wind power generation should achieve 644 TWh, covering 15.4% of the EU27 GEG (EC, Eu Energy Trends to 2030 2010). The industry targets are more optimistic and forecast a wind power share of 12-15% in 2020 and above 20% in 2030 in the EU27.

EU Countries with a high share of wind power in the electricity mix include Denmark with 21.8%, Spain with 16 %, Portugal with 14.8% and Ireland achieving 12.5%. In 2020 Denmark is expected to achieve a wind power share in the electricity mix around 30%, while Portugal, Spain, Ireland and Germany would be in the 15-20% range. Growth will carry on in all the indicated countries with Denmark achieving a wind power share around 36% in 2030, and Spain, Portugal, Ireland and Germany being around 25%.

The contribution of the offshore market is low. At the end of 2010 the installed offshore capacity was slightly above 3 GW. This is less than 2% of the total installed capacity from wind power. In 2020 this share could be around 17% and in 2030 around 40%. This would imply more TWhs from offshore resources than from onshore due to the significantly higher electricity production from offshore farms.

1.2.2 Resources

Wind speed is the most important factor affecting wind turbine (WT) performance. Wind speed increases with height creating the wind shear profile. Surface obstacles such as forest and buildings, decrease the wind speed. Generally, utility-scale power plants require minimum average speeds of 6 m/s. WTs start to capture energy at cut-in speeds of around 3 m/s and the energy extracted increases roughly proportionally to reach the turbine rated power at around 12 m/s, remaining constant until strong winds put at risk its mechanical stability and the turbine is forced to stop at cut-out speeds around 25 m/s.

Typical capacity factors of wind energy in Europe are 1800-2100 equivalent full-load hours onshore and 3200-4000 offshore. Technology progress tends to increase these figures but best sites onshore tend to have already been taken.

According to the German Aerospace Center [DLR, 2006] the economic potential of wind power in the EU27 is 1336 TWh/y, which is equivalent to 40% of the current GEG. The county with highest potential is the UK with 344 TWh/y followed by Germany with 262 TWh/y. There are massive wind energy resources in the North Sea which still can't be accounted as potential as several technical issues have to be overcome to enable their exploitation. With the advance of technology, for instance by enabling offshore exploitation further from the shore and in deeper waters, the wind energy potential will increase and even multiply – but all this will come at a cost.

All these numbers indicate a very relevant fact: wind energy has a huge potential to mitigate climate change. It will remain a very relevant component in fulfilling carbon emission targets in Europe and on the global level. One of the barriers the technology is facing is the social acceptance, often based on the visual impact of wind generators mixed up with the NIMBY syndrome.

1.2.3 Technology

Throughout the last decades the three-bladed, horizontal-axis rotor arose as the most cost-effective and efficient WT design. The trend towards ever larger WTs has stabilized during the last years. Currently land-based turbines are mostly rated either at the 0.75-0.85 MW, the 1.5-2 MW or the 3 MW range. A 0.8 MW turbine is around 80 m high and has a rotor diameter around 50 m. For a 2 MW unit the height is around 105 m and the rotor diameter is around 80 m. Some technological barriers that prevent the scaling-up of turbines include the high mechanical loads and the limitations to transport and install large components. Technological variations of WT design include tower structure and material, nacelle orientation, rotor speed, tip speed, blade regulation, power electronics, etc. WTs are evolving from conventional variable speed drive through to the doubly-fed induction generator, currently the most applied, into the permanent magnet generator with full power converter. Pitch control has become the technology of choice, coupled mostly with variable speed regulation.

The main WT technology driving goals are to minimize capital costs, maximize reliability, enable application in new geographic sites (e.g. forests and cold areas), adapt to stricter grid requirements, overcome potential bottlenecks, etc. This translates into a wide variety of research activities and demonstration, including improvements in aerodynamic performance, acoustic performance, material alternatives, manufacturing technology and scale, power electronics, etc. For instance blades are tending towards joined elements for larger designs, improved load and fatigue testing, winglets to improve tip losses manufacturing speed-up and the use of hybrid composites.

Although there is still room for improvements, onshore wind power is a mature technology. On the other hand, offshore wind power is much behind in this sense, and has still many pending issues before having the potential to capture a significant market share.

Offshore WTs have a saline and tough working environment. Due to the more difficult access, they require higher reliability by lower maintenance than onshore installations. Furthermore, grid extension is more costly and technologically challenging. Currently there is a very tight supply chain of high voltage alternating current and direct current subsea cables, where there are still few manufacturers.

Current support structure options for offshore wind turbines are the most common monopole and the less common gravity-based foundation. Diversification can be expected in the future with tripods, jackets and even gravity-based foundations being applied beyond the traditional limits of the technology. Floating foundations are being explored with good initial results, and could capture the very large wind energy resources available in deep waters. Both industry and academia see 10 to 20 MW turbines as the future offshore machines.

1.2.4 Economy

Onshore WT prices are following a downward trend based on a learning factor of 8-10%. Prices detached from this trend between 2004 and 2008 due to supply-chain limitations. The sector experienced an increase in raw materials and component prices. Onshore WT prices climbed from 1020 €/kW in 2004 to 1410 €/kW in 2008. In 2009 prices decreased to 1150 €/kW. For the future the technology is expected to retake its downward price trend. Offshore investment costs have been even more affected in the mentioned price upward trend. Prices climbed from 2200 €/kW in 2007 to 2490 €/kW in 2008 and even higher to 3560 €/kW in 2009. O&M costs are around 12-17 €/MWh for onshore and 15-33 €/MWh for offshore installations.

In the long run, the rising cost of fossil fuels as well as the related emission costs on one hand, and the decreasing cost of wind power on the other, will make average wind electricity competitive with fossil fuel generation. This is likely to be the case already in 2020 for onshore wind power.

The wind market is affected by barriers of integration in the technology mix with the increasing penetration level. The integration of wind energy in the electricity grid can occasionally involve other costs including the reinforcement of grids and the need for additional balancing power and ancillary services. These costs can be reduced through creating larger balancing areas, reducing the wholesale market gate-closure time, more frequent intraday markets and better forecast systems. There is also room for low-cost improvement by optimising the grid operational procedures.

1.2.5 Increasing wind energy share in the electricity mix

Integrating wind power in the electricity mix becomes more challenging with an increasing penetration level. Enabling higher wind energy shares can be achieved by integrating flexible power generation in the technology mix, such as hydropower plants and gas turbines, and introducing demand control measures. These two points can be resumed as generation- and demand-side flexibility. Other effective measures are to create a larger balancing area through international interconnections and to use electricity storage in reservoir- and pumped-hydropower schemes. Research on wind energy integration includes improving wind speed forecast and elaborate adapted wholesale market and balancing operations. Taking into account the wide variety of solutions, the integration of roughly 50% wind power into an electricity system is seen as technically possible.

1.3 HYDRO-POWER GENERATION

The global installed hydropower capacity achieved 723 GWe in 2010 generating around 3190 TWh/y, which is equivalent to 16% of the global electricity generation. With an installed capacity of 102 GWe, hydropower generation in the EU27 was 323 TWh in 2010. This accounts to 9.8% of gross electricity generation and around 60% of electricity generation from renewable energy sources. The economic potential is estimated to be around 470 TWh/y. Hydropower generation in the EU27 is expected to increase modestly in the future, up to 341 TWh/y in 2020 and up to 358 TWh/y in 2020. Nevertheless, in terms of share in the gross electricity generation, and due to the increasing electricity demand, a decrease to 9.2% in 2020 and further down to 8.8% in 2030 is expected. The facts behind this ongoing slow evolution is that more than 50% of favourable sites have already been exploited across the EU27, while due to environmental restrictions it's unlikely that Europe could see much more expansion.

Nevertheless, the European hydropower industry will remain active, on one hand, because growth outside Europe remains strong, with a huge market potential in China and India, and on the other hand, due to the need for rehabilitation and refurbishment of existing hydropower facilities in Europe. The refurbishment market segment is of interest for Europe with overall an ageing hydropower park, but also to ensure that no energy capacity losses are incurred with the implementation of higher environmental standards.

There are two hydropower plant configurations: dams and run-of-river schemes. The first is with reservoir, the other without. Run-of-river plants operate in a continuous mode, contributing to base-load electricity. The dam schemes can be subdivided into small and large, with 10 MW being the separation line. As run-of-river plants are small, a different classification of hydropower is also found, where the technology is divided in large and small plants, and small plants are subdivided in dam and run-of-river schemes. It must be noted that run-of-river hydropower is an emerging technology with a very low market share. Therefore, the following text focuses on dams.

Reservoir-based hydropower is a flexible electricity generation technology enabling quick response to electricity demand fluctuations. Small dams serve for short term storage, while large dams can provide seasonal storage. Hydropower can be implemented in combination with other activities, such as flood regulations and wetland management.

Large hydropower plants can imply a serious environmental impact. The dam can affect water availability downstream, cause habitat fragmentation and damage flood ecosystems. Furthermore, it can prevent silt from reaching the downstream basin. On the other hand, land areas are flooded upstream. This could destroy valuable ecosystems. There are reports of hydropower plants emitting methane from decaying organic materials, although this is rare and can be avoided by proper reservoir design. Also a social impact would result, should the new reservoir require the displacement of population. Small-scale hydropower is normally designed to run in-river. This is an environmentally friendly option, because it does not interfere significantly with river flows. Current R&D efforts in hydropower include innovative technologies to minimize its environmental impact.

There are over 21000 small hydropower plants in the EU27, but they cover only 13% of the generated hydropower. The largest remaining EU potential lies in low head plants (<15m), and in the refurbishment of existing facilities. Of particular interest are very-low-head plants (<5m), a promising distributed generation technology. Its European potential is about 1 to 1.5 GW. These systems are now in the demonstration stage and their typical power rating is of the order of a few hundred kWs to 1 MW.

In 2008, capital investment costs for building large hydropower facilities (>250 MW) were of the order of 1000 to 3600 €/MW. In 2008, average capital costs for small hydropower plants were of the order of 2000 to 7000 €/kW.

As part of R&D in hydropower technology different materials are being investigated, including steel alloys that are more resistant to turbine cavitations, and fiberglass, special plastics and aluminum to replace steel in some applications. Efforts are being addressed to improve control systems and power electronics and to optimize generation as part of integrated water-management systems. For both sectors, research includes the reduction of O&M costs through maintenance-free and remote operation technologies. One further priority is the development of cheaper technologies for small-capacity and low-head applications, to enable the exploitation of smaller rivers and shallower reservoirs. Finally, even when the highest efficiency of small turbines has increased from around 88 to 93% in two decades, research can help further improve this figure.

1.4 GEOTHERMAL ENERGY

Geothermal resources can be classified in low-, medium- and high-enthalpy fields. Low-enthalpy fields imply low temperature resources (<100°C), which are exploited directly for heat applications such as space and water heating. For a temperature close to 100°C also power generation is feasible, e.g. with an ORC, although with efficiencies below 5%. Medium- and high-enthalpy resources imply the temperature range of 100-180°C, and above. These resources are exploited for power generation with and without heat cogeneration.

In 2009 the installed geothermal power capacity achieved 9 GW_e generating around 60 TWh of electricity. This is less than 1% of the global electricity demand. Geothermal power potential is currently limited to tectonically active regions. Countries with high potential include Iceland, Indonesia, Philippines, New Zeeland and Japan among others. In general, high-enthalpy geothermal fields are only available in areas with volcanic activity. The challenge is currently to develop Enhanced Geothermal Systems (EGS) to exploit deep resources. This would increment the geothermal power potential and extend it to new geographic areas.

As geothermal resources imply a wide range of enthalpy and site-variable conditions, different technologies are applied for the heat to power conversion. The less common are dry steam plants. In this case the naturally produced steam is dry enough to go through the turbine. Nevertheless, fields with pure natural steam are rather rare. Most geothermal power resources are based on a mixture of steam and hot water and require a single- or double-flash system to separate out the hot water, before the steam is routed to the turbine. Flash plants are the most common geothermal power plants. Finally, binary plants are applied together with low and medium-enthalpy geothermal fields. The system integrates two loops. The first is a water loop that extracts the ground-heat and releases it in a heat exchanger to the second loop, where the process fluid evaporates and subsequently flows through the turbine. The process fluid could be an ammonia-water mixture used in a Kalina cycle or a mixture of hydrocarbons used in an ORC. The boiling and condensing points of the process fluid are adapted to the geothermal resource temperature.

Current investment costs of geothermal power plants are typically around 2800 €/kW_e. O&M costs are around 3.5% of the investment cost. Power generation costs are roughly 65 €/MWh.

1.5 OCEAN ENERGY

Ocean energy is a term used to describe renewable energy derived from the sea, including ocean wave energy, tidal and open-ocean current energy (sometimes called marine hydrokinetic energy), tidal barrages, offshore wind energy, and ocean thermal and salinity gradient energy. They are used largely for the generation of electricity although some secondary uses exist, including desalination and compressed air for aquaculture.

Globally, the theoretical potential of OE has been estimated by the International Energy Agency's Implementing Agreement on Ocean Energy (IEA-OES) between 20 000 and 90 000 TWh/year (as a reference, the world's electricity consumption is around 16 000 TWh/year). This breaks up depending on technology, in the following way: tide and marine current resources represent estimated annual global potentials exceeding 300 TWh and 800 TWh per annum, respectively. Wave energy has an estimated theoretical potential of between 8 000 TWh and 80 000 TWh per annum. The theoretical potential of ocean thermal gradient (also known as OTEC) is estimated around 10 000 TWh per annum. The potential of salinity gradients is estimated at 2 000 TWh per annum.

The main form of ocean energy is energy from waves, tides, marine currents, salinity gradients and temperature gradients.

1.5.1 Ocean Wave Energy Conversion technologies

Ocean wave energy is mainly derived by the influence of the wind on the ocean surface. The result ripples become chop and finally swells. Wave energy, due to the difference of properties in the energy carrier media, is less intermittent and more predictable than other renewable resources. The economically exploitable resource varies from 140-750 TWh/y for current designs of devices and could rise as high as 2 000 TWh/y if the potential improvements to existing devices are realized.

Various hydraulic or pneumatic power conversion systems are used, and in some cases, the mechanical motion induced by the wave energy is converted directly to electrical power (direct-drive). These devices can be bottom-mounted or floating and vary in size, orientation, and distance from shore. The main wave devices can be categorized as follows:

- Point Absorber

It is a floating or bottom up structure that absorbs energy in all directions through movements near the water surface. The power take off systems varies according to the configuration of the reactor. Anchored to the ocean floor and submerged fully in deep water away from surf breaks, some point absorbers consist of an array of submerged buoys tethered to seabed pump units. The buoys move along with passing waves, driving the pumps, which in turn pressurize water that is delivered ashore via a pipeline (Bloomberg 2011).

- Overtopping Terminator

A terminator reflects or absorbs all of the wave energy—hence it "terminates" the waves. Its operation relies on the physical capture of water from waves. One type of terminator is an overtopping device that uses a floating reservoir structure, typically with reflecting arms to focus the wave energy. As waves arrive, they overtop the ramp and are restrained in the reservoir. The potential energy due to the height of collected water above the sea surface turns conventional low head hydro turbines. These turbines are coupled to generators to produce electricity.

- Linear Absorber or Attenuator

A linear absorber, sometimes called an attenuator, is a device that is large compared to a typical wave's length. The system is parallel to the direction of wave propagation and is composed by multiple sections that rotate in pitch and yaw relative to each other. That motion is used to pressurize a hydraulic fluid, which then turns a turbine that is coupled to a generator to produce electricity. It has a lower area in parallel to the waves than the terminator, so the system experiences lower forces. Such devices may consist of cylindrical sections linked by hinged joints which flex and bend with the movement of the waves.

- Oscillating Water Column

An oscillating water column (OWC) terminator is a conversion device of hollow structure. It harnesses the motion of the ocean waves as they push an air pocket up or pull it down. This device is a partially submerged chamber with air trapped above a column of water. The movement of the column due to the wave entering and exiting is acting as a piston on the air, compressing and decompressing. Thus reversing stream of high-velocity air is generated. This air is channelled through a turbine/generator to produce electricity. An OWC is also a type of wave terminator.

- Oscillating wave surge converter

It extracts energy caused by wave surges and the movement of water particles within it. Some technologies of this kind are anchored to the seabed at around 10 meters depth and capture its energy through a mechanical hinged flap triggered by the motion of the waves.

- Submerged pressure differential

Typically located near shore and attached to the seabed, use the movement of the sea level, due to the motion of waves. This movement on the device induces a pressure differential, which then pumps fluid through the system in order to generate electricity.

1.5.2 Tidal and Open-Ocean Current Energy Conversion Technologies

Tidal energy is the potential energy between the high and low tides and is cost-effective when the "usable head" is five meters or more. The large mass of moving water in tidal and other marine currents contain kinetic energy that can mostly be captured by means of wind-turbine-like technology. A tidal current (or hydrokinetic) turbine converts the kinetic energy in a moving mass of water to electricity. The gravitational forces of the sun and the moon on Earth's ocean cause sea level changes, which, in turn, give rise to strong tidal currents. Open-ocean currents are the vertical or horizontal movement of both surface and deep water throughout the world ocean caused by Coriolis forces and thermal gradients. To convert tidal or open-ocean currents to electricity, energy conversion devices are placed in the flowing water stream where they harness the kinetic power of the moving water. Capacity factors expected for tidal barrages varies from 1 800 to 3 000 full-load hours. The global tidal range energy potential is estimated to be about 200 TWh/y, about 1 TW being available at comparable shallow waters.

- Horizontal axis turbine

It exacts energy from the moving water similar to the way wind turbines capture energy from moving air. The axis of rotation is parallel to the water stream and thereby horizontal with respect to the seabed.

- Vertical axis turbine

It operates similar to horizontal axis turbines but here the turbine is at an angle 90 degrees.

- Non-turbines

In this category oscillatory hydrofoils, vortex-induced motion, and hydro Venturi devices are grouped. Hydrofoils are mounted on oscillating arms. The arms are lifted due to the tidal currents and the kinetic energy can be harnessed. In venture devices a duct to concentrate the flow of water past a turbine is used.

1.5.3 Ocean Thermal Energy Conversion Technologies (OTEC)

There are potentially three basic types of OTEC power plants: closed-cycle, open-cycle, and various blends of the two. All three types can be built on land, on offshore platforms fixed to the seafloor, on floating platforms anchored to the seafloor, or on ships that move from place to place.

OTEC is the extraction of solar energy via a heat engine operating across the temperature difference between warm surface ocean water and cold deep ocean water. Temperature differential between water surface and ocean depths, around 20^{o}C, can drive a Rankine thermodynamic cycle to generate electricity. Ammonia is one OTEC fluid used because of its thermal properties. Cycle efficiency may be boosted by superheating, reheating, and similar strategies used in steam cycles, though the cost of the added complexity must be offset by any performance gains.

An open-cycle OTEC system uses warm surface ocean water as the working fluid. The warm ocean water is introduced into a vacuum chamber whereby a portion of the water flash evaporates. The low-temperature, low-pressure steam (relative to most existing power plants) expands through the turbine to drive the generator. The expanded vapour is converted back to a liquid in the condenser using cold deep ocean water. The condensed liquid is available as desalinated water. The solar collector is such a device is the ocean itself.

1.5.4 Salinity Gradient or Osmotic Conversion Technologies

In these technologies the energy retrieved from the difference in the salt concentration between seawater and river water. Two practical methods for this are reverse electro dialysis (RED) and pressure-retarded osmosis (PRO).

Both processes rely on osmosis with ion-specific membranes. With RED, a salt solution and freshwater pass through a stack of alternating cathode and anode exchange membranes. The chemical potential difference between saltwater and freshwater generates a voltage over each membrane, and the total potential of the system is the sum of the potential differences over all membranes.

It is important to remember that the process works through differences in ion concentration instead of an electric field, which has implications for the type of membrane needed. In RED, as in a fuel cell, the cells are stacked.

With PRO, seawater is pumped into a chamber that is separated from a freshwater solution by a semi-permeable membrane. As a result of the osmotic pressure difference between the two solutions, water diffuses through the membrane into the seawater chamber, thereby diluting the seawater and increasing its volume. Pressure compensation in the chamber spins a turbine to generate electricity. Salinity power is one of the largest sources of renewable energy that is still not exploited. The potential energy is large, corresponding to 2.6 MW m^3/sec flow of freshwater when mixed with seawater. The exploitable potential world-wide is estimated to be 2000 TWh/y.

1.6 SOLAR PHOTOVOLTAIC ELECTRICITY GENERATION

1.6.1 Technology overview

PV technologies are classified as first, second and third generation. First generation PV is the basic crystalline silicon (c-Si) technology. Second generation PV implies the Thin Film (TF) technologies. Third generation PV, often also mentioned as emerging technologies, includes Concentrator PV (CPV) and organic solar cells. These imply both fully organic PV cells (OPV) and the hybrid dye-sensitized solar cells (DSSC). In addition to that, a number of novel technologies are under development, such as nanotechnology-based approaches to develop high performance cells.

Crystalline silicon modules dominate the PV market and are expected to continue doing so at least along the next decades. The efficiency of mono-crystalline modules is in the range of 13-19% and that of multi-crystalline modules is in the range of 11-15%.

Four types of Thin Film modules are commercially available: Amorphous silicon (a-Si), multi-junction thin silicon film (a-Si/µc-Si), cadmium telluride (CdTe) and Copper indium diselenide (CIS). The record efficiency of commercial TF PV modules and lab cells is resumed in Table 2-1.

Table 1-1: Summary of record efficiencies of thin film Technologies [EPIA, 2011]

Thin film technology	Record commercial module	Record lab cell
a-Si	7.1%	10.4%
a-Si/µc-Si	10%	13.2%
CdTe	11.2%	16.5%
CIGS/CIS	12.1%	20.3%

Efficiencies of organic solar cells are still very modest. OPV achieves efficiencies around 6% for very small areas and below 4% for larger areas. DSSCs perform much better in the lab achieving double digit efficiencies on small areas, but commercial applications have still modest efficiencies below 4%. Another major challenge of this technology is the long term stability of such organic cells. The technology has the potential for very low module costs (<0.5 €/Wp).

High Concentration PV (HCPV) has also a very promising cost reduction potential. These systems concentrate the direct solar beam and therefore are very suitable for regions with high direct irradiation values. The concentration factor is usually above 400x. HCPV cells are based on III-V compounds (generally gallium arsenide). The current III-V cell has an efficiency of 42.4%. Efficiencies above 50% can be expected on the longer run. The most applied system layout is a Fresnel lens focusing directly on a 1 cm^2 cell. The concentration factor range between 400x and 700x is the most common, but also extreme concentration systems, i.e. above 1000x, are available. The system efficiency is typically in the range of 20-25%.

1.6.2 Manufacturing process

The manufacturing chain of crystalline silicon modules starts with the production of solar grade silicon (6N-8N) from metallurgical silicon. The Siemens process is the dominating technology in this manufacturing step. The resulting solar silicon is then crystallized. On the industrial level two crystal growth techniques dominate: the Czochralski pulling technique to produce mono-crystalline silicon and the block casting technology to produce multi-crystalline silicon. The produced ingots are then sliced into wafers, which are used to produce PV cells. This step includes surface treatment, the formation of the p-n junction through doping in a diffusion oven, deposition of an anti-reflective coating on the front surface and eventually the addition of metal contacts. The cells are then sandwiched between layers of coating material to protect them from the environment. Transparent glass is used for the front, while a weatherproof backing, typically a thin polymer, is applied to the back of the module. The cover is attached using thin sheets of EVA or PVB. Frames can be placed around the modules to increase their strength. For some specific applications, such as Building Integrated PV (BIPV), the back of the module is also made of glass to allow light through [EPIA, 2011].

Advances and alternatives in c-Si cell manufacturing methods are producing cells with higher efficiencies. Some of the most promising technologies include the buried contacts cell, the back contact cell, the Pluto cell and the HIT cell (Heterojunction with Intrinsic Thin Layer). The Back Contact cell has the highest efficiency with 22%. In this cell, the front contact of the cell is moved to the back. The cell's surface area is increased and shadowing losses are reduced. This technology currently provides with 22% the highest commercial cell efficiency available on the market [EPIA, 2011].

Thin film modules are constructed by depositing extremely thin layers of photosensitive material on to a low-cost backing such as glass, stainless steel or plastic. The deposited layers include a Transparent Conducting Oxide (TCO), which acts as the front contact of the PV cell, the semiconductor material layer/s and the back contact. A variety of deposition technologies are used in TF PV. Within the manufacturing process the deposited films are laser-cut into multiple cells. Thin film modules are normally enclosed between two layers of glass encapsulated with a polymer and are frameless. If the photosensitive material has been deposited on a thin plastic film, the module is flexible. For flexible substrates, the manufacturing process uses the roll-to-roll (R2R) technique. Using R2R has the potential to reduce production time and costs, and both manufacturing and transport costs [EPIA, 2011].

1.6.3 Installed capacity

The global annual installed PV capacity in 2010 was 16.6 GWp. Estimations of the European Photovoltaic Industry Association (EPIA) for 2011 locate this value by 21 GW. The annual installed capacity in 2015 should be even above 40 GW. Of the 16.6 GW installed last year as much as 13.2 GWp were installed in the EU with 7.4 GW being in Germany, 2.3 GW in Italy, 1.5 GW in the Czech Republic and 2 GW in the other member states. The annual installed PV capacity in the EU along the last decade has grown by an average of 40%. The important markets outside the EU remain Japan and the USA.

1.6.4 Market share

Currently the PV market is still dominated by c-Si modules. In 2010 the market share of c-Si was 80%, with the other 20% being TF PV. CPV, OPV and DSSC are just beginning to enter the market. According to the European Photovoltaic Industry Association (EPIA) 161 companies are active in Thin-film PV in 2010, of which 131 produced silicon-based thin-films. Around 30 produced CIS Thin-films, while only 4 where active in CdTe. Despite that, it is CdTe precisely that have the highest market share among Thin-film technologies. Today, there are more than 20 companies offering or developing HCPV systems, although the market share of the technology is negligible. Suppliers of OPV have still modest production. They are moving towards full commercialization and have announced plans to increase production of more than 1 GW by 2012. Manufacturers of DSSC are expected to produce 200 MW in the same year.

EPIA expects that by 2020 Silicon wafer-based technologies will account for about 61% of sales, while Thin-films will account for 33%. The remaining 6% will be basically CPV, OPV and DSSC. In 2030 the market is expected to be more or less equally divided between first, second and third generation technologies.

1.6.5 Grid-parity

PV still relies on support schemes. While PV modules become cheaper following a learning curve with a learning factor of 22%, the cost of electricity generated from fossil fuels becomes higher. The tendency is that this will lead eventually to grid-parity. Basically, three factors influence this scenario: The PV system cost, the solar conditions of the installation site, and local electricity prices. Large systems in Germany have achieved in 2010 prices around 2700 €/kWp. Prices of large systems could evolve to around 1300 €/kWp and around 1000 €/kWp in 2030. Large PV power plants in Germany would achieve a levelized cost of electricity around 15 cent/kWh in 2020 and around 10 cent/kWh in 2030. In southern Spain such costs would be around 10 cent/kWh in 2020 and 7 cent/kWh in 2030. Cost reductions will carry on beyond 2030. On the longer run, PV is expected to achieve a levelized cost of electricity around 5 cent/kWh in southern Europe, resulting thereby cheaper than all fossil fuel technologies. Such cost reductions in PV will be achieved through: technological innovation, production optimization, economies of scale, increased performance ratio of PV systems, extended lifetime of PV systems and developments of standards and specifications [EPIA, 2011].

Smaller rooftop PV installations are more expensive than large solar farms. Prices of an installation of few kWs are typically around 3500 €/kWp. Nevertheless, these are consumer-near distributed generation facilities and compete with the retail electricity prices. Despite their higher cost, such installations will achieve grid-parity before centralized solar farms. Therefore, in the medium term, PV systems will be introduced as integral parts of new and retrofitted buildings.

1.6.6 Energy Pay-back Time

The energy pay-back time (EPBT) of a PV system depends on the applied technology and the location. Installations in Southern Europe using crystalline silicon modules have an energy payback time of 1 to 2 years. Installations using CdTe modules is southern Europe have an energy payback time around 1 year. HCPV have the potential for very low energy payback times, roughly around 6 months in southern Europe. The PV industry with its different segments continues to reduce the energy payback time of its modules and systems, as this often goes hand in hand with cost reductions. For instance, the reduction of semiconductor usage (g/Wp) is one important cost reduction factor in crystalline silicon and thin-film PV which leads also to reduced EPBT.

1.6.7 Recycling

The annual installed PV capacity started to be significant in the early 1990s with the first support schemes for grid-connected PV launched. Therefore, full-scale end of life recycling is still ten years away. As a matter of fact, many recycling facilities today process mainly defective modules and manufacturing scrap.

In 2007, leading manufacturers embraced the concept of producer responsibility and established a voluntary, industry-wide take-back and recycling program. PV CYCLE embraces more than 100 companies representing over 85% of the total European PV market. All members are to implement a collection and recycling system developed by PV CYCLE, which will be operational soon.

1.6.8 Bottlenecks

The PV industry has more the 60 potential bottlenecks such as Iso-graphite, solar glass, Tedlar, Diamond coated saw wires, silver pastes for cell contacts etc., but few are considered severe. For many years poly-silicon has acted as a severe bottleneck as the production knowhow has been limited to few companies, but this bottleneck seems to be overcome with many newcomers in the business and substantially increased manufacturing capacity. Poly-silicon prices in recent years have become stable and reflect manufacturing costs. Potentially severe bottlenecks are rare metals like Tellurium, Indium and Gallium, all of which are used in thin-film PV. Germanium is also a potential bottleneck, which is used in HCPV cells. Tellurium is a by-product of copper processing. Availability of Te in the long term may depend on whether the copper industry can optimize extraction, refining and recycling yields. Indium is available in limited quantities, but there are no signs of an incoming shortage. While there is a lot of Indium in tin and tungsten ores, extracting it could drive the prices higher. A number of industries compete for the indium resources: the liquid crystal display (LCD) industry currently accounts for 85% of demand.

1.7 BIOENERGY – POWER

Biomass energy accounts for around 14% of total primary energy consumption. Even though estimates of the amount of energy that can be supplied from biomass varies widely, it is estimated that by 2050 it could provide as much as 50% of global primary energy supply. Generating electricity from biomass uses exactly the same technology that has become common in the power generation industry - furnaces to burn coal, boilers to raise steam from the heat produced and steam turbines to turn the steam into electricity.

1.7.1 Direct Combustion

On a global scale, biomass supplies more than 1% of the electricity demand, i.e. some 257 TWh per year (World Energy Outlook 2009. IEA, Paris, 2009). The use of combustible renewables (especially solid biomass) has a significant impact on the energy balance of countries and regions with abundant primary resources such as the European Nordic countries, Austria, and Switzerland while the use of biogas is increasing in Germany, the Netherlands, the United Kingdom, and Italy, while power generation based on biomass and waste as well as co-firing in coal-fired power plants, are also rapidly growing (World Energy Outlook 2009. IEA, Paris, 2009). The investment costs of biomass power plants with capacities of up to 50 MWe are between €2100 and €4200/kWe. The incremental investment cost and the annual O&M cost of biomass co-firing in coal-fired power plants are approximately €240/kWe and about €9/kWe, respectively. Biomass-based power and biomass co-firing would have a target generation cost of 35 – 50 €/MWh, which is equivalent to 55 – 70 €/MWh (IEA-ETSAP, Biomass for Heat & Power 2010).

Biomass-fired power plants can be characterised by the boiler technology. Water-cooled vibrating grate (VG) boilers are an established technology for power generation from wood residues. Based on natural circulation, these boilers are designed to burn low-heating-value (LHV of about13.8 MJ/kg) wood residues, with 30% humidity. The typical power plant capacity is in the order of 10 MWe.

Bubbling fluidised bed combustion (BFBC) boilers for solid biomass and other feedstock are a proven and commercial option. In the BFBC boilers, the ascending air speed is sufficiently high to maintain the bed in a state of fluidisation, with a high degree of mixing, but it is low enough to make most of the solid particles lifted out of the bed fall back. The result is a dense bed with uniform temperature and burning char, and rather small over-temperatures. The dense part of the fluidised bed has a void fraction that is near to minimum fluidisation requirement. Within the dense part of the bed, a bubble phase exists, with a low content of solids. The bubbles formed from air in excess rise through the dense phase. As in gas-liquid systems, the bubble flow in the fluidised bed induces solids transport and mixing in the dense region. The upward velocity of air/combustion gases is 2 – 3 m/s, and bed heights are 0.5 to 1.5 m. Solid materials mostly stay in the well stirred bed, although small particles will leave the bubbling bed and be thrown up into the freeboard region. Cyclones and other particulate removal equipments are used to collect them before the flue gas is channelled to the heat recovery systems. Coarse bed material is also withdrawn from the bottom of the bed to maintain high sulphur-capture capacity and to avoid ash contamination which might cause bed agglomeration (IEA-ETSAP, Biomass for Heat & Power 2010).

In Circulating fluidised bed combustion (CFBC) boilers, In CFBC, a distinction between the bed and the freeboard area is no longer applicable. A large fraction of the particles rises up from the bed and is re-circulated by a cyclone. The circulating bed material is used for temperature control in the boiler. The choice between BFBC and CFBC depends inter alia on the fuel used. CBFC boilers are used in smaller biomass-fired plants.

Table 1-2 presents technical performance, including in some cases steam quality, data of some biomass-fuelled power plants in Europe. Most of them burn wood, forestry residues, or waste wood.

Table 1-2: Technical features of biomass power plants (IEA-ETSAP, Biomass for Heat & Power 2010)

Country	Operator	Start Year	Technology	Electric Eff`	Capacity	Steam Quality
				[%]	MWe	
Belgium	A&S	2010	N/A	N/A	24	
Germany	RWE	2002	VG	16.5	8.7	
France	Solvay	2010	N/A	N/A	30.0	
Hungary	DBM	2009	VG	N/A	19.8	
Hungary	BHD	2010	N/A	31.5	49.9	
NL	RWE	2002	BFBC	29.9	25.0	
Portugal	N/A	1999	VG	26.5	9.0	
Spain	EHN	2003	VG	32.0	25.0	92 bar/542°C
UK	E.On	2008	BFBC	31.3	43.9	137 bar/537°C
UK	Prenergy	2011	N/A	36.0	350.0	
UK	RWE	2012	N/A	N/A	50.0	
UK	E.On	2011	N/A	N/A	25.0	
UK	RWE	2011	N/A	N/A	65.0	
UK	Helius	2012	N/A	N/A	100.0	
UK	E.On	2013	N/A	N/A	150.0	
UK	MGT	2012	N/A	N/A	295.0	
UK	RES	2015	N/A	N/A	100.0	
UK	Eco2 Ltd	2009	VG	N/A	13.8	
UK	Eco2 Ltd	2011	VG	N/A	40.0	
UK	EPR Ely	2000	VG	32.0	38.0	

Biomass-fuelled plants with capacities of 25 MWe or more usually have advanced steam parameters and high efficiencies (IEA-ETSAP, Biomass for Heat & Power 2010).

1.7.2 Co- firing of biomass in coal-fired power plants

Biomass co-firing in coal-fired power plants is highly efficient. Depending on the efficiency of the coal-fired unit (39% - 46%), it can yield efficiencies of between 36% and 44%; coal-fired power plants have coal access facilities, which may also facilitate biomass supply; they also have advanced flue gas cleaning equipments, which in some cases may obviate separate cleaning for biomass (IEA-ETSAP, Biomass for Heat & Power 2010).

Biomass co-firing in coal power plants requires significant boiler retrofitting, as well as specific equipment and space for biomass logistics, and tailoring of flue gas cleaning equipment (i.e. electrostatic precipitator, flue gas desulphurisation, and de-NO_x, if applicable), especially if significant amounts of biomass are co-fired. NO_x emissions in coal/biomass co-firing depend significantly on the emission reduction technology. NO_x emissions of 150 – 300 mg/Nm^3 have been reported, which are equivalent to 400 –800 gNO_x/MWh. For a retrofitted coal-fired power plant in Poland, NOx emissions are less than 200 mg/Nm_3, equivalent to 500 g NO_x/MWh (IEA-ETSAP, Biomass for Heat & Power 2010).

Biomass co-firing may reduce NO_x emissions compared to coal as biomass has lower nitrogen content. Co-firing technology options include:

- Direct Co-firing with pre-mixed biomass and coal, co-milling and co-firing;
- Direct Co-firing with pre-milled biomass to the coal firing system or furnace;
- Indirect co-firing with biomass gasification and fuel gas combustion;
- Parallel co-firing with biomass combustion in a separate combustor and boiler.

The use of biogas is gaining importance in Germany, the Netherlands, the United Kingdom, and Italy. Biogas may also be upgraded to be mixed with natural gas and used in natural gas grids or to power vehicles as compressed natural gas (CNG) (IEA-ETSAP, Biomass for Heat & Power 2010).

1.7.3 Biomass Gasification

Pressurised gasification in an integrated gasification combined cycle (IGCC) is one of the high efficiency technologies which could reduce emissions, including greenhouse gas CO_2, from large scale power production based on solid fuels. Peat is an ideal fuel for gasification because of its high volatile content. The present status in developing biomass-fired IGCC technology in the Nordic countries is such that a demonstration unit is currently under construction in Sweden. The gasification of straw has only been tested successfully when done together with coal, so the gasification of straw alone needs further development before it could be commercially available (BREF, 2006).

The biomass updraft gasification technology (see Figure 1-16) has been developed for three main reasons (Teislev 2006):

- The inhomogeneous process of mass combustion is changed into the more attractive process of burning a homogeneous gas
- The product gas may – after a modest clean-up – be burned using Low-NOX gas burner technology in connection with indirectly fired power cycles like the Indirectly Fired Gas Turbine (IFGT) and the Stirling Engine
- After adequate cleaning the product gas may even be used for direct firing of gas-turbines and internal combustion engines

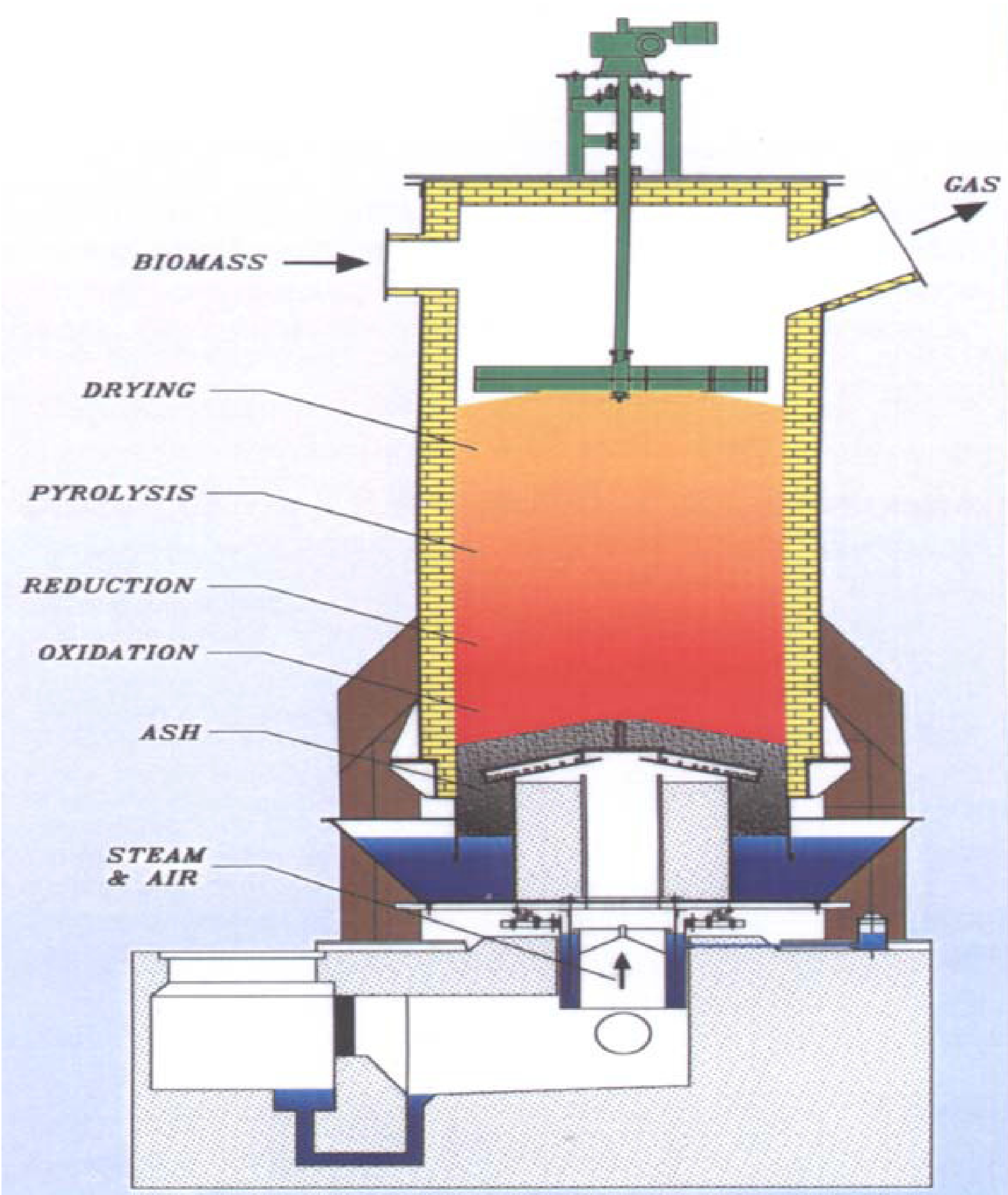

Figure 1-16: Updraft Gasification Principle

Fresh wood-chips (typically 40 – 50% moisture content) is dried in counter-flow with hot rising product gases passing the ”fibre saturation point” (at about 23% moisture) after which changes in wood structure – and also thermophysical properties – appears. At the same time the product gases are cooled to a temperature of 73 – 75°C. The drying process takes place in the temperature range up to about 160°C. In the pyrolysis section, the major polymers (Cellulose, Hemicellulose and Lignine) are broken down into typically (dry wood basis, weight): 15% CO, 18% CO_2, 6% CH_4, 11% H_2O and 30% tars. A solid – highly reactive – char residue of typically 20% containing some H2 is produced during this process taking place in the temperature range 120°C to 600°C. In the elevated temperatures of the reduction (gasification) section the char produced in the pyrolysis zone is reacting with H_2O and CO_2 to form (mainly) H_2, CO and CO_2 through several endothermic processes in the temperature range 500°C to 1100°C. Through the addition of oxygen (typically air) a part of the char descending from above is reacts with O_2 (and also through an intermediate stage with CO) to create heat (exothermic processes) at temperatures above 1000oC for the processes in the previous processes. The amount of combustion typically corresponds to an overall process stoichiometry of 26 – 29% (Teislev 2006).

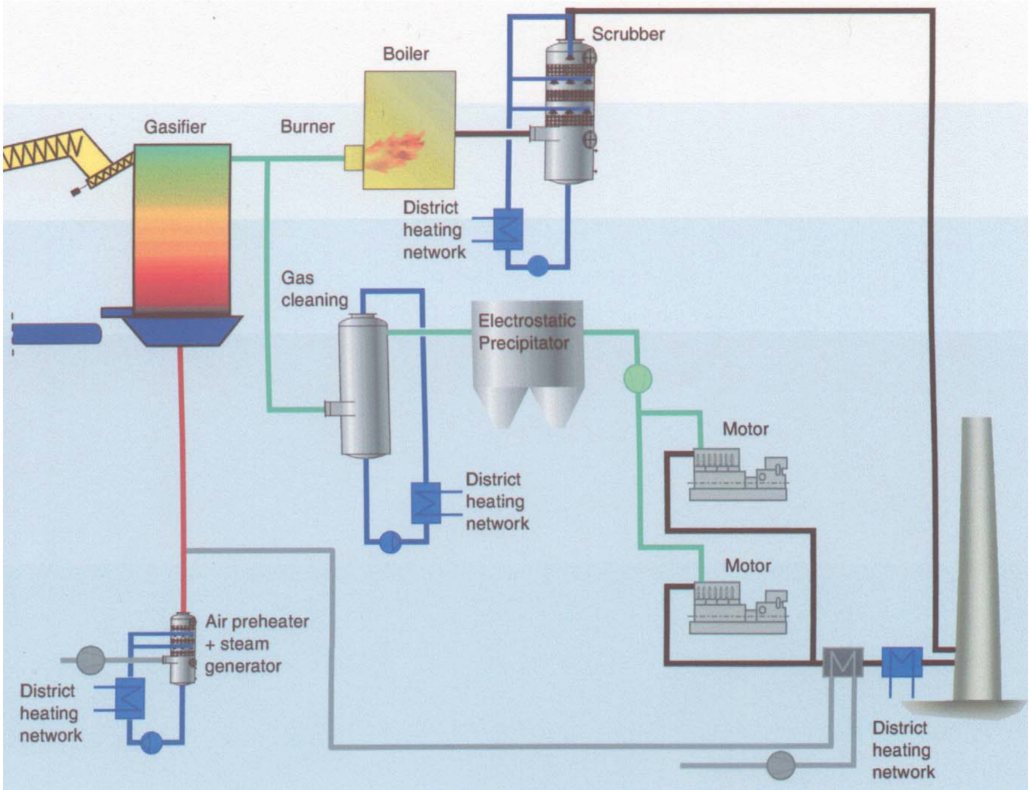

Figure 1-17:Schematic diagram of the Babcock & Wilcox Volund 1500 kW_E power and 3200 kW_{TH} wood-chips updraft commercial gasifier at Harboore (Westcoast Jutland, Denmark) (Teislev 2006)

An example of a commercial installation of an updraft gasifier is shown in Figure 1-17. At nominal conditions the wood-chips fuel input is 4800 kW_{TH}, which is transformed into 1500 kW_E power and 3200 kW_{TH} district heating (operated at forward temperature 90^{o}C and return temperature 40^{o}C). Therefore, the power efficiency (from wood-chips to electricity) is about 31% (Teislev 2006).

Today's maximum efficiency of a pulverised coal-fired power (PC) plants is around 46%, with potential for reaching 50% or more by 2020. Respective Figures for integrated gasification combined cycles (IGCC) are 46% and 52%. Because of the smaller size, neither biomass power plants nor biomass integrated gasification combined cycles (BIGCC) can attain efficiency as high as co-firing. The BIGCC technology also requires significant RD&D before its full commercialisation (2020) (IEA-ETSAP, Biomass for Heat & Power 2010).

1.7.4 Barriers

Biomass power generation faces some challenges that mostly relate to the quality, availability and supply chain of biomass. In a typical thermal power station, the basic fuel is prepared to the specific size, according to the technical requirements of the boiler furnace in order to ensure efficient combustion. The boiler furnaces are specifically designed to suit the characteristics and parameters of the fuel (coal or gas) on which the system is proposed to run. The availability of this specific fuel is ensured by the user well in advance through techno-legal agreements with fuel suppliers, for guaranteed supply of the fuel in the specified quality and quantity. In the case of biomass projects, no such agreements exist as biomass fuel market is unorganized and rural based.

A more critical issue is that of the wide variation in the sizes of the biomass as it is received, poses another bottleneck. This calls for an additional process of appropriate sizing of the bio mass. However, the wide variation and seasonality in the availability of the bio mass, and their basic characteristics, (size, shape, texture, moisture content, volatile matter, Calorific Values, etc.) make effective preparation of biomass to suit the boiler technical requirements, a very complex exercise. Consequently the efficiencies of the boilers would be low as compared to a boiler operating with a single fuel, for which the basic operating parameters can be set once. This is very difficult with multi-fuels scenario with frequently changing mix. In fact, this seems to be one of the reasons, for several biomass based cogeneration projects, to have opted for higher heating surface area, compared to the well established fossil fuel based power plants (of equivalent rating).

The poor quality of biomass in terms of high moisture content, low calorific value and low bulk density, often results in low heat generation in the boiler, which cannot sustain power generation at the rated capacity. This problem gets further aggravated during the rainy season. Also, unavailability of sufficient biomass, due to seasonal constraints, necessitates co-firing of fossil fuels such as coal, to maintain the required steam parameters and/or power generation. While use of coal as a supplementary fuel is allowed, care should be taken with regards to the quality of the coal, and it should be of a low quality or it would result in high bed temperature and subsequently choking of the bed due to ash fusion.

Compared to coal based power plants, biomass based power plants operate with higher heat rate (low efficiency) due to poor fuel quality (high moisture and low GCV), lack of optimization of boiler parameters and the turbine parameters (such as optimization of excess air and steam parameters). Fouling of heat transfer area due to unavoidable dust loading in the boiler furnace (due to inherent biomass properties) is another reason why the biomass-based plants operate with higher heating surface area. The overall heat transfer coefficient, especially in closely packed convective zone, would deteriorate gradually with time and spare heat transfer area in these situations, would help maintain required heat transfer (UNEP-DTIE 2007).

1.8 CONCENTRATED SOLAR POWER GENERATION

Solar energy can be used as the heat source in a thermodynamic cycle to produce power. The temperatures that can be achieved with flat plate solar collectors would be in principle enough for this purpose. In this case an Organic Rankine Cycle would be used for power generation. Nevertheless, such low temperature systems have very modest efficiencies. Higher temperatures can be achieved with concentrating solar collectors. These can supply the needed thermal energy for a conventional steam turbine (Rankine cycle), and even for a gas turbine (Brayton cycle) or a Stirling engine in the case of higher concentration factors.

Concentrating Solar Thermal (CSP) technologies have much in common with fossil fuel power plants. The main difference is the source of the heat, which is solar in one case and the result of combustion in the other. CSP plants can also be built hybrid, i.e. integrate a combustion system. An important indicator in the operation of such power plants is the solar factor, which is the share of solar power generation in the total electricity output in one year.

A CSP plant consists of the concentrator system, a solar receiver and the power block. Depending on the CSP technology a heat storage system can be included.

There are four solar concentration technologies applied in CSP, all of them are reflective: The parabolic trough, the linear Fresnel concentrator, the power tower and the dish. The first two are line focus technologies and the later are point focus technologies. Point focus technologies have a much higher concentration factor and can achieve therefore higher temperatures and have therefore the potential for higher efficiencies.

The most advanced CSP technology today is the parabolic trough power plant. Between 1985 and 1991, 354 MW of such power plants were built in southern California. They are still under commercial operation today, demonstrating the long-term viability of the technology. Newer power plants are the Nevada Solar One, a 64 MW facility that went in operation in 2007, and the 50 MW Andasol power plant in Spain, that went in operation in 2008.

The concentration factor of parabolic trough power plants is 70 to 100. In this layout long rows of parabolic trough reflectors concentrate the sunlight on a receiver placed along the focal line. The sun is tracked around one axis, typically oriented north-south. The receiver consists of a steel pipe, coated with a solar selective surface and an outer glass tube, with vacuum in between to minimize heat loses. Thermal oil flows through the steel pipe and is thereby heated to around 390°C. The hot oil flows from the solar field to the power block where it generates in a heat exchanger steam for a Rankine cycle. An alternative to thermal oil as a heat transfer fluid is the use of water for direct steam generation. Eliminating the need for thermal oil reduces costs and overcomes the environmental impact related to oil leakage. It would also eliminate the need for a heat exchanger in the power block as the heated water in the solar field is flashed and flows directly in the steam turbines. This issue of direct steam generation, which implies a two-phase flow, has still some technical challenges to be overcome before achieving commercial application, especially taking into account that the receiver is moving with the solar tracking.

Parabolic trough power plants could also integrate a thermal storage system, which accumulates heat from the solar field in sunny hours to release it later for power generation. New plants are being designed with around 7 hours of full-load storage, which is enough to allow operation well into the evening when peak demand can occur and tariffs are high. Molten salt is used for thermal storage. The system integrates a hot and a cold tank with a heat exchanger in between.

An alternative to the parabolic trough reflector is the linear Fresnel reflector, which has lower installed costs on a m^2 basis, but also a lower annual optical performance. In this concentration system the receiver is fixed, which makes direct steam generation an easier issue.

The power tower is a point focus CSP technology with a concentration factor roughly in the range of 800 to 1500. This technology uses an array of heliostats that track the sun reflecting its beam onto a fixes receiver on the top of a tower. A temperature of 1000°C and above can be reached in the receiver. The power tower technology has been initially applied together with a Rankine cycle, but current research is focusing on a Brayton cycle approach. This would eliminate the need for cooling water, which is a big advantage considering the potential application sites of CSP. On the other hand, efficiencies can be boosted to above 50% if a combined cycle is used. On the other hand, higher temperatures make thermal storage more challenging. This issue remains on the research level.

The receiver technology is a very important research topic in power tower development. A number of receivers have been developed for different heat transform fluids. Approaches for direct steam generation started on the early days of this technology, however, with major technical difficulties due to operation interruptions through clouds. Molten salt has been then applied in a receiver composed of vertically located tubes. The salt is then used for direct power generation or for heat storage. An important technical issue in this technology is to avoid the salt from freezing in the pipes. Therefore, these have to integrate electrical resistance for heating the pipe in this case. More recent receiver technology focuses on the use of air as a heat transfer fluid. Such receivers have gained importance with the interest in higher temperature approaches, for instance to shift from a Rankine cycle to a Brayton cycle.

Dish reflectors are parabaloid-shaped and concentrate the sun into a point focus. Two axis tracking is required. Dishes have been used to power Stirling engines at 900°C. Although in the 1980s dish-striling units of 50 kWe nominal power have been built, currently units up to 25 kWe are rather the standard. In a Dish-Stirling system the receiver is an integral element of the engine.

1.9 NUCLEAR FISSION POWER GENERATION

1.9.1 Present situation

In January 2011 the installed nuclear electricity capacity in the EU was 130 GWe, which contributed one third of the generated electricity in the EU (Euronuclear 2011). Most of the current designs are Light Water Reactors (LWR) of the second generation.

As of today the state of the art of commercial nuclear power reactors are of the third generation. Examples of such reactors are the European Pressurized Water Reactor (EPR) by Areva, the Advanced Boiling Water Reactor (ABWR) by General Electric, and the Advanced Pressurized Water Reactor (APWR) by Mitsubishi Heavy Industries etc. Currently there are four ABWRs operating in Japan. In the EU there are two EPRs under construction in Finland and France, targeted for connection to the grid in 2013 and 2014, respectively (Wikipedia- EPR 2011). Two EPRs are also under construction at Taishan in China (Wikipedia- EPR 2011).

The EPR is an evolution of the French N4 and German KONVOI reactor designs. Its electrical power is 1650 MW and the thermal power 4500 MW, i.e. the thermal efficiency is about 36-37%. The EPR is designed for a 60 year lifetime (Areva- EPR 2005). As the name implies the EPR is operating under pressurized conditions, usually around 155 bar, which means that the water is not allowed to boil in the primary circuit. The temperature at core inlet is 275°C and at outlet 315°C.

It employs a Rankine cycle, in which, the heat produced in the reactor core is transferred from the primary to secondary circuit via four parallel loops, each one equipped with a steam generator and a coolant pump, see Figure 1-18.

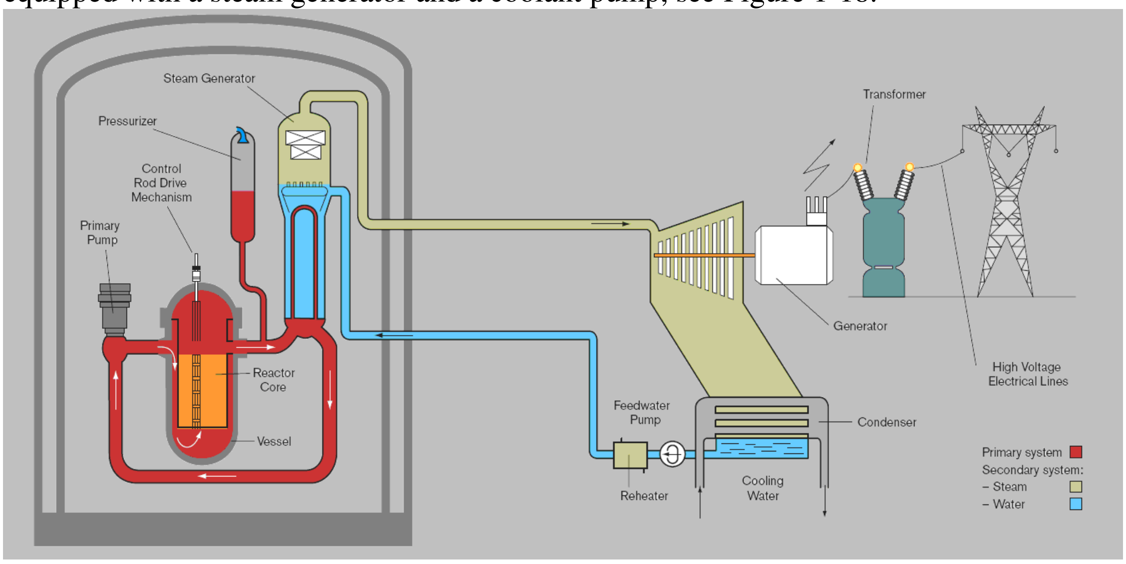

Figure 1-18. Schematic view of EPR (Areva- EPR 2005)

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The steam generated in the steam generators on the secondary side is then routed to the turbine, which drives the generator.

An overview of the building arrangement of the EPR can be found in Figure 1-19. The nuclear island stands on a single concrete base-mat in order to withstand earthquakes better. The EPR is designed to withstand both military and large commercial airplane crashes, by the construction of an outer and an inner reinforced concrete shell of 1.3 m thickness each. Also buildings are protected through physical separation. This holds for the diesel generators as well.

The steam generated in the steam generators on the secondary side is then routed to the turbine, which drives the generator. An overview of the building arrangement of the EPR can be found in Figure 1-19.

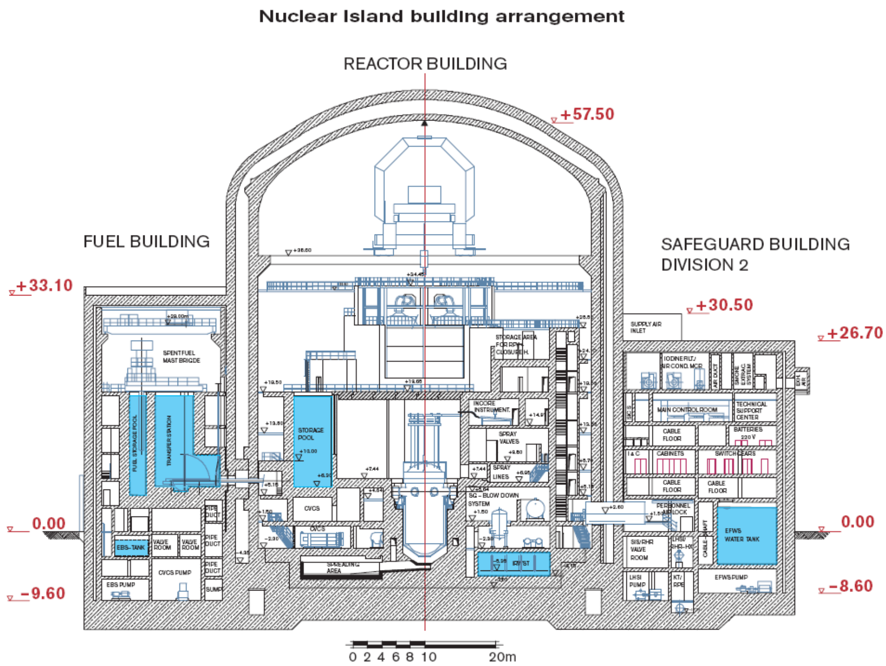

Figure 1-19: Building arrangement of EPR (Areva- EPR 2005).

The safety systems are designed with quadruple redundancy, which means that each system is made of four systems that are capable by themselves to fulfil the whole safeguard function. Also these are physically separated from each other by being located in different buildings.

Availability of the EPR is expected to be 92%, thanks to longer irradiation cycles and shorter refuelling periods. A Generation II reactor of today has on average an This is partially achieved through the quadruple redundancy of safeguard systems mentioned above, which allows for that maintenance is being performed while the reactor is operating.

1.9.2 Future

Since uranium resources are limited and expansion of nuclear power is expected on a global level new reactor types might be needed, which can use the uranium fuel much more efficiently. These reactors, called fast reactors due to their faster neutron spectra, have been under development for decades. In Europe all large nuclear nations have had fast reactors programs in the past, e.g. Germany, UK, France, and Italy. However, after the TMI and Chernobyl accidents these programs were stopped. Interest in fast reactors has grown again with the launch of Generation IV reactor concepts (DoE 2002). Six reactor concepts are being studied who all have their specific objectives. The concepts are the Sodium-cooled Fast Reactor (SFR), the Lead-cooled Fast Reactor (LFR), the Gas-cooled Fast Reactor (GFR), Very High Temperature Reactor (VHTR), Molten Salt Reactor (MSR), and the Super-Critical Water Reactor (SCWR). Today the SFR is the most mature concept. In Europe, a concerted effort is being implemented in the form of a European Sustainable Nuclear Industrial Initiative (ESNII) as part of the Community's SET-Plan (JRC-SETIS 2009). In ESNII the SFR is the primary system with construction of a prototype of 250 – 600 MW_e in France to be operational by 2023 (SNETP 2011). In parallel, a gas- or lead-cooled fast reactor (GFR/LFR) will also be investigated and possibly demonstrators constructed. The VHTR is a concept which has as one of its primary objectives to cogenerate both electricity and heat.

2 HEAT GENERATION

2.1 BOILER TECHNOLOGY

A combustion boiler (or steam generator) consists of fossil fuels or biomass burner and a heat-transfer system to boil water and generate steam. Steam generators also include systems and components for pressure control, heat recovery, steam delivery and distribution, condensate drainage, and separation of oxygen and non-condensable gases.

According to (IEA, 2010), boilers can be grouped into two broad categories: water-tube boilers and fire-tube boilers. In the water-tube boilers, tubes containing water are heated by combustion gases that flow outside the tubes, while in the fire-tube boilers hot combustion gases flow inside the tubes and water flows outside. In the current designs, the technology of choice is the water-tube design which is more suited to high-pressure steam generation as small tubes can withstand high pressure better and are less vulnerable to fracturing and failure.

Key design parameters to determine the boiler size and power are the output steam mass flow rate, pressure and temperature (saturated, superheated and super-critical steam).

IEA reports that in the industrialised countries, more than 50% of the industrial boilers use natural gas as the primary fuel (see Figure 2-1) and about 76% of the total boiler population is older than 30 years.

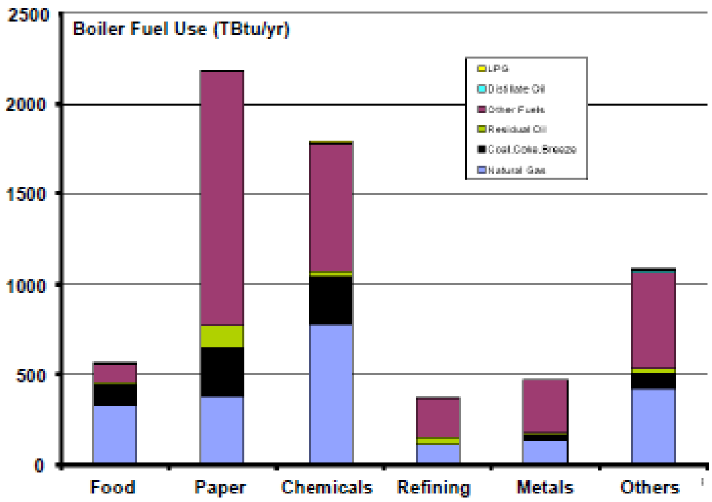

Figure 2-1: Boiler fuel use in the US industry by sector (IEA ETSAP 2010)

The energy efficiency is a major cost drive for boilers as the fuel cost accounts for more than 90% of the boiler overall costs on a life-cycle basis. Over the entire life-cycle, the fuel accounts for some 96% of the overall cost while capital, operation and maintenance (O&M) costs may represent as little as 3% and 1%, respectively. A typical cost of a gas- or oil–fired packaged fire-tube boiler that generates some 4695 kg/hr steam at 1.034 MPa is approximately € 43 000 (2008). An additional mass flow rate of 1565 kg/hr may result in a cost increase of around €333 3 900. This cost does not include components such as water softener, feed water system, chemical treatment equipment, economizer, blow-down equipment, condensate return system and fuel supply equipment. The installation cost may add between 50% and 100% to the investment cost. Information on investment, installation, operating and maintenance costs for power generation in the European Union can be found in the European commission staff working document Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport (EC, Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport, 2008).

New boiler efficiency varies with the type of fuel but also with the load factor (see Table 2-2). The efficiency of a steam generation can be improved by preventing or recovering energy losses (see Table 2-1).

Table 2-1: Efficiency improvement systems affect on boiler efficiency (ETSAP, Industrial Boilers 2010)

Efficiency improvement systems	Boiler Efficiency Increase %		
	Max	Min	Mean
Feed water pre-heating	1%	7%	5%
Combustion air preheating	1%	2%	1%
Pre-heat feed water with blow-down waste	1%	2%	1%
Insulation of pipes and valves	1%	2%	1%
optimal fuel/oxygen mix in the burner	1%	1%	1%

Table 2-2: New Boiler Efficiencies for different fuels (ETSAP, Industrial Boilers 2010)

Fuel	Boiler Efficiency %	
	Min Load	Max Load
Coal	75%	85
Oil	72%	80
Gas	70%	75
Biomass	60%	70

2.2 COAL

Coal-fired boiler efficiency is closely linked with the nature of the fuel and the temperature of the ambient air (the project-input data). However, optimisation of some parameters is possible:

- Unburned carbon in ash. Optimisation of combustion leads to less unburned carbon in ash. It should be noted that NOX abatement technologies by combustion modification show a tendency to increase unburned carbon. The target is to achieve the best burnout in order to achieve the optimum efficiency or fuel utilisation. However, according to technical and fuel characteristics in particular by burning anthracite coal, a higher content of unburned carbon in ash may occur;
- Air excess. Excess air is dependent on the type of boiler and on the nature of fuel. Typically, 20 % of excess air is the Figure for pulverised coal fired boiler with a dry bottom. Due to combustion quality (CO and unburned carbon formation), boiler integrity (air in-leakage), corrosion and safety (risk of thermal excursions in the boiler) it is often not possible to reduce the excess air any further;

• Flue-gas temperature. The flue- gas temperature leaving the clean boiler (depending in fuel type) traditionally lies between 120 and 220 °C so as to avoid the risk of acid corrosion by condensation of sulphuric acid. However, some designs sometimes incorporate a second stage of air heater to lower this temperature below 100 °C, but with special cladding on the air heater and the stack, which makes this reduction economically less attractive.

Gas-fired boilers are used as auxiliary boilers, to provide start-up facilities, including cold start possibilities in different types of thermal power plants. Auxiliary boilers are also applied in most power stations for heating buildings and equipment during standstill periods. These boilers are designed to produce slightly superheated steam at relatively low pressure. There are a lot of gas-fired boiler installations in process industries and in district heating systems. Most of them are medium sized installations (i.e. from 50 to 300 MW). For these levels of heat output, increasing constraints on SO_2 and NO_X emissions leads to a larger utilisation of natural gas. A large part of these boilers could also be fed with liquid fuel in emergency situations and for co-combustion.

The burners of the boilers are, in general, arranged in several levels in the walls (front firing or opposed firing) or at several levels tangentially in the four corners of the boiler. Firing systems for gas-fired boilers are similar to coal- or oil-fired boilers. Gas burners are also used in process heaters, which are sometimes referred to as process furnaces or direct-fired heaters. These are heat transfer units designed to heat petroleum products, chemicals, and other liquids and gases flowing through tubes. The liquids or gases flow through an array of tubes located inside a furnace or heater. The tubes are heated by direct-fired burners that use standard specified fuels such as HFO, LFO, and natural gas, or the by-products from plant processes, although these can vary widely in composition. Gaseous fuels are commonly used in most industrial heating applications in the US. In Europe, natural gases are also commonly used along with LFO. In Asia and South America, HFO are generally preferred, although the use of gaseous fuels is on the increase.

2.3 BIOMASS & WASTE

Based on up-to-date combustion technologies, biomass and waste also supply approximately 4.5 EJ (105 Mtoe) of direct heat to the industrial and residential sectors, and 2 to 3 EJ (47 to 70 Mtoe) of heat from combined heat and power (CHP) plants (IEA 2008).

The technology used to produced heat and stem from biofuels is similar to the one described in section 1.7. For the combustion of biomass and peat, pulverised combustion, fluidised bed combustion, (BFBC and CFBC) as well as the spreader stoker grate-firing technique for wood and the vibrating, water-cooled grate for straw-firing are considered. FBC technology took over the peat- and wood-firing market from pulverised- and grate-firing, so that now FBC is mainly used in new plants. These boilers typically have a fuel input of less than 200 MW, and they produce both electricity and heat to local industry or to the district heating system. The peat-fired boilers are usually also designed to combust other low calorific fuels, and sometimes coal. Heavy oil is commonly used as an auxiliary start-up fuel (B. IPPC 2006).

2.3.1 Municipal solid waste

Grate incinerators are widely applied for the incineration of mixed municipal wastes. In Europe approximately 90% of installations treating MSW use grates. Other wastes commonly treated in grate incinerators, often as additions with MSW, include:

commercial and industrial nonhazardous wastes, sewage sludge and certain clinical wastes. Grate incinerators (see Figure 2-2) usually have the following components:

- waste feeder
- incineration grate
- bottom ash discharger
- incineration air duct system
- incineration chamber
- auxiliary burners.

The waste is discharged from the storage bunker into the feeding chute by an overhead crane, and then fed into the grate system by a hydraulic ramp or another conveying system. The grate moves the waste through the various zones of the combustion chamber in a tumbling motion. The incineration grate accomplishes the following functions:

- transport of materials to be incinerated through the furnace;
- stoking and loosening of the materials to be incinerated;
- positioning of the main incineration zone in the incineration chamber, possibly in combination with furnace performance control measures.

Combustion takes place above the grate in the incineration chamber (see Figure 2.6). As a whole, the incineration chamber typically consists of a grate situated at the bottom, cooled and non-cooled walls on the furnace sides, and a ceiling or boiler surface heater at the top. As municipal waste generally has a high volatile content, the volatile gases are driven off and only a small part of the actual incineration takes place on or near the grate.

The following requirements influence the design of the incineration chamber (B. IPPC 2006):

- form and size of the incineration grate - the size of the grate determines the size of the cross-section of the incineration chamber;
- vortexing and homogeneity of flue-gas flow - complete mixing of the flue-gases is essential for good flue-gas incineration;
- sufficient residence time for the flue-gases in the hot furnace - sufficient reaction time at high temperatures must be assured for complete incineration;
- partial cooling of flue-gases - in order to avoid fusion of hot fly ash at the boiler, the flue gas temperature must not exceed an upper limit at the incineration chamber exit.

To achieve good burn out of the combustion gases, a minimum gas phase combustion temperature of 850 °C (1100 °C for some hazardous wastes) and a minimum residence time of the flue-gases, above this temperature, of two seconds after the last incineration air supply have been established in legislation (Directive 2000/76/EC and earlier legislation). Derogations from these conditions are allowed in legislation if they provide for a similar level of overall environmental performance (B. IPPC 2006).

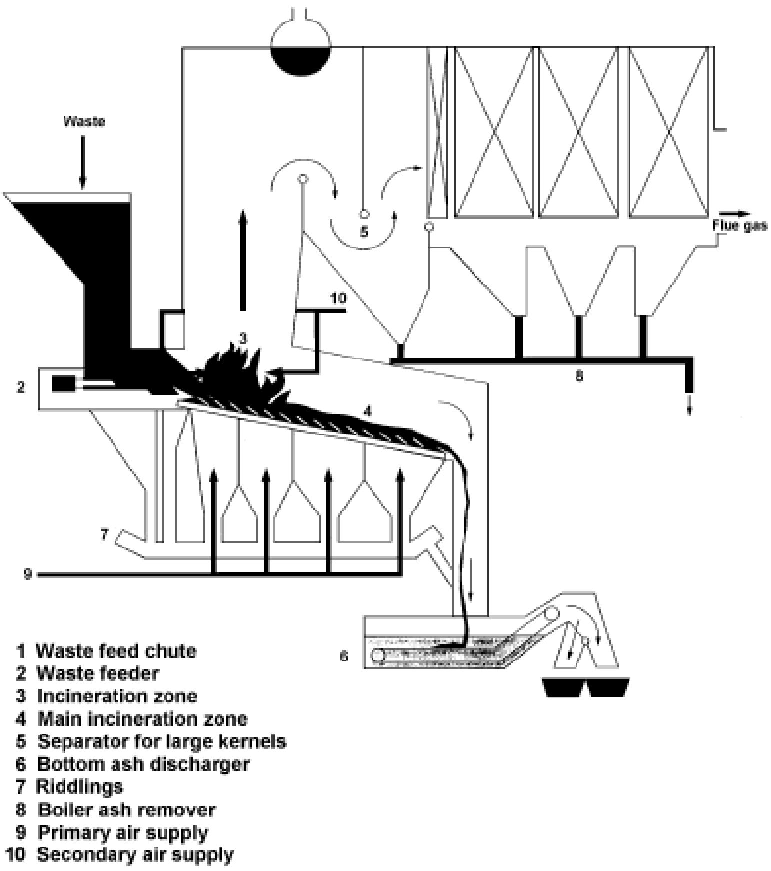

Figure 2-2: example of a grate incinerator with a heat recovery boiler (B. IPPC 2006)

2.3.2 Hazardous waste

Rotary kilns are, in particular, very widely applied for the incineration of hazardous wastes. The technology is also commonly used for clinical wastes (most hazardous clinical waste is incinerated in high temperature rotary kiln incinerators. Operating temperatures of rotary kilns used for wastes range from around 500 °C (as a gasifier) to 1450 °C (as a high temperature ash melting kiln). Higher temperatures are sometimes encountered, but usually in non-waste applications. When used for conventional oxidative combustion, the temperature is generally above 850°C. Temperatures in the range 900 - 1200 °C are typical when incinerating hazardous wastes. Generally, and depending on the waste input, the higher the operating temperature, the greater the risk of fouling and thermal stress damage to the refractory kiln lining. Some kilns have a cooling jacket (using air or water) that helps to extend refractory life, and therefore the time between maintenance shut-downs (B. IPPC 2006).

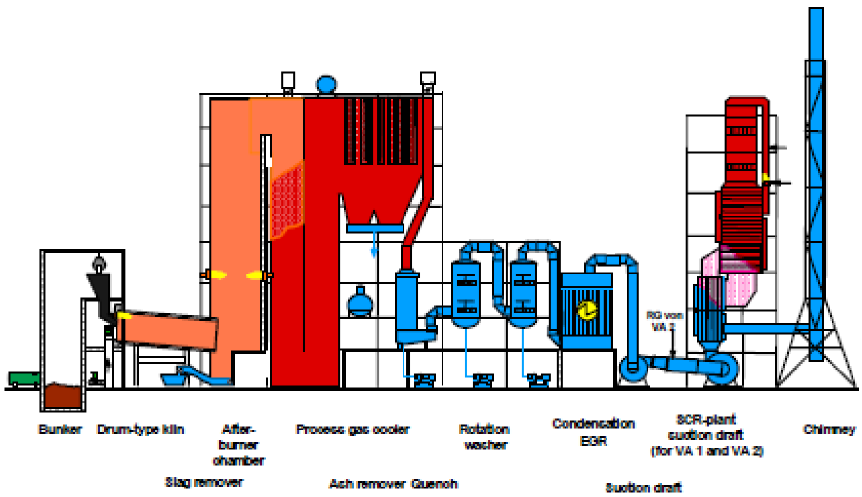

Figure 2-3: Rotary drum-type kiln plant for hazardous waste incineration (B. IPPC 2006).

The rotary kiln consists of a cylindrical vessel slightly inclined on its horizontal axis. The vessel is usually located on rollers, allowing the kiln to rotate or oscillate around its axis (reciprocating motion). The waste is conveyed through the kiln by gravity as it rotates. Direct injection is used particularly for liquid, gaseous or pasty (pumpable) wastes – especially where they have safety risks and require particular care to reduce operator exposure. Solid waste, liquid waste, gaseous waste, and sludge can be incinerated in rotary kilns. Solid materials are usually fed through a non-rotating hopper; liquid waste may be injected into the kiln through burner nozzles; pumpable waste and sludge may be injected into the kiln via a water cooled tube. In order to increase the destruction of toxic compounds, a post-combustion chamber is usually added. Additional firing using liquid waste or additional fuel may be carried out to maintain the temperatures required to ensure the destruction of the waste being incinerated. In order to increase the destruction of toxic compounds, a post-combustion chamber is usually added. Additional firing using liquid waste or additional fuel may be carried out to maintain the temperatures required to ensure the destruction of the waste being incinerated. For the incineration of hazardous waste, a combination of drum-type kilns and post-combustion chambers has proven successful, as this combination can treat solid, pasty, liquid, and gaseous wastes uniformly. Drum-type kilns between 10 and 15 metres in length, and with a length to diameter ratio usually in the range of 3 to 6, and with an inner diameter between one and five metres are usually deployed for hazardous waste incineration. Some drum-type kilns have throughputs of 70000 tonnes/yr each. In correlation to the average heat value of the waste, where heat recovery is carried out steam generation increases correspondingly (IPPC 2006).

Drum-type kiln plants are highly flexible in terms of waste input characteristics. The following range is usual in the composition of the waste input menu:

- solid wastes : 10 – 70 %
- liquid wastes: 25 – 70 %
- pasty wastes: 5 – 30 %
- barrels: up to 15 %.

2.3.3 Sewage sludge

Fluidised bed incinerators are widely applied to the incineration of finely divided wastes e.g. RDF and sewage sludge. It has been used for decades, mainly for the combustion of homogeneous fuels. Among these are coal, raw lignite, sewage sludge, and biomass (e.g. wood). The fluidised bed incinerator is a lined combustion chamber in the form of a vertical cylinder. In the lower section, a bed of inert material, (e.g., sand or ash) on a grate or distribution plate is fluidised with air. The waste for incineration is continuously fed into the fluidised sand bed from the top or side. Preheated air is introduced into the combustion chamber via openings in the bed-plate, forming a fluidised bed with the sand contained in the combustion chamber. The waste is fed to the reactor via a pump, a star feeder or a screw-tube conveyor. In the fluidised bed, drying, volatilisation, ignition, and combustion take place. The temperature in the free space above the bed (the freeboard) is generally between 850 and 950 °C. Above the fluidised bed material, the free board is designed to allow retention of the gases in a combustion zone. In the bed itself the temperature of is lower, and may be around 650 °C or higher. Because of the well-mixed nature of the reactor, fluidised bed incineration systems generally have a uniform distribution of temperatures and oxygen, which results in stable operation. For heterogeneous wastes, fluidised bed combustion requires a preparatory process step for the waste so that it conforms to size specifications. For some waste this may be achieved by a combination of selective collection of wastes and/or pre-treatment e.g. shredding. Some types of fluidised beds (e.g. the rotating fluidised bed) can receive larger particle size wastes than others. Where this is the case the waste may only require only a rough size reduction. An installation that pretreats mixed MSW for incineration in a fluidised bed incineration plant is shown in Figure 2-4 . Several pre-treatment stages are shown including mechanical pulverisation and pneumatic separation, along with the final stages of incineration, FGT and residue storage

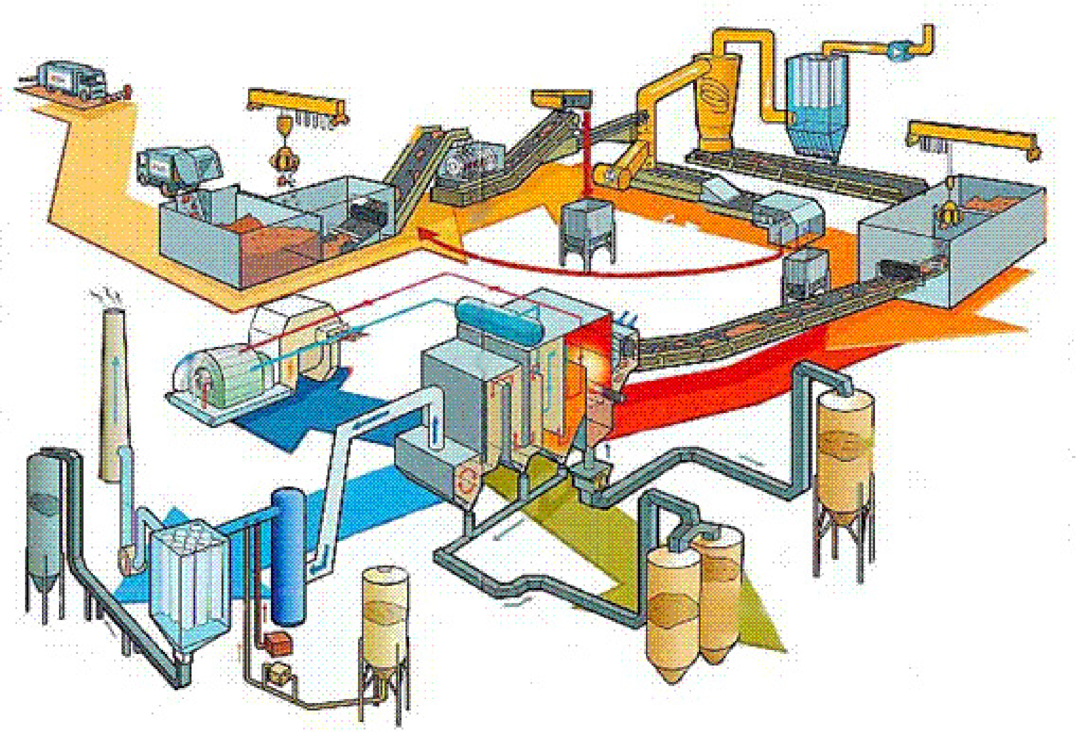

Figure 2-4: Schematic diagram showing pre-treatment of MSW prior to fluidised bed combustion (IPPC 2006)

The many pre-treatment steps that are shown in Figure 2-4 result in high investment costs of such installations. The relatively high cost of pre-treatment processes required for some wastes has restricted the economic use of these systems to larger scale projects. This has been overcome in some cases by the selective collection of some wastes, and the development of quality standards for waste derived fuels (WDF). Such quality systems have provided a means of producing a more suitable feedstock for this technology. The combination of a prepared quality controlled waste (instead of mixed untreated waste) and fluidised bed combustion can allow improvements in the control of the combustion process, and the potential for a simplified, and therefore reduced cost, flue gas cleaning stage (IPPC 2006).

Bubbling or circulating fluidised bed technology, atmospheric or pressurised, can be used for waste incineration. These technologies have been previously described (see Section 1.1.5).

2.3.4 Pyrolysis & Gasification

Both pyrolysis and gasification differ from incineration in that they may be used for recovering the chemical value from the waste (rather than its energetic value). The chemical products derived may in some cases then be used as feedstock for other processes. However, when applied to wastes, it is more common for the pyrolysis, gasification and a combustion based process to be combined, often on the same site as part of an integrated process. When this is the case the installation is, in total, generally recovering the energy value rather than the chemical value of the waste, as would a normal incinerator. Below are some reported waste pyrolysis-incineration, gasification-incineration and pyrolysis-gasification systems that have been reported (IPPC 2006):

1. Pyrolysis in a rotary kiln - coke and inorganic matter separation – incineration of pyrolysis gas;
2. Pyrolysis in a rotary kiln - separation of inert materials - combustion of the solid carbon rich fraction and the pyrolysis gas;
3. Pyrolysis in a rotary kiln - condensation of pyrolysis gas components - incineration of gas, oil and coke;
4. Pyrolysis on a grate - directly connected incineration;
5. Pyrolysis on a grate (with subsequent melting furnace for low metal content molten bottom ash production) - circulating fluidised bed (burnout of particles and gas);
6. Fixed bed gasifier - pre-treatment drying required for lumpy material;
7. Slag bath gasifier - as fixed bed but with molten bottom ash discharge;
8. Entrained flow gasifier - for liquid, pasty and fine granular material that may be injected to the reactor by nozzles;
9. Fluidised bed gasifier - circulating fluid bed gasifier for pretreated municipal waste, dehydrated sewage sludge and some hazardous wastes;
10. Bubbling bed gasifier - similar to bubbling fluidised bed combustors, but operated at a lower temperature and as a gasifier;
11. Conversion process - pyrolysis in a rotary kiln - withdrawal and treatment of solid phase - condensation of gas phase - subsequent entrained flow gasifier for pyrolysis gas, oil and coke;

12. Combined gasification-pyrolysis and melting - partial pyrolysis in a push furnace with directly connected gasification in packed bed reactor with oxygen addition (e.g. Thermoselect).

The principles of gasification technologies have described in Section 1.1.4. An example of an operating gasification system for the disposal of fluid hazardous waste is the entrained flow gasifier in Sekundärrohstoffverwertungszentrum (SVZ; Centre for Secondary Raw Materials Utilisation) at Schwarze Pumpe. The fluid wastes enter into the reactor via the burner system and are transformed into synthesis gas at temperatures of 1600 – 1800 °C. Since 1995, approx. 31000 tonnes of waste oil have been disposed of in this plant (IPPC 2006).
A waste gasification process based on fluidised bed in combination with current flow gasification is used in Japan. This process is designed to generate syn-gas from plastic packaging waste or other high calorific waste material. The main components of the process are a fluidised bed gasifier and a second stage high temperature gasifier. The fluidised bed enables rapid gasification of comparatively heterogeneous materials, which are pelletised for smooth feeding. Several per cent of non-combustible components, even metal pieces, are acceptable, as the ash is continuously discharged from the fluidised bed. The high temperature gasifier is designed as cyclone, to collect the fine ash particles on the wall. After vitrification the slag is discharged though a water seal. Both reactors are operated under elevated pressure, typically 8 bar. A first plant of this technology was under commercial operation in year 2001 to treat plastic packaging waste. The capacity of this demonstration plant is 30 tonnes per day. An additional plant of 65 tonnes per day started operation in 2002. The syn-gas produced is fed to an adjacent ammonia production plant. Other similar plants are under construction (IPPC 2006).

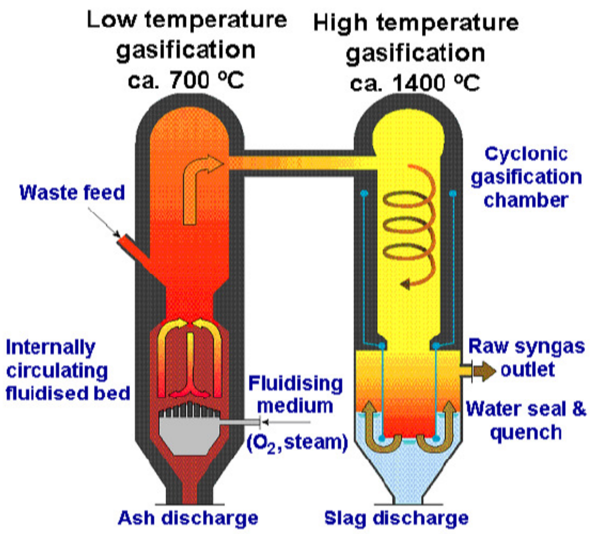

Figure 2-5: Fluidised bed gasifier with high temperature slagging furnace Source (IPPC 2006)

Pyrolysis is the degassing of wastes in the absence of oxygen, during which pyrolysis gas and a solid coke are formed.. As shown in Figure 2-6, pyrolysis plants for waste treatment usually include the following basic process stages (IPPC 2006):

1. preparation and grinding: the grinder improves and standardises the quality of the waste presented for processing, and so promotes heat transfer;

2. drying (depends on process): a separated drying step improves the LHV of the raw process gases and increase efficiency of gas-solid reactions within the rotary kiln;
3. pyrolysis of wastes, where in addition to the pyrolysis gas a solid carbon-containing residue accumulates which also contains mineral and metallic portions;
4. secondary treatment of pyrolysis gas and pyrolysis coke, through condensation of the gases for the extraction of energetically usable oil mixtures and/or incineration of gas and coke for the destruction of the organic ingredients and simultaneous utilisation of energy.

In general, the temperature of the pyrolysis stage is between 400 °C and 700 °C. At lower temperatures (approx. 250 °C) other reactions occur to some extent. This process is sometimes called conversion (e.g. conversion of sewage sludge).

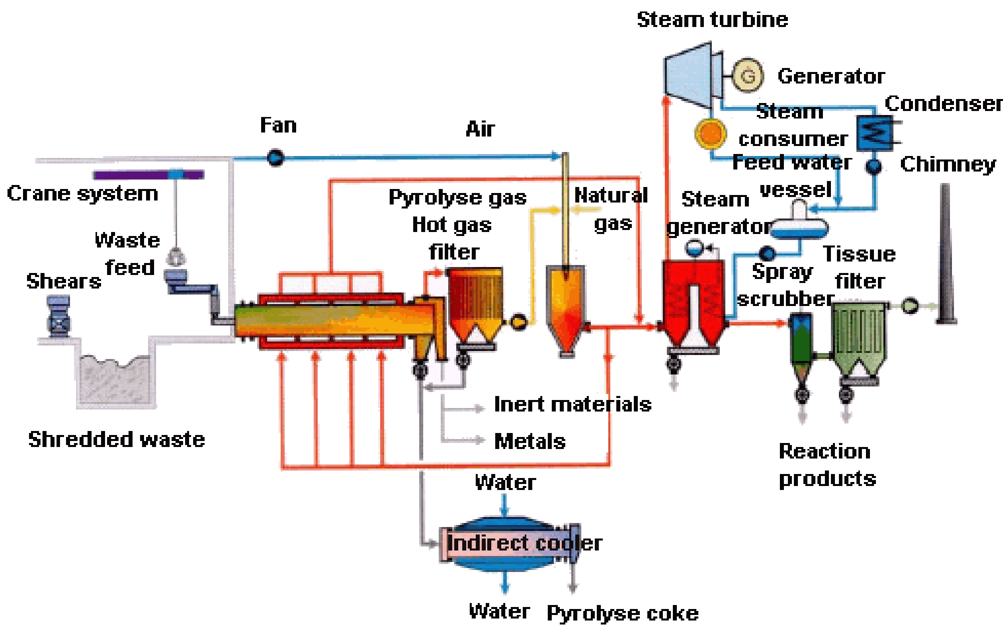

Figure 2-6: Schematic diagram of a pyrolysis plant for municipal waste treatment (IPPC 2006).

The potential advantages of pyrolysis processes may include:

- possibility of recovering the material value of the organic fraction e.g. as methanol;
- possibility of increased electrical generation using gas engines or gas turbines for generation (in place of steam boilers);
- reduced flue-gas volumes after combustion, which may reduce the FGT capital costs to some degree;
- possibility of meeting specifications for external use of the produced char by washing (e.g. chlorine content).

A pyrolysis plant for municipal waste treatment is operational in Germany, and another was due to start up at the end of 2003 in France. Other pyrolysis projects exist in Europe and elsewhere (notably in Japan) receiving certain specific types or fractions of waste, often after pre-treatment (IPPC 2006).

An example of a pyrolysis – combustion installation exists in the Netherlands and is used to treat hazardous clinical waste. Incineration takes place in a two-stage process (see Figure 2-7).

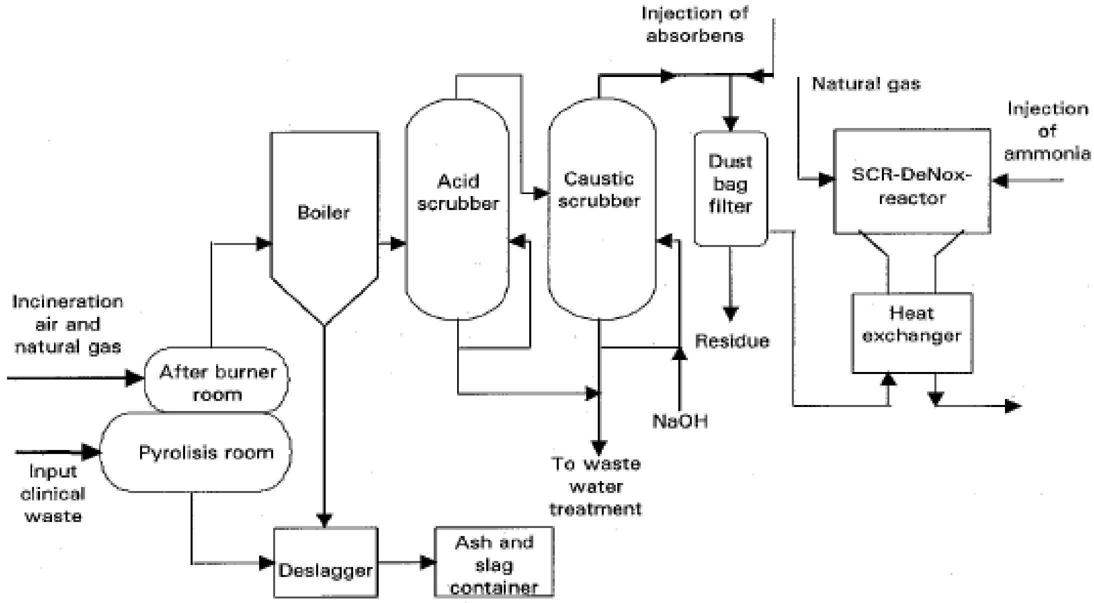

Figure 2-7: Schematic diagram of the ZAVIN pyrolysis – incineration plant for clinical waste in Dordrecht NL (IPPC 2006)

In the lower incineration room, a controlled pyrolysis occurs, followed by incineration with primary air as the waste progresses through the room. Finally, the waste ends in a water-filled ash discharger, from which the ash is removed by a chain conveyer system. The flue-gases are incinerated with secondary air and, if required, with auxiliary fuel at a temperature level of approx. 1000°C. Subsequently, they are cooled in a saturated steam boiler (steam temperature 225°C, pressure 10 bar), a heat-exchanger, and a scrubber. Steam is supplied to the adjacent municipal waste incineration plant which uses the steam and returns the related boiler feed-water. The scrubber is a two-stage system for removing acid compounds. The treated flue-gas is heated up (in a heat-exchanger and in a steam-flue-gas heat-exchanger) before passing a dust bag filter with adsorbent injection (activated carbon and lime), for removal of dioxins, and an SCR-De NOX unit. Emission concentrations of the emitted flue-gases are according to Dutch standards. The flue-gas is emitted through a 55-metre high stack (IPPC 2006).

A pyrolysis – gasification conversion plant for the treatment of 100000 tonnes/yr of municipal wastes and 16000 tonnes/yr of dehydrated sewage sludge was approved at Northeim, Lower Saxony, Germany (IPPC 2006).

A Combined gasification-pyrolysis and melting process plant of this type with a municipal waste throughput of 108000 tonnes/yr is currently under construction at Ansbach (Figure 2-8). Another plant with a throughput of 225000 tonnes/yr has been built at Karlsruhe Germany, but has not yet achieved the design throughput. Two plants of this type are operated in Japan (2003) (IPPC 2006).

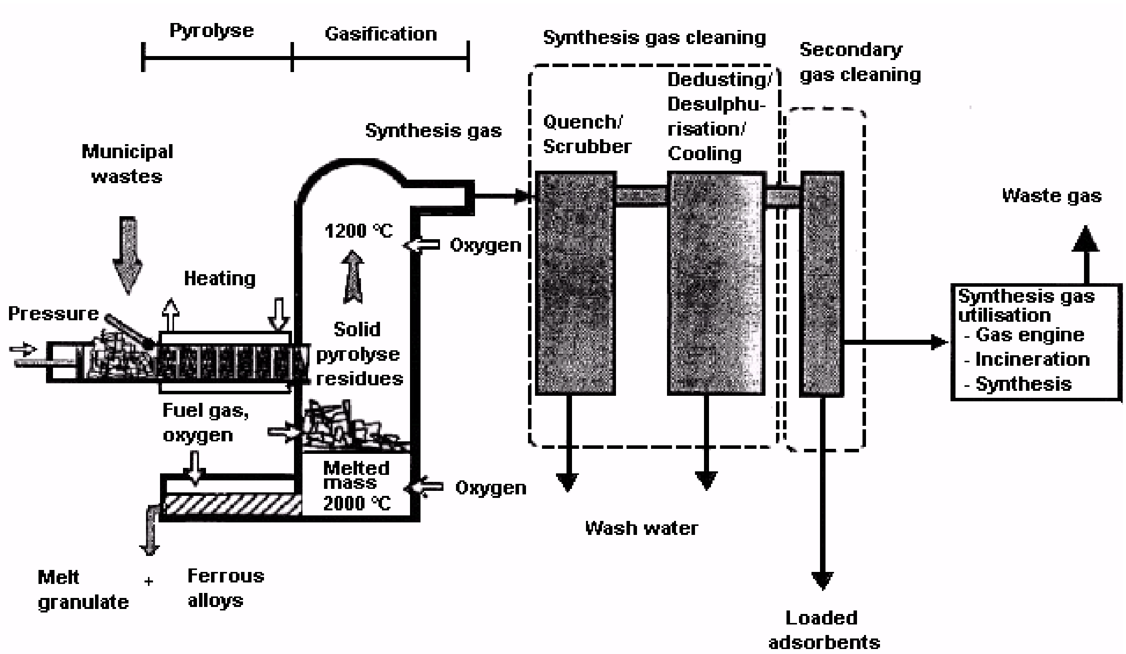

Figure 2-8: Schematic Diagram of a pyrolysis gasification waste treatment plant (Thermoselect) (IPPC 2006)

Another technique that is currently used is the incineration using multiple hearth furnaces. An example for the case of sewage sludge is given in Figure 2-9. The multiple hearth furnace consists of a cylindrical lined steel jacket, horizontal layers, and a rotating sleeve shaft with attached agitating arms. The furnace is lined with refractory bricks. The number of trays for drying, incineration, and cooling is determined based on the residual material characteristics. The multiple hearth furnace is also equipped with a start-up burner, sludge dosing mechanism, circulation-, sleeve shaft- and fresh air - blowers. Sewage sludge is fed at the top of the furnace and moves downwards through the different hearths counter-current to the combustion air, which is fed at the bottom of the furnace. The upper hearths of the furnace provide a drying zone, where the sludge gives up moisture while the hot flue-gases are cooled. The incineration mainly takes place on the central hearths. The incineration temperature is limited to 980°C, as above this temperature the sludge ash fusion temperature will be reached and clinker will be formed. In order to prevent leakage of hot toxic flue-gases, multiple hearth furnaces are always operated at a slight vacuum pressure. The conversion of organic sludge particles into CO2 and H2O occurs at temperatures of between 850 and 950°C. If the desired incineration temperature cannot be reached independently, a start-up burner is used for support incineration. As an alternative, solid auxiliary fuel can be added to the sludge. The ash is cooled to approximately 150°C at the lower layers of the furnace with counter-flowing cool air and the ash is removed via the ash system. The flue-gas that is produced is fed through a post-reaction chamber with a guaranteed residence time of two seconds. Carbon compounds that have not been converted are oxidised here.

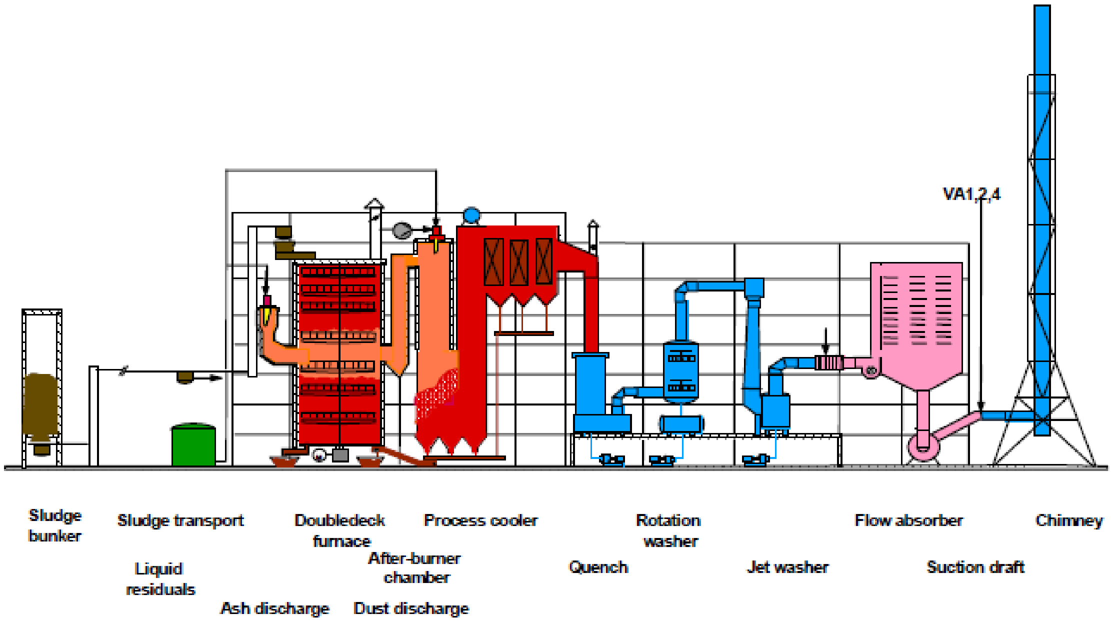

Figure 2-9: sewage sludge incineration plant with a multiple hearth furnace source (IPPC 2006)

Other techniques that are currently used are the multiple hearth fluidised bed furnace, and modular systems that are dedicated to specific kind of waste like Incineration chambers for chloride-containing wastes, Cycloid incineration chamber for sewage sludge, or for the incineration of caustic waste water (IPPC 2006).

According to (B. IPPC 2006), in waste incineration, fluidised bed technology is used in 15 - 30 MW heat and low pressure steam producing boilers uses approx. 35000 - 40000 tonnes per year of ready made recovered fuel. If it is made of commercial waste, demolition waste and separately collected packages from households, it can use all of this kind of material generated by a city of about 150000 inhabitants. The heat produced is about 150 GWh, which could be used by industry or for district heating.

Boilers of this size are very similar to operate to normal power plant boilers of 50 - 100 MW. Its behaviour is steady and uniform, because of the ready made controlled fuel made of sorted waste, and the heavy bed. When a suitable energy user is available an energy efficiency range of 70 - 90 % can be achieved. Rotating fluidised bed incinerators have been designed for thermal capacities from 10 - 55 MW (thermal) and corresponding waste throughput of 22000 - 167000 tonnes/yr per line. Energy is recovered by steam generators and used for electricity production and/or heating purposes depending on local requirements. Thermal efficiency is can be about 80 %, and electrical efficiency typically around 25 %.

In addition to waste quality and technical aspects, the possible efficiency of a waste incineration process is influenced to a large extent by the output options for the energy produced. Processes with the option to supply electricity, steam or heat will be able to use more of the heat generated during the incineration for this purpose and will not be required to cool away the heat, which otherwise results in reductions in efficiency.

The highest waste energy utilisation efficiency can usually be obtained where the heat recovered from the incineration process can be supplied continuously as district heat, process steam etc., or in combination with electricity generation. However, the adoption of such systems is very dependent on plant location, in particular the availability of a reliable user for the supplied energy.

The generation of electricity alone (i.e. no heat supply) is common, and generally provides a means of recovering energy from the waste that is less dependent on local circumstances. (IPPC 2006) gives approximate ranges for the potential efficiencies at incineration plants in a variety of situations.

Table 2-3: Energy potential conversion efficiencies for different types of waste incineration plants

Plant type	**Reported potential thermal efficiency % ((heat + electricity)/energy output from the boiler)**
Electricity generation only	17 – 30
Combined heat and power plants (CHP)	70 – 85
Heating stations with sales of steam and/or hot water	80 – 90
Steam sales to large chemical plants	90 – 100
CHP and heating plants with condensation of humidity in flue-gas	85 – 95
CHP and heating plants with condensation and heat pumps	90 - 100

The actual figures at an individual plant will be very site-specific. Doubts of calculation methods also make figures hard to compare – in this case the figures do not account for boiler efficiencies (typical losses ~ 20 %), which explains why figure approaching 100 % (figures exceeding 100 % are also quoted in some cases) are seen in some circumstances. The potential efficiencies are dependent on self-consumption of heat and electricity. Without taking the self-consumption into account, the calculated efficiencies of some facilities can lead to figures quoted of over 100 %. Distortions of efficiency figures are also common when boiler heat exchange losses are discounted (i.e. a boiler efficiency of 80 % means that 20 % of the flue-gas heat is not transferred to the steam, sometimes efficiency is quoted in relation to the heat transferred to the steam rather than the heat in the waste). Where there is no external demand for the energy, a proportion is often used on-site to supply the incineration process itself and thus to reduce the quantity of imported energy to very low levels. For municipal plants, such internal use may be in the order of 10 % of the energy of the waste incinerated. Cooling systems are employed to condense boiler water for return to the boiler. Processes that are conveniently located for connection to energy distribution networks (or individual synergistic energy users) increase the possibility that the incineration plant will achieve higher overall efficiencies.

2.4 GEOTHERMAL

In 2008, geothermal heating plants generated globally around 63 TWh of heat, with an installed capacity of approximately 18 GW_{th}. This is a very small fraction of the estimated global geothermal potential for direct heat use of 4400 GW_{th}. The economic feasibility of direct geothermal heat exploitation is limited by the distance between the consumer and the source.

Exploitation of geothermal resources for heat applications is obtained either by direct use of the resource or in combination with power generation as residual heat. Direct heat exploitation is basically in the low temperature range (<100C), as illustrated in Table 2-4. Applications like district heating require a relatively high temperature. For this purpose, resources with lower temperature could still be used in combination with a heat pump. However, such a system is most efficient when the required thermal rise is small. Ground-source heat pump (GSHP) for space and water heating is a mature technology. The geothermal heat exploitation could be horizontal or vertical. This last option is more expensive, as deep drilling is required (up to 250 m), but it's the only option by limited space.

Table 2-4: Geothermal resource utilisation potential for heat applications [Antics and Ugemach, 2009]

Application	Exploitation temperature [C]
Ground source heat pump	15 – 30
Balneology, medicinal	20 – 45
Fish farming, aquaculture	20 – 50
Space heating, greenhouses	35 – 65
District heating and cooling	50 – 100
Agro industrial uses	55 – 100
Process heat	60 – 100

The average investment cost for geothermal installations is around 1300 €/kW_{th}. The annual O&M cost is roughly 2% of the investment cost. The resulting energy cost is around 25 €/MWh. The investment cost could decline to around 1100 €/kW_{th} in 2020.

Several geothermal CHP options are available. For instance, for medium enthalpy resources, where the brine is a mix of water and steam, the steam can be separated and used for power generation while the remaining hot water can be used directly in heat applications. Much heat is also available in geothermal plants using an ORC. These are processes with relatively low input temperature and by that low electrical efficiency, so that very often they can only be economical if combined with heat use.

Geothermal CHP plants are economically viable where the demand for heat is significant and relatively constant along the year. This is for instance the case of Northern Europe, where much energy is demanded permanently for space and water heating.

2.5 SOLAR ENERGY HEAT GENERATION

As has been illustrated in the previous section (1.6), solar collectors can harvest solar radiation as heat at a wide range of temperatures. Flat plate collectors can be used for temperatures roughly up to 100°C. Line focus systems can supply heat at up to 400°C, while point focus system can even deliver 1200°C. This wide temperature range implies a wide variety of potential applications for solar energy. Nevertheless, in the praxis the use of solar energy for heat supply is rmostly limited to low temperatures, such as hot water for sanitarian use. Flat plate collectors are enough for this issue, and are widely applied worldwide. There are some applications with parabolic trough collectors to produce industrial heat. Application together with an absorption cycle is under research.

CSP plants can be used in cogeneration. One approach under investigation in parabolic trough power plants is to combine power generation and thermal seawater desalination. The desalination plant would use the heat in the condenser of the Rankine cycle. This option could emerge as attractive, especially taking into account that most potential application sites for CSP suffer fresh water shortage. Nevertheless, low temperature desalination would have to compete against Reverse Osmosis desalination in this application. Although there are some potential cogeneration applications for CSP, the nature of the technology, especially its remote location, makes the heat usage options shrink.

3 COGENERATION OF HEAT AND POWER

The conventional method of power generation and supply to the customer is wasteful in the sense that only about a third of the primary energy fed into the power plant is actually made available to the user in the form of electricity. The major source of loss in the conversion process is the heat rejected to the surrounding water or air due to the inherent constraints of the different thermodynamic cycles employed in power generation. Also further losses of around 10–15% are associated with the transmission and distribution of electricity in the electrical grid. In cogeneration, the production of electricity being on-site, the burden on the utility network is reduced and the transmission line losses eliminated. Cogeneration therefore makes sense from both macro and micro perspectives. At the macro level, it allows a part of the financial burden of the national power utility to be shared by the private sector; in addition, indigenous energy sources are conserved. At the micro level, the overall energy bill of the users can be reduced, particularly when there is a simultaneous need for both power and heat at the site, and a rational energy tariff can be practiced in the country (UNEP-DTIE 2007).

Co-generation uses a single process to generate both electricity and usable heat. Co-generation or 'the combined generation of heat and power' (CHP) is proven technology, and is mainly applied to industrial plants where both electricity and heat (hot water or steam) are needed. In addition to cost savings, co-generation also yields environmental benefits though using fossil fuels more efficiently. This leads to fewer emissions than the separate generation of electricity and heat, and also to optimised fuel and exergetic efficiency. Steam turbines driven by fossil fuel-fired boilers have been used for industrial co-generation systems for many years. High pressure steam raised in a conventional coal- or lignite-fired boiler is expanded within a turbine to generate mechanical energy, which can then be used to drive an electric generator. The amount of power generated depends on how much the steam pressure can be reduced though the turbine whilst still being able to meet the site heat energy needs. In some cases, the turbine is equipped with a separate or integrated low pressure cylinder, which enables electricity production independent of the heat supply.

Advantages:

- high overall fuel and exergetic efficiency
- any type of fuel can be used
- the heat and power ratio can be varied
- the ability to meet more than one site heat grade requirement
- high reliability and availability, usually better than 98 %
- wide range of sizes available
- long working life.

Disadvantages:

- high heat to power ratio
- high cost.

Steam turbines are the most commonly employed prime movers for cogeneration applications. In the steam turbine, the incoming high pressure steam is expanded to a lower pressure level, converting the thermal energy of high pressure steam to kinetic energy through nozzles and then to mechanical power through rotating blades. The different types of steam turbine include extraction cum condensing type and back pressure steam turbines.

The selection and mode of operation of the CHP system that will be implemented is very much related to the specific site conditions, and can follow different patterns. According to (UNEP-DTIE 2007), the CHP system can be designed to:

- Match the base electrical load; in this case the cogeneration plant is sized to meet the minimum electricity demand of the site based on the historical demand curve. The rest of the needed power is purchased from the utility grid. The thermal energy requirement of the site could be met by the cogeneration system alone or by additional boilers. If the thermal energy generated with the base electrical load exceeds the plant's demand and if the situation permits, excess thermal energy can be exported to neighbouring customers;

- Match the base thermal load; the cogeneration system is sized to supply the minimum thermal energy requirement of the site. Stand-by boilers or burners are operated during periods when the demand for heat is higher. The prime mover installed operates at full load at all times. If the electricity demand of the site exceeds that which can be provided by the prime mover, then the remaining amount can be purchased from the grid. Likewise, if local laws permit, the excess electricity can be sold to the power utility;

- Match the electrical load; the facility is totally independent of the power utility grid. All the power requirements of the site, including the reserves needed during scheduled and unscheduled maintenance, are to be taken into account while sizing the system. This is also referred to as a "stand-alone" system. If the thermal energy demand of the site is higher than that generated by the cogeneration system, auxiliary boilers are used. On the other hand, when the thermal energy demand is low, some thermal energy is wasted. If there is a possibility, excess thermal energy can be exported to neighbouring facilities;

- Match the thermal load; here the designed system meets the thermal energy requirement of the site at any time. The prime movers are operated following the thermal demand. During the period when the electricity demand exceeds the generation capacity, the deficit can be compensated by power purchased from the grid. Similarly, if the local legislation permits, electricity produced in excess at any time may be sold to the utility.

The cogeneration technology can be adopted in various industrial sectors such as textile, pulp and paper, brewery, food processing etc.). According to (UNEP-DTIE 2007), the first and basic requirement for implementation of cogeneration system is that the industry must require both steam and electrical power in its operations.

The ratio of the heat value of the steam required to the electricity required is known as heat to power ratio and is one of the most important factor which helps to decide the type and configuration of the cogeneration systems to be installed. Heat to Power Ratio is defined as the ratio of thermal energy to electricity required by the energy consuming facility. It can be expressed in different units such as Btu/kWh, kcal/kWh, lb./hr/kW, etc.

The heat-to-power ratio of a facility should match with the characteristics of the cogeneration system to be installed. Basic heat-to-power ratios of the different cogeneration systems are shown in Table 3-1: Heat to Power ratios and other parameters of cogeneration systems along with other technical parameters. The steam turbine cogeneration system can offer a large range of heat-to- power ratios.

Table 3-1: Heat to Power ratios and other parameters of cogeneration systems

Cogeneration System	Heat-to-power ratio (kWth/kWe)	Power output (as % of fuel input)	Overall efficiency (%)
Back-pressure steam turbine	4.0 – 14.3	14 – 28	84 – 92
Extraction-condensing turbine	2.0 – 10.0	22 – 40	60 - 80

Cogeneration is likely to be most attractive under the following circumstances (UNEP-DTIE 2007):

- The demand for both steam and power is balanced i.e. consistent with the range of steam: power output ratios that can be obtained from a suitable cogeneration plant;
- A single plant or group of plants has sufficient demand for steam and power to permit economies of scale to be achieved.
- Peaks and troughs in demand can be managed or, in the case of electricity, adequate backup supplies can be obtained from the utility company.

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 utilize supplementary or boost firing of the exhaust gases in order to modify the Heat to Power Ratio of the system to match site loads.

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 appropriate operating schemes 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. Table 6 shows typical heat: power ratios for certain energy intensive industries:

Table 3-2: Typical heat to Power ratio for energy intensive Industries with potential to biomass-fired CHP((UNEP-DTIE 2007)

Industry	Minimum	Maximum	Average
Breweries	1.1	4.5	3.1
Pharmaceuticals	1.5	2.5	2.0
Fertilizers	0.8	3.0	2.0
Food	0.8	2.5	1.2
Paper	1.5	2.5	1.9

3.1 STEAM TURBINE TECHNOLOGIES

3.1.1 Back Pressure Turbine

In this type of turbines (Figure 3-1), steam enters the turbine chamber at high pressure and expands to low or medium pressure. Enthalpy difference is used for generating power/work. Depending on the pressure (or temperature) levels at which process steam is required, backpressure steam turbines can have different configurations (Figure 3-2). In extraction and double extraction backpressure turbines, some amount of steam is extracted from the turbine after being expanded to a certain pressure level. The extracted steam meets the heat demands at pressure levels higher than the exhaust pressure of the steam turbine.

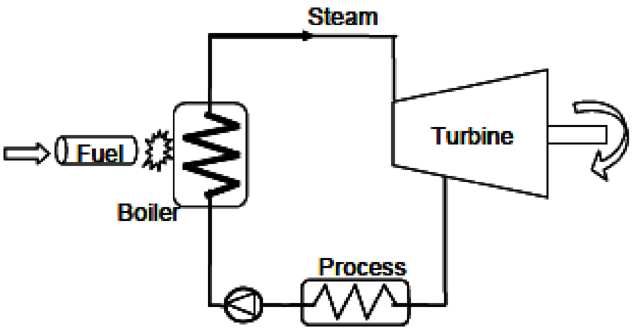

Figure 3-1: Back pressure turbine system (UNEP-DTIE 2007)

The efficiency of a backpressure steam turbine cogeneration system is the highest. In cases where 100% backpressure exhaust steam is used, the only inefficiencies are gear drive and electric generator losses, and the inefficiency of steam generation. Therefore, with an efficient boiler, the overall thermal efficiency of the system could reach as much as 90% (UNEP-DTIE 2007).

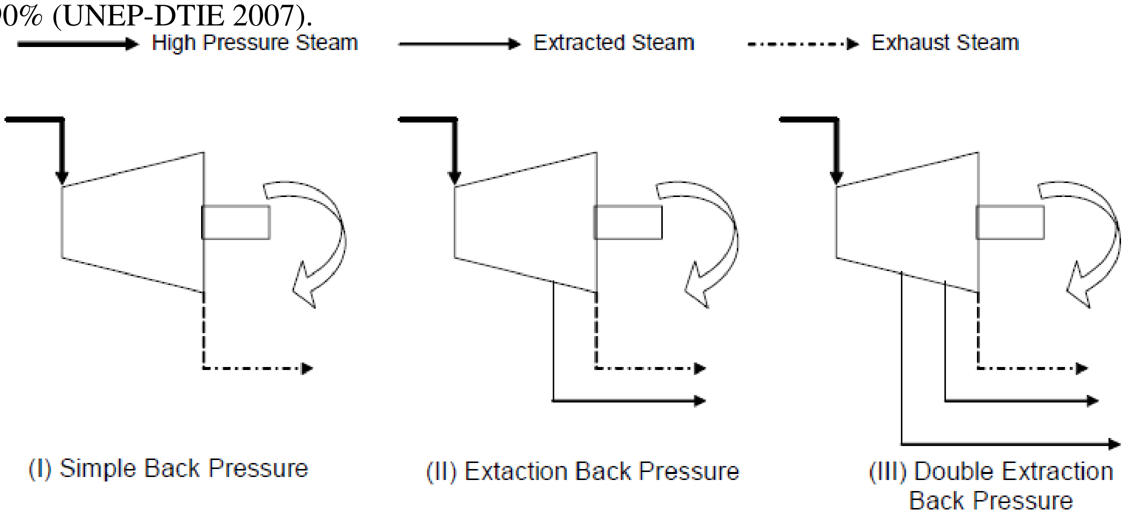

Figure 3-2: Possible configurations of back pressure turbine (UNEP-DTIE 2007)

3.1.2 Extraction Condensing Turbine

In this type, steam entering at high / medium pressure is extracted at an intermediate pressure in the turbine for process use while the remaining steam continues to expand and condenses in a surface condenser and work is done till it reaches the condensing pressure (vacuum).

In extraction-cum-condensing steam turbine (see Figure 3-3), high pressure steam enters the turbine and passes out from the turbine chamber in stages. In the process of two-stage extraction cum condensing turbine MP steam and LP steam pass out to meet the process needs. Balance quantity condenses in the surface condenser. The energy difference is used for generating power. This configuration meets the heat-power requirement of the process.

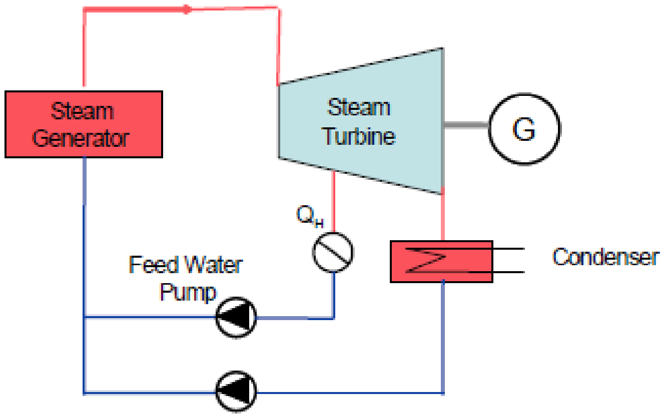

Figure 3-3: Extraction condensing turbine system (UNEP-DTIE 2007)

The extraction condensing turbines have higher power to heat ratio in comparison with back pressure turbines. Although condensing systems need more auxiliary equipment such as the condenser and cooling towers, better matching of electrical power and heat demand can be obtained where electricity demand is much higher than the steam demand and the load patterns are highly fluctuating.

The overall thermal efficiency of an extraction condensing turbine cogeneration system is lower than that of back pressure turbine system, basically because the exhaust heat cannot be utilized (it is normally lost in the cooling water circuit). However, extraction condensing cogeneration systems have higher electricity generation efficiencies.

3.2 FOSSIL FUEL – FIRED CHP

The most frequently used natural gas-based technologies are:

- Gas turbines with heat recovery steam generators (HRSG)(see Figure 3-4);
- 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;
- 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. Simple-cycle or combined-cycle gas turbines are largely used for industrial cogeneration.

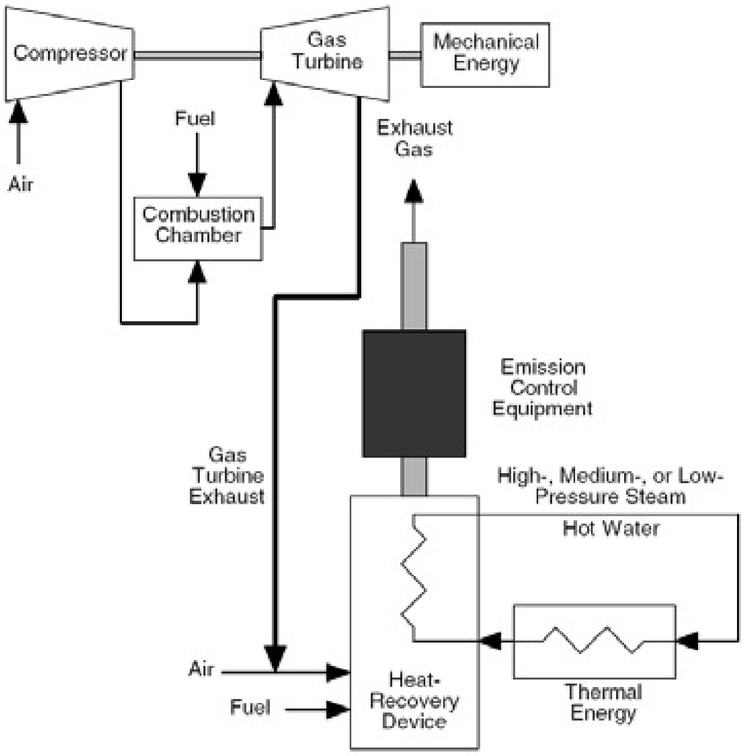

Figure 3-4: Gas-turbine CHP Plant (IEA-ETSAP, Combined Heat and Power 2010)

The PFBC system described in Section 1.1.5 can be used for cogeneration or combined cycle power generation. By combining the gas and steam turbines in this way, electricity is generated more efficiently than in conventional system. The overall conversion efficiency is higher by 5% to 8%.

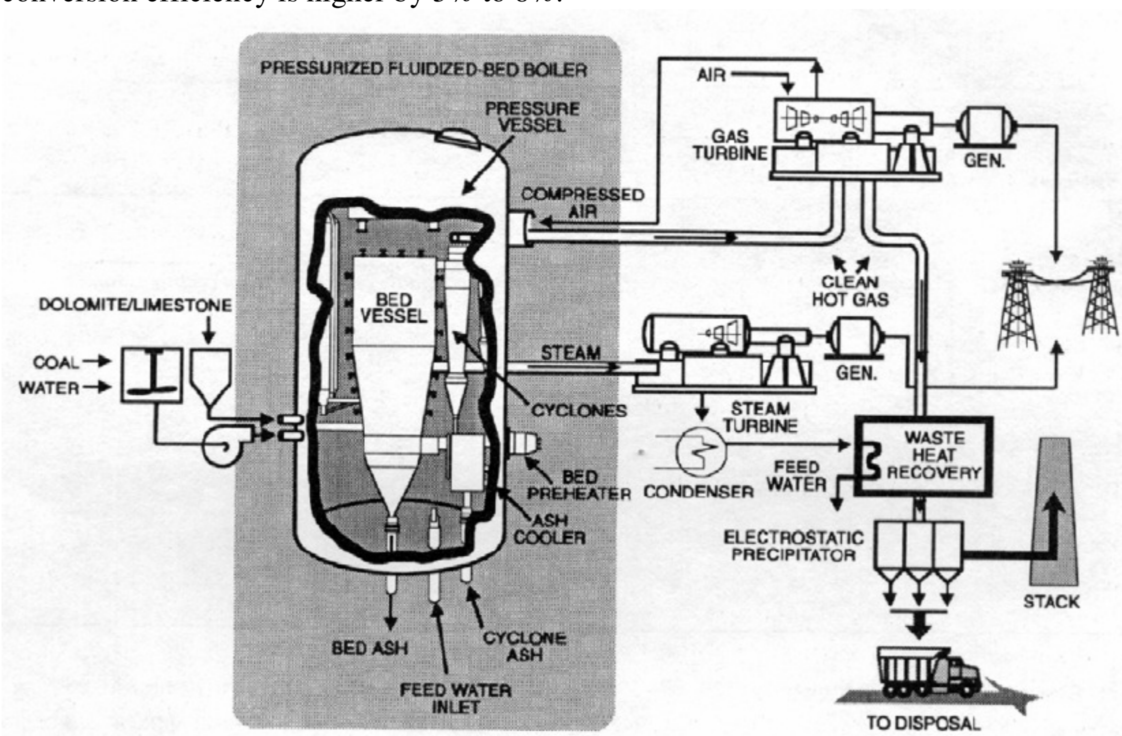

Figure 3-5: Schematic process diagram of a PFBC boiler for cogeneration (NPCI Guide books 2011)

An illustrative example of a CHP plant in Europe is the Cottbus CHP plant in eastern Germany, which started operation in 1999. The PFBC plant provides the town with district heating, as well as electricity, its maximum production being 71 MWe and 40 MWth in district heating mode. The plant uses locally mined Lausitzer brown coal (Our Brochure: PFBC Environmental Energy Technology 2011).

According to (IEA-ETSAP, Combined Heat and Power 2010) the investment costs of a gas-turbine CHP plant ranges from €650/kW_e to €1050/kW_e, with a typical cost figure of €700/kW_e. The annual operation and maintenance (O&M) costs are approximately €30/kW_e. The investment costs of a combined-cycle (CCGT) CHP plant range from €770/kW_e to €1260/kW_e and more, with a typical cost figure of €900/kW_e. The annual O&M costs are approximately €35/kW_e. The investment costs of a fluidised-bed combustion (FBC) CHP plant based on coal ranges from €2100/kW_e to €4200/kW_e and more, with a typical cost figure of €2280/kW_e and annual O&M costs of approximately €70/kW_e. The investment costs of a gas-engine CHP plant are in the range of €600–1400/kW_e, with a typical cost figure of €735/kW_e. Its annual O&M costs are about €175/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

3.3 BIOMASS-FIRED CHP

A simple, direct-fired biomass power plant can either produce electricity alone or it can operate as a combined heat and power unit, producing both electricity and heat. This latter is common in the textile, food processing, chemical and paper industries where the heat is used in the processing plant. The electricity generated is used by the plant too, with any surplus exported to the grid. Simplicity is the key feature of direct firing type of application (UNEP-DTIE 2007).

CHP based on biomass and waste, as well as on biomass co-firing in coal-fired power plants, are also rapidly growing. In Germany, for instance, the growth of biomass-based CHP amounted to 23% per year in the period 2004-2008 and state-of the- art plants are characterised by high-performance steam parameters and efficiency. The capacity of biomass CHP plants varies considerably. Biogas anaerobic digestors are usually associated to gas-fired engines for heat and power generation with electrical capacity from tens of kWe up to a few MWe. Biomass-fired CHP plants have capacities ranging from a few MWe up to 350 MWe. Small and medium-size CHP plants are usually sourced with locally available biomass. Large CHP plants and coal/biomass co-firing power plants require biomass sourcing from a wide region and/or imported wood or forestry residues. Biomass CHP plants are mature technologies while biomass integrated gasification combined cycles (BIGCC), which offer high technical and economic performance, are currently in the process of entering the market, following the industrial demonstration phase (IEA ETSAP Biomass 2010).

Continued improvements in CHP technology have made available a new generation of plants that offer advanced steam parameters and high efficiency. Circulating fluidised bed combustion (CFBC) boilers offer a further option for biomass-fired CHP. CBFC boilers are used in large CHP or power plants, with capacity of hundreds of MWe. They also are the technology of choice for large biomass- or coal-fired CHP plants (IEA ETSAP Biomass 2010).

The major process steps of a biomass-based CHP system using FBC boiler is shown in Figure 3-6. The process steps may vary from site to site depending on the nature and quality of Biomass, the type of system and the local environmental regulations (UNEP-DTIE 2007).

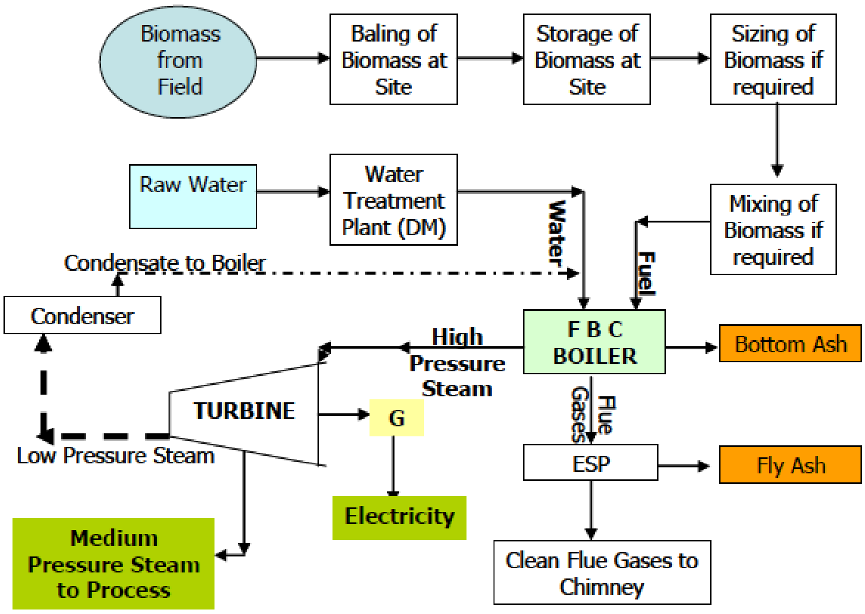

Figure 3-6: Block flow diagram of Biomass Based Cogeneration System using FBC Boiler (UNEP-DTIE 2007)

Table 3-3 presents the technical features – including electric and thermal (heat/steam) capacity – of selected biomass-fuelled CHP plants in Europe. Biomass-based CHP has successfully been applied in e.g. Germany (RWE, 2009). The optimal size of the biomass CHP plants appears to be around 20 MWe taking into account the optimal size of the biomass sourcing area (< 50km) and the number of truck loads per day (< 50). Plants with a capacity of 7 to 20 MWe are used for CHP (in Germany), whereas power plants with a capacity of 50 to 65 MWe are used solely for power generation (UK). Ten CHP plants with capacities of between 2 and 30 MWe, have electric efficiency of about 25%, thermal efficiency of 50% and overall efficiency of around 75% (IEA-ETSAP, Biomass for Heat & Power 2010).

Table 3-3: Technical features of biomass CHP plants (IEA ETSAP BIOMASS, 2010)

Country	Operator	Start Year	Technology	Electric Eff	Capacity	
				[%]	MWe	MWth
Denmark	Dong	2009	BFBC	29.9	35.0	85.0
Finland	Salmi	2002	N/A	28.3	13.6	28.0
Finland	Fortum	2010	CFBC	23.2	25.0	50.0
Germany	RWE	2004	CFBC	19.4	20.0	65.0
Germany	RWE	2005	N/A	26.6	20.0	23.0
Germany	RWE	2009	N/A	19.0	8.0	30.0
Germany	RWE	2012	N/A	N/A	7.0	30.0
Ireland	Balcas	2005	BFBC	16.0	2.4	10.0
Ireland	IBS	2004	VG	16.1	1.8	3.5
UK	Semb	2007	BFBC	29.5	30.0	10.0

Anaerobic digestion of wet manure and co-digestion of wet manure along with agricultural residues may be economically viable for the generation of heat and power using internal combustion gas engines. Thermal efficiencies of anaerobic digestion CHP units in the Netherlands have been reported to be around 55% with overall efficiency of more than 85% (IEA-ETSAP, Biomass for Heat & Power 2010).

The investment costs of biomass CHP plants with capacities of up to 50 MWe are between €2100and €4200/kWe. The annual operation and maintenance cost (O&M) of the CHP plants is approximately €70/kWe. The investment costs for anaerobic digestion with gas engines-based CHP range from €1200 to €3800/kWe, with a typical value of €3200/kWe. Investment costs of €2100/kWe or higher for digestion CHP plants refer to rather large-size plants with capacity of 1.0 - 1.5 MWe. Average O&M costs for anaerobic digestion plants with CHP are in the order of €210kWe per year. An estimate of current and projected power generation costs from biogas-fired CHP plants, including cost reductions due to larger commercialisation and technology learning is for 2008 at about €135/MWh, while the cost in 2020 is estimated at approximately €110/MWh (IEA-ETSAP, Biomass for Heat & Power 2010).

3.4 SMALL - SCALE CHP UNITS

Small-scale CHP based on gas-fired ICEs is used for capacity ranging from kWe to a few MWe and also for applications in light manufacturing, hotels, hospitals, large urban buildings and agriculture. Gas engines may use either natural gas or landfill gas (IEA-ETSAP, Combined Heat and Power 2010).

According to (IEA-ETSAP, Combined Heat and Power 2010), Natural gas-fired ICE CHP systems range from €600/kW_e to €1350/kW_e, with a typical investment cost of €800/kW_e and O&M costs of €140-210/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 €740/kW_e in 2020 and to €700/kW_e in 2030.

3.5 MICRO CHP UNITS

Stirling engines and internal combustion mchp units have been widely installed in Europe this year. For an output of 1 kW_e, efficiencies range between 13 – 25% LHV has been achieved with a heat to power 4:1 to 7:1 and an overall efficiency of 80 - 88%, comparable to a condensing boiler. Installed costs are in the range of €8000 to €11000, which is quite higher than the current installed costs of a boiler (€3500). However the prices are expected to drop to €4000 the next 4 to 5 years due to increase in the market volume

A number o f quite promising fuel cell micro-CHP technologies should start being introduced in the market in the years to come, including the CFCL (SOFC) technology which for a 1.5 kWe output, yields 35 - 60% electrical efficiency.

3.6 NUCLEAR COGENERATION

3.6.1 Background

Nuclear cogeneration is since long an established method which can provide large amounts of practically CO2 free heat. In 2010 there were 420 reactor years (RY) of experience in nuclear process heat production, and 500 RY of nuclear district heating (Khamis 2010).

For industrial heating processes nuclear heat is mainly used in the paper and pulp industry. There are examples of existing nuclear heat users in Finland, Norway, Switzerland and Russia.

District heating from nuclear power is well established in Eastern Europe. In Ukraine, the Czech Republic, Slovakia, Hungary, and Bulgaria Nuclear Power Plants (NPP) provide district heating networks of about 100 MW thermal power in each country. In Russia 11% of all NPPs are used for cogeneration purposes (IEA CHP/DH Country profile-Russia 2010). An example of district heating from nuclear power in Western Europe is the Swiss Beznau NPP, which provides heat to 20000 inhabitants. Moreover, recently a study on district heating where 1000 MW of heat was provided to Helsinki was performed, see below. In Sweden a study is currently ongoing in Oskarshamn (Svenskt Kärntekniskt Centrum 2011).

Generally, studies show that district heating can be competitive with fossil fuel powered plants, but there are other resistances to be overcome, e.g. public opinion, political (IAEA 2007).

3.6.2 Industrial process heat

All exiting process heat production with operating reactors today is performed with light water reactors. This means that only relatively low pressures and temperatures that can be provided. The case of Gösgen , Switzerland is discussed briefly below.

The NPP in Gösnau began commercial operation in 1979 (Wikipedia 2011). It is a pressurized water reactor (PWR) of gross electrical output of 1035 MW_e and thermal power of about 3000 MW_{th}. Three steam generators transfer the heat to secondary coolant loop at 65 bar and 280°C. 99% of the steam is routed to the turbine, and 1% is piped to an evaporator where it is converted into pressurized process steam which eventually is delivered to two paper and cardboard factories.

Figure 3-7: Pipeline from Gösgen NPP to Aare paper mill (Kernkraftwerk Gösgen-Däniken AG 2011).

The steam is transported through a 1.8 km long pipeline, which has a transport capacity of 70 tons of steam per hour at 200^{o}C and 12 bar equivalent to 45 MW_{th}. In 1999 the pipeline was expanded to become a district heating network as well (Fortum Power and Heat Oy. 2009) (Ibed 2010).

3.6.3 District heating

As an example of the latest technology is the study on the Loviisa NPP to provide district heating for Helsinki's 1 million inhabitants used (Bergroth 2010). It is the most recent example of a large scale NPP studied for district heating in a market economy.

Today the district heating in Helsinki is based on coal and natural gas, which produces about 5-7 million tonnes of CO_2 emissions per year. By using nuclear district heating from one single reactor it is estimated that the CO_2 emissions could be cut by 4 million tonnes. This would be done through providing 1000 MW_{th} of heat through two 75 km pipelines of 1.2 m diameter each (Tuomisto 2010). Four to seven pumping stations would be needed using about 50 MW.

The third reactor at Loviisa NPP would be constructed so that it can produce electricity only or a combination of electricity and heat in the range of 0-1000 MW. When the heat output is 1000 MW the electrical power drops only by about 160-180 MW MW_e because the heat is tapped as steam from the low-pressure turbine. To achieve this modification, large changes are required to the turbine and turbine plant. Heat would be extracted at the turbine to heat district heating water. The district heat water circuit is physically separated by two barriers from the primary circuit of the NPP. The heat is transferred to the secondary circuit (as for conventional NPPs) and then to the district heating circuit via a heat exchanger. The water is then pumped to the Helsinki area in a closed circuit where it heats buildings, afterwards the cold water returns to the Loviisa NPP.

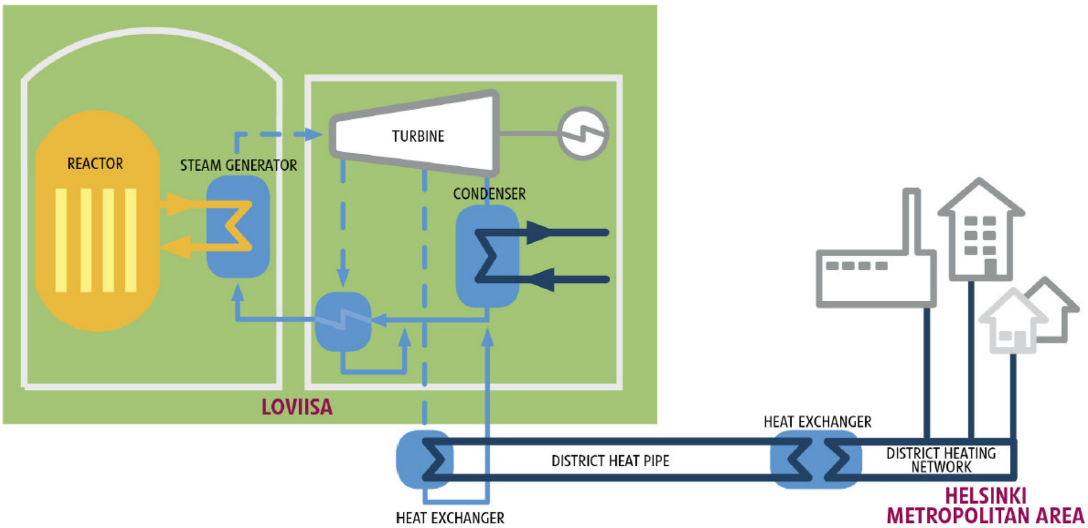

Figure 3-8: General implementation of district heat generation in a PWR plant (Fortum Power and Heat Oy. 2009) .

3.6.4 Future perspectives

As mentioned above nuclear cogeneration is already being performed at low temperatures and it is usually economically competitive as well.

Because CO_2 emissions from fossil-fired process heat generation represent a significant fraction of primary energy consumption, several countries envisage the expansion of nuclear power into this large market. Studies in Europe and in the US have shown that already the "plug-in" market for nuclear process steam (i.e. replacement of existing cogeneration plants with nuclear cogeneration) is very large and of the order of 90 GWth in Europe (Alonso-Zabalo 2005) (Bredimas 2010).

Studies on near-, mid-, and long-term applications of nuclear cogeneration usually concern smaller reactor units which are capable of operating at higher temperatures than LWRs. In most cases it is gas-cooled High Temperature Reactors (HTR) for the nearer term and Very High Temperature Reactors (VHTR) for the longer perspective of 2040 and beyond. A few major applications standing out: process steam for the (petro-)chemical industry (e.g. ethylene production), clean coal applications, hydrogen production (for (petro-)chemical industry, direct iron ore reduction with hydrogen, fertilizers) with seawater desalination as a possible low temperature tail-end application. Several countries aim at demonstration of the coupling between nuclear and process heat end users such as Japan and Korea (for hydrogen production) and the US (steam for chemical industry). Poland has recently started an R&D project on clean coal applications. In Germany, several such studies were investigated before Chernobyl made a politically motivated end to them.

With higher temperatures, a large share of industrial process heat production could be provided by nuclear power, e.g. hydrogen production, chemical industry etc. Also the smaller sizes are probably a better fit for most customers in terms of offered capacity and demand. Possibly smaller nuclear power plants can be placed closer to the end consumer too, since they are usually more intrinsically safe.

The HTR-PM in China is the most advanced high temperature reactor today. It is presently under construction at Shidaowan in Weihai city and it is planned to be ready for commercial operation in 2015. It is a twin reactor concept of a total of 210 MW electric power (Zhang 2009). This reactor can be used for hydrogen production, heavy oil thermal recover etc.

In Europe, the nuclear technology platform SNETP is also aiming at the demonstration of nuclear cogeneration (in Europe or as an international cooperation effort) so as to make the technology ready for larger scale deployment. SNETP has recently launched the Nuclear Cogeneration Industrial Initiative (NC2I). This initiative has the aim to form a public private partnership and to support a demonstration reactor. The expectation is that this will unlock the CO_2-savings potential of nuclear cogeneration in view of the SET Plan targets.

NC2I is technically supported by a number of active FP7 R&D projects, namely ARCHER (on HTR technology (S. de Groot 2010), CARBOWASTE (on waste management, http://www.carbowaste.eu/) and EUROPAIRS (specifically on nuclear cogeneration, [G], www.europairs.eu).

4 CARBON CAPTURE AND STORAGE IN POWER GENERATION

Carbon Capture and Storage (CCS) technologies can be applied to energy production wherever CO_2 is produced in large quantities. This includes, but is not limited, to power generation and promises near zero emission electricity from fossil fuels. CCS technology could enable large (90-95%) reductions of the CO_2 emissions in power generation and significant reductions in both fossil fuels transformation and energy-intensive industrial processes, e.g. cement, iron and steel production. These processes all together account for more than 65% of the global CO_2 emissions from energy use and represent large, concentrated sources of CO_2. CO_2 emissions from coal-fired power plants in 2007 accounted for about 27% of the global CO_2 emissions in the energy sector. (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010).

CCS is generally understood as consisting of three major steps: carbon dioxide capture from flue/fuel gases; CO_2 transport; and CO_2 storage. For each step there are currently several technology options, with different levels of performance and maturity, so numerous constellations for CCS can be envisaged. The portfolio of technologies currently being developed applies to both newly built power plants and also to retrofits of existing plants.

Although each step can be realised with proven technologies, these technologies need to be adapted for use in the full CCS value chain. Internationally, up to 20 pre-commercial implementation projects are aiming to demonstrate various combinations of CCS technologies, with more projects in the construction and development phase.

4.1 CARBON CAPTURE, TRANSPORT AND STORAGE TECHNOLOGIES

CCS is divided into CO2 capture at the industrial source, transport to a place of storage and permanent storage.

Currently there are three main methods for capturing CO2 in power plants (see Figure 4-1): Post-combustion, pre-combustion and oxy-fuel combustion capture. Among all capture methods, CO2 scrubbing techniques are the most mature. MEA-based scrubbing has been utilised for more than 60 years for natural gas purification and food-grade CO2 production. In particular, Rectisol and Selexol processes have been commercially used since the 1990s for CO2 capture in the refining, chemical and fertilizer industries and are today extensively used in gasification plants to purify synthesis gas for downstream chemical applications. Current units, using these techniques, are able to remove thousands of tonnes of CO2 per day. However, they have not yet been demonstrated on the large scale necessary for 90% CO2 capture from a typical 500MW coal-fired power plant where 10 000 – 15 000tons of CO2 would be removed per day.

The net efficiency of commercial SCPC plants equipped with oxy-fuel capture or post combustion capture is estimated at about 35% LHV (IEA GHG). The efficiency of both oxy-fuel and pre-combustion capture depends significantly on the energy needed for oxygen production. A typical 250 MW IGCC plant needs some 2000 tonnes O_2 per day and currently, large-scale O_2 production (3000 t/day) based on cryogenic separation requires 0.28-0.30 kWh/Nm^3 of low-pressure oxygen (about 0.8 GJ/tO_2) (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). High-pressure processes, pressure swing adsorption, ceramic oxide ion transport membranes might reduce energy and capital cost for O2 production by 30%, and increase the efficiency of IGCC plants by 1 to 2 percentage points (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). These technologies however require further research effort.

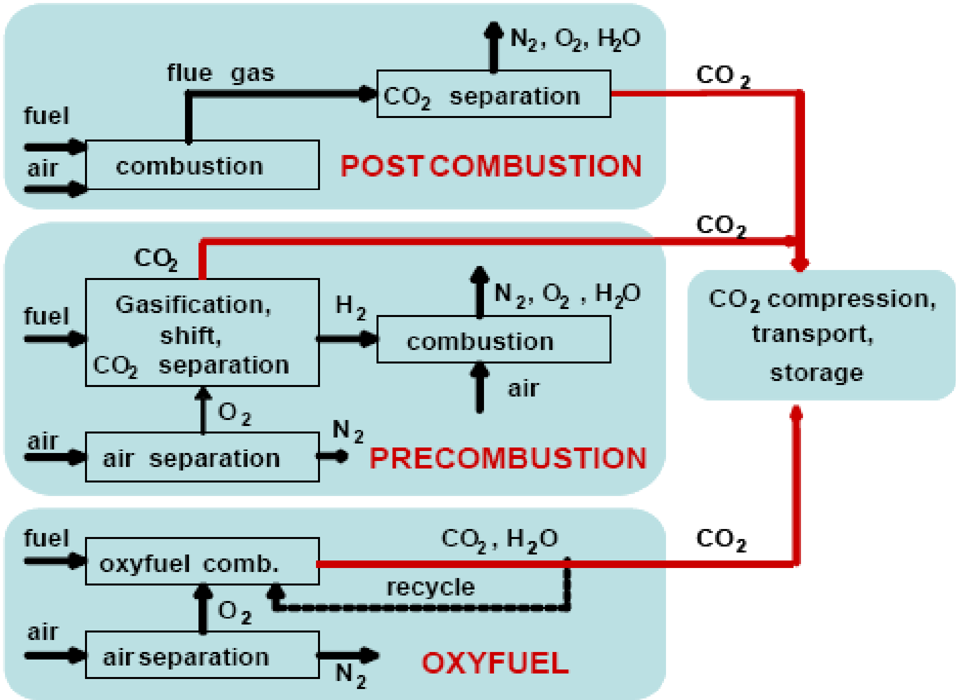

Figure 4-1: CCS technologies for power generation (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010)

Other capture technologies such as anti-sublimation, enzymes and algae for post-combustion and chemical looping and high pressure oxy-reactor are still at an early stage of development, with commercial deployment generally considered to be unlikely before 2025 .

Transport technology of Carbon dioxide is mature, since CO_2 is already transported for commercial purposes by road tanker, by ship and by pipeline. Although each of these methods is practical, there is a need for scaling up in order to accommodate for the future quantities of CO_2 to be transported from source to storage site that will be considerable. Hence, it is most likely that local and regional infrastructures of pipelines will ultimately need to be developed. The technologies involved in pipeline transportation vary little from those used extensively for transporting gas or oil. Indeed, in some cases, it may be possible to re-use existing but redundant pipeline infrastructures. Large networks of CO_2 pipelines, mainly associated to Enhanced Oil Recovery (EOR) operations, have been in use since the early 1980s and are operated commercially with proven safety and reliability records. Most of them lie in the US where more than 4 000 km of pipelines already exist, with the Permian Basin containing between half and two thirds of the active CO_2 floods in the world [4, 5]. Recently networks have started to operate in Europe, with the biggest infrastructures in the North Sea, e.g. 160km pipeline for Snøhvit LNG project, and in the Netherlands, about 80km pipeline from Rotterdam to Amsterdam to transport CO_2 to greenhouses.

Various technical options for the long-term storage of CO_2 are being researched. Geological storage is by far the cheapest and most promising option and industrial geological CO_2 storage projects have already been initiated in Europe and worldwide. Different types of geological formations are being used and investigated, especially oil and gas reservoirs, deep saline aquifer formations and un-mineable coal beds. There is an estimated global storage potential of 10 000 Gt CO_2, with 117Gt in Europe. Compressed

CO_2 is already injected into porous rock formations by the oil and gas industry, e.g. for EOR, and is proven at a commercial scale. Due to its possible environmental implications, the current option of CO_2 storage deep in the oceans is no longer considered an option. Mineral carbonation is an alternative for storing CO_2 in materials. However, due to the large amounts of energy and mined minerals needed, it is not likely to be cost effective.

Retrofitting an existing power plant with CCS technology is currently a quite costly option that can result to an overwhelming efficiency penalty. Efficiency losses up to 14% and investment cost in the order of more than €700/kW have been reported (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). As a consequence, retrofit makes sense only for recent coal and gas-fired power plants with high net electric efficiency (> 40% and 55%, respectively). However, these types of plants cover only a 10% of the existing electricity capacity. Oxy-fuel combustion which is the most suitable retrofitting option for a SCPC power plant, would require additional energy input for O_2 production (ASU) and CO_2 pressurization (150 bar), and the use of up to 35% of the electricity produced in with the plant without CSS, with a 75% net reduction of CO_2 emissions.

Despite the fact that retrofitting technologies are not yet commercially viable, fossil fuel-based power plants currently under commissioning are designed to enable CCS retrofit (capture-ready plants) as soon as the technology will become commercial and marketable, in order to avoid the lock-in of CO_2 emissions. Some governments (e.g. UK) already require CCS on a proportion of new capacity and envisage retrofitting for the remainder (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Capture-ready plants involve space allocation for capture facilities (e.g. shift reactor, large ASU) to be installed later on as well as identification of CO_2 transportation facilities and storage sites. Available studies (IEA-GHG, CO2 Capture Ready Plants, Report Number 2007/4 2007) suggest capture ready plants may offer a significant reduction of retrofitting cost and time, with relatively inexpensive pre-investment.

Presently the two major technologies for electricity production from fossil fuels in the EU are Pulverised Coal Combustion and Natural Gas Combined Cycle. Both systems could be equipped with CCS technology, both in new plants and as retrofit applications. Zero-emission fossil fuel power plants (or ZEP plants) will capture at least 85% of the CO_2 formed during the power generation process. The captured CO_2 will be transported to suitable underground locations where it will be stored permanently and safely. Currently, all elements of the technology of ZEP plants have been developed and utilised by other industrial sectors, but on much smaller scales than those needed for electricity generation and to-date, no integrated commercial CO_2 capture and storage (CCS) project with power generation is in operation. Seven commercial projects with CO_2 capture, transport and storage are currently running. The Canadian Weyburn-Midale project, in the frame of an EOR plan, demonstrates CO_2 storage using CO_2 from a gasification plant producing syn-fuel. In Norway, CO_2 removed from natural gas up-grading, has been injected since 1996 and 2008, into the offshore Sleipner and Snøhvit fields respectively, and in Algeria in the In Salah field, since 2004. Two large projects are currently on-going in Australia (Otway basin) and in the Netherlands (K12B) and several are in preparation (among the largest, the Gorgon project and the Monash project in Australia). Altogether, about 3Mt of CO_2 are stored annually. In 2007, about 95 CO_2-EOR projects worldwide, mainly in the USA, injected about 40Mt of CO_2 into oil reservoirs. The world's first coal fired oxy-fuel CCS plant with power generation is Vattenfall's Schwarze Pumpe 30 MW pilot plant, inaugurated in September 2008 in Spremburg, Germany. The captured CO_2 however, is not yet stored. Several other projects for demonstration of CO_2 capture from power plants, based on a variety of storage techniques, are currently planned in the EU-27, and between 2010 and 2017, 48 projects could become operative.

4.1.1 POST COMBUSTION CAPTURE

Post-combustion capture involves removing the dilute CO_2 from flue gases after combustion of the fuel. Flue gases contain 4% to 8% of CO2 by volume in gas-fired plants and 12% to 15% of CO2 in coal-fired plants (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Currently, the favoured technique for post-combustion capture is chemical solvent scrubbing (see Figure 4-2). The flue gases are washed with a solvent that separates the CO_2 from nitrogen. In a de-absorber, the solvent is reheated and the CO_2 driven off. CO_2 is then cooled and compressed, ready to be piped away. Chemical solvents create strong chemical bonds with CO2 and require significant thermal energy for CO2 release. Unlike physical adsorption, the energy need for chemical absorption (i.e. 0.3 kWh/kgCO2) is slightly sensitive to CO2 concentration (10% energy reduction if the CO2 concentration increases from 3% to 14% in volume) (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010), making chemical absorption favourable option for flue gases with low CO2 concentrations (e.g. NGCC flue gas).

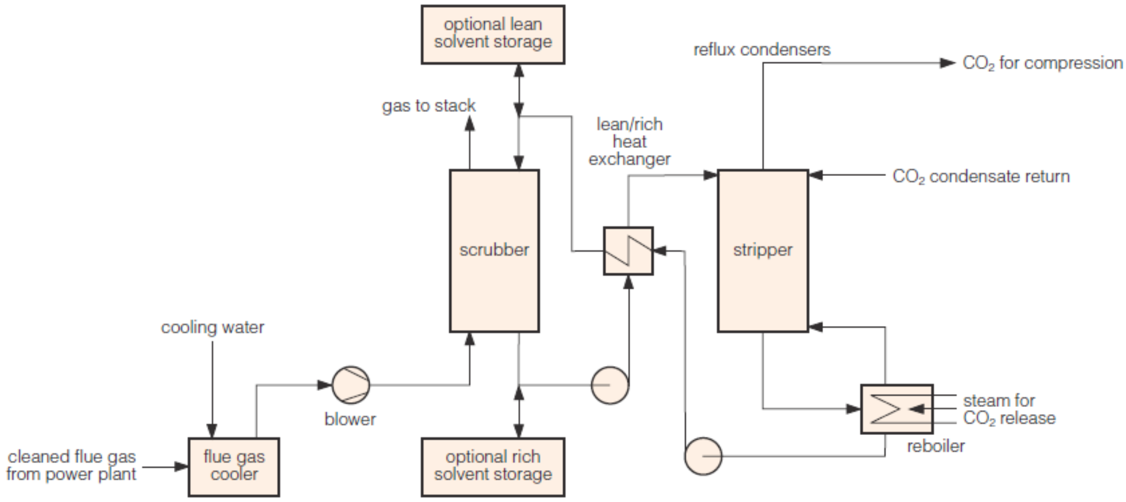

Figure 4-2: Schematic diagram of a post-combustion capture process added at a pulverised coal power plant (Chalmers 2010)

The technique can be applied to both pulverised coal and natural gas sub- and super-critical power plants, and can be retrofitted to existing plants without significant modifications to existing infrastructure. Retrofitting would therefore appear to be the most economical technology. The most widely used solvent for CO_2 scrubbing is monoethanolamine (MEA). Apart from the solvent degradation by impurities such as SO_x, NO_2 and O_2, the main issue with MEA is the large amount of energy required for its regeneration. Alternative solvents which require lower energy for regeneration and at the same time present better absorption-desorption and corrosive properties are being developed, with currently amino salts and chilled ammonia the most promising. Solid sorbents at high temperature, such as calcium-lithium based oxides, and sodium and potassium oxides are also being investigated.

The CCS efficiency penalty currently ranges from 8 to 12 percentage points and is expected to decline to below 8 points by 2020 (IEA-ETSAP, Technology Brief E14 on

CO2 Capture & Storage 2010). In spite of the higher CO_2 concentration in coal-fired power plants flue gases, the CO_2 emissions per kWh is twice as high (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). As a result, the efficiency penalty in coal-fired power plants tends to be higher than in NGCC plants.
Post combustion capture technology phases certain challenges. One of them is to find ways to reduce the energy needed for solvent regeneration, CO_2 release and compression. Degradation of the solvent can also be tackled by reduced concentrations of NO_X, SO_2 and O_2 in the flue gas. Alternative solvents under investigation include sterically hindered amines, potassium carbonates, and ionic acids with less regeneration energy, less degradation risks (higher sulphur tolerance) and corrosion. Amino-acid salts show potential for reducing capture costs by 50% in SCPC plants and by 40% in NGCC plants (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Separation membranes (polymeric gel, ceramic, contactors) are currently being developed for both pre- and post-combustion capture applications, and combinations of membranes, solvents and solid adsorption processes (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010).

4.1.2 PRE COMBUSTION CAPTURE

Pre-combustion capture involves removal of CO_2 prior to combustion of hydrogen in a gas turbine, in an integrated gasification combined cycle (IGCC) plant (see Figure 4-3), or prior to combustion in a natural gas combined cycle (NGCC).
In the IGCC solid, liquid or gaseous fuel is first converted to a mixture of hydrogen and carbon monoxide using one of a number of proprietary gasification technologies. There with addition of oxygen (O_2) and steam syn-gas (i.e. a mix of mainly H_2 and CO, with CO_2, CH_4 and impurities) is produced. In a so called 'shift reactor', the carbon monoxide is oxidised to CO_2, and produce a high-pressure (up to 70 bar) mix of H_2 and CO_2, with high CO_2 concentration (up to 40%). CO_2 is subsequently separated from the hydrogen.

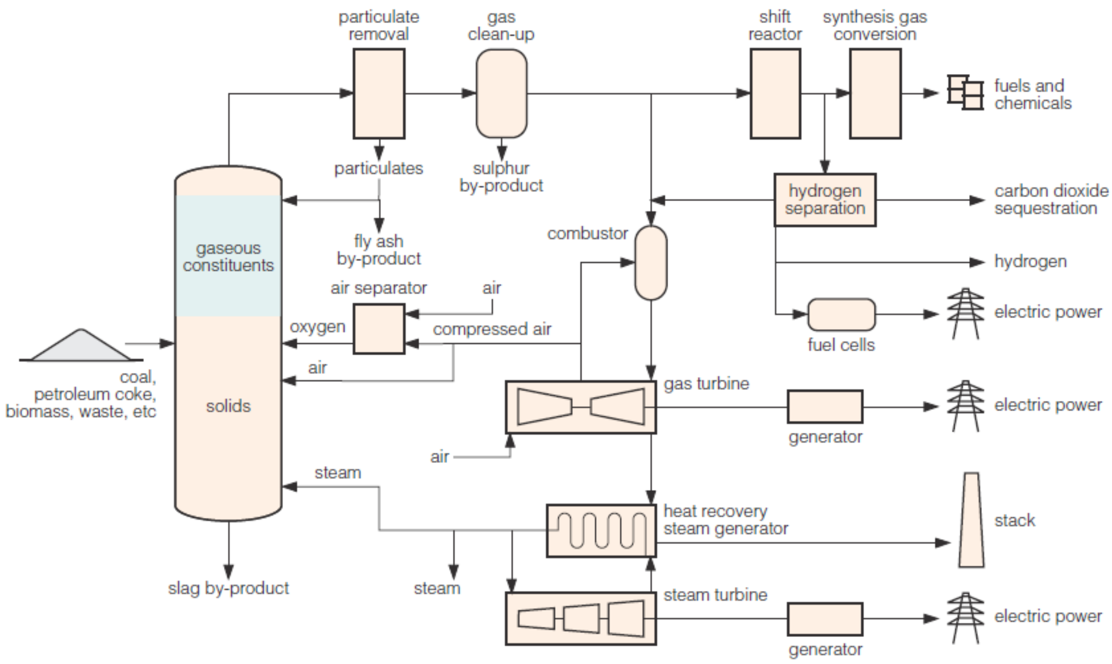

Figure 4-3: Schematic diagram of an IGCC process with pre-combustion capture (Chalmers 2010)

The hydrogen is diluted with nitrogen and burned for electricity generation in a combined-cycle gas turbine. The partial pressure of the CO_2 in the gas to be treated is about 1000 times higher than for post-combustion capture and physical solvents for the separation are preferred. In physical adsorption, the CO_2 is captured by weak bonds created at high pressure and released at low pressure: the higher the CO_2 concentration, the lower the energy needed for pressurization. Physical absorption is therefore more efficient at high CO_2 concentration (>15%) (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Scrubbing of CO_2 with physical solvents is a well established process in the chemical industry, e.g. ammonia production and synthesis gas treatment. Cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process) and propylene carbonate (Fluor process) are the most commonly used solvents. The efficiency of pre-combusiton capture depends significantly on the energy need to produce the oxygen in the air separation unit (ASU).

Other possibilities for CO_2 separation include: adsorption on solid materials, such as zeolites or activated carbon; pressure-swing adsorption, where the adsorbent is regenerated by reducing the pressure; and temperature-swing adsorption, where the adsorbent is regenerated by increase of temperature. Separation can also be achieved with selective membranes. However at the present time membranes cannot achieve a high degree of separation and improvement is needed for their cost-effective use on a large-scale. If CCS is added to the process, the syn-gas must be sent to the shift reactor and deep syn-gas cleaning is needed to reduce pollutants emissions and protect the H2-fired turbine (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Another challenge is the modification of gas burner and turbine technologies to achieve higher efficiencies in the electricity production from hydrogen combustion.

4.1.3 OXY-FUEL COMBUSTION

In ***oxy-fuel combustion***, fuel is burned in oxygen-rich (high purity) O_2 atmosphere. The O_2 is provided by an air separation unit, often cryogenic but also membrane-based, where the air is divided prior to combustion, into nitrogen and oxygen. In practice for temperature control, oxygen is diluted by recycling some of the CO_2 from the flue gas (see Figure 4-4. The main advantage of oxy-fuel combustion is the high concentration of CO_2 in the resulting flue gas (70% to 85% or more), so that only relatively simple purification of CO_2 is needed before storage.

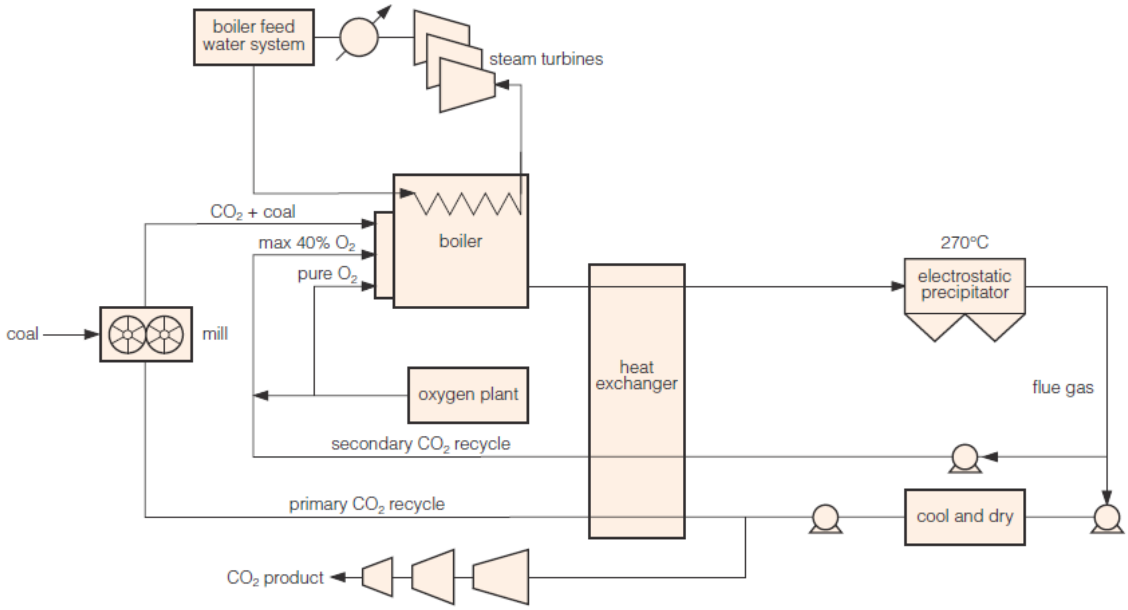

Figure 4-4: Schematic diagram of an oxy-fuel process at a pulverised coal power plant (Chalmers 2010)

This process is currently being tested in the EU at pilot scale and has been demonstrated in steel manufacturing industry at plant scale of up to 250 MW. A few pilot power plants with oxy-fuel combustion (30-40 MW capacity) are in operation (Germany) or in advanced construction (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). If low-cost O_2 is available the process has the potential to be cheaper than the pre- and post-combustion capture concepts, with high efficiency levels, and large flexibility because of the possibility to retrofit in existing plants. The main disadvantage is the large quantity of oxygen required, which is expensive both in terms of capital costs and energy consumption.

The oxy-fuel combustion could also apply to IGCC and NGCC plants with CCS. Research efforts focus on energy saving in O2 separation, on materials for high temperature combustion and on applications to industrial cement kilns.

4.2 TRANSPORT

CO_2 transport can be realised through by pipelines, ships and road tankers. Transportation via pipeline is cost-effective for large quantities (> 1-5 Mt/y) and distances (> 100-500 km). Around 6200 km of pipelines (0.6-0.8m diameter) are currently handling about 50 Mt of dehydrated CO_2 per year globally to distances up to over 800 km in the USv (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010).

CO_2 is transported in a supercritical state, with a density ten-time higher than that of natural gas. As a result, CO_2 piping requires less energy than natural gas: the typical distance between CO_2 pumping stations is about 200 km in comparison with 120-160 km for natural gas (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). The energy need for CO_2 transportation and compression depends on distance and pressure, and typically is 0.2 - 0.5 GJ of electricity/tCO_2 (per 100-200 km) (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Low rates of CO_2 leakage have been reported and no major safety concern has been identified. The only risk is the higher CO_2 density than that of air. As a consequence, possible leakages can result in CO_2 accumulation and concentration at ground level. Leakage risk can increase in the presence of H_2S and SO_2 impurities.

Pipelines deployment could be in the order of 10,000-12,000 km in the next ten years (to transport 300 MtCO_2 from 100 CCS projects), 70,000-120,000 km by 2030, and 200,000-360,000 km by 2050, with investment in the order of €0.4-0.7 trillion (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). CO_2 can also be transported by ship either in semi-refrigerated tanks (-50°C, 7 bars) or in compressed natural gas (CNG) carriers. This is a viable option only for small CCS projects.

4.3 STORAGE

Various geological formations such as deep saline formations, depleted oil and gas reservoirs (with or without enhanced oil recovery), or deep un-mineable coal seams can be use for CO_2 storage. Major CO2 storage mechanisms include (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010):

- Physical trapping, an immediate immobilization of CO2 in a gaseous or supercritical phase in the geological formations (static gas trapping in porous structures);
- Chemical trapping, a dissolution or ionic trapping in fluids, e.g. water/hydrocarbons. Once dissolved, the CO2 can react with minerals (mineralization or adsorption on mineral surface). Dissolution and mineralization may occur over geological time;
- Hydrodynamic trapping**,** a slow upward migration of CO2 to impermeable intermediate layers over millions of years.

CO_2 storage is intended to last for thousands of years with no significant leakage. Monitoring data from ongoing storage demonstration projects show no CO_2 leakage and

CO_2 behaviour according to expectations (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). However, more experience is needed to either understand the underground behaviour of the injected CO_2 and to characterise the geological formations for large-scale, safe and long-term storage. Estimates of worldwide storage capacity vary considerably with the global potential ranging between 2000 and 20,000 GtCO2. It is therefore clear that further research and studies are needed in this field. Nevertheless, the lower bound of the global storage capacity would be enough to store global emissions for several decades (according to (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010), current and projected global annual CO_2 emissions are 25 and 50 GtCO2/y, respectively). The global storage potential could be well above this level. Significant uncertainties exist for the capacity of deep saline formations (the largest storage resource). Uncertainties also exist as far as the environmental impact, cost and regulatory framework are concerned.

An alternative use of the captured CO_2 is its storage in depleted Oil & Gas fields with enhanced oil or gas recovery (EOR, EGR) – The CO2 is the second most used fluid for EOR, following steam. The fluid choice depends on the hydrocarbon density. Estimates suggest CO2- based EOR can increase the ultimate oil production by an average 10%. Using CO2 for EOR can produce an additional 0.1-0.5 ton of oil per ton of CO2 injected (an average 2.5-3.0 tCO2/t oil produced).

Estimates of storage potential range from a few GtCO2, to several hundreds GtCO2 (Europe, North America, China, Qatar, Russia Venezuela). In some 400 sites worldwide (with total storage capacity of 0.5Gt/yr), CO2 sources and depleted oil fields are within 100 km distance (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Preliminary estimates suggest that some 30 Mt CO2 per year could be used for EOR over a period of 15 to 25 years and that CO2-based EOR could have a potential of 5-6 million bbl per day by 2030. Increasing oil prices and the availability of CO2 transportation infrastructure are key incentives for CO2-based EOR. The cost of EOR-based CO_2 storage is currently estimated at €14-21/tCO_2 and it is largely offset by the oil production revenue. Depleted oil and gas fields offer low-cost opportunities for CO_2 storage as facilities and wells are often in place, and the geological characterization of the site is already available. Worldwide storage capacity estimates ranges between 675 Gt and 1200 Gt (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). Prior to storing the gas, an accurate assessments of well integrity and chemical reaction of CO_2 with in-situ minerals and fluids are needed.

CO_2 can also be injected to depleted gas fields and therefore increase gas recovery and to reduce subsidence. The CO_2 is denser than natural gas and flows downwards displacing the natural gas. The CO_2- EGR is less profitable than CO_2-EOR. An initial screening of gas fields suggests a worldwide storage potential of 800 Gt CO_2 in depleted gas fields at €86/tCO_2 (about 6 times the EOR cost). At €36/tCO_2, the total CO_2 storage potential in depleted gas fields declines to 100 Gt (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010).

The K12B injection offshore in the Netherlands is the only ongoing CO_2-EGR project of a significant size where the CO_2 (30,000 m3CO_2/d) contained in a natural gas field is separated and reinjected at 3500-4000 m - the deepest CO_2 injection to date.

4.4 COST OF CCS

In general, apart from a few low-cost opportunities in some industrial processes (e.g. ammonia production) and in natural gas processing, CCS is rather an expensive technology, and applications in industrial processes are more expensive than applications in power generation, i.e. €25-40/tCO2 for coal-fired power and €38-52/tCO2 for gas-fired power. Approximately, the upper and lower bound of each cost range suggest current and projected costs, respectively, including CO2 capture, transportation and storage. (IEA, 2008a; IEA 2009a; IEA 2010) are shown in Figure 4-5 .

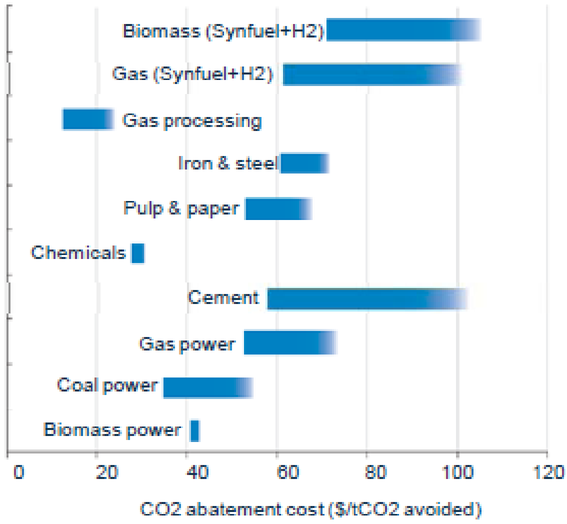

Figure 4-5: Cost of CCS in different industries (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010)

4.4.1 CCS cost in Power Generation

The cost of CCS applications in power generation follows the technology spit:

- capture cost (including additional capacity and fuel to compensate for the loss of efficiency, CO2 capture and compression equipment),
- transportation cost, and
- storage costs.

The capture cost is the dominant CCS cost (about 70%) while transport (taking into account an average distance of 200 km) and storage (i.e. injection, storage and monitoring in deep saline formations) account for approximately 15% each. It is expected that the capture cost will decline over time due to technology learning while transportation and storage might increase because of transportation distance, cost of pipelines, regulatory- and safety-related costs (legal rights, liability, insurance, monitoring) (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010).

Assuming a reasonable rate of technology learning, the overall CCS cost is expected to fall down from the current range of €36-64/tCO2 to some €35/tCO_2 by 2030 (IEA-ETSAP, Technology Brief E14 on CO2 Capture & Storage 2010). The cost reduction could be more difficult for NGCC plants where CO_2 concentration is lower: in principle, the higher the CO2 concentration in the flue gas the lower the specific cost of the capture. However, the cost of the capture per unit of electricity will not be so different for coal- and gas-fired power because of the more than double emissions of CO2 per unit of electricity in coal plants. The CCS costs translate into an additional cost of electricity generation.

Comparing power plants with and without CCS suggests a current additional costs for CCS between €21/MWh and €29/MWh for coal-fired plants (assuming €40-55/tCO2 captured, €43-54/tCO2 avoided), and €21/kWh for gas plants (€36-64/tCO2 captured,

€43- 79tCO2 avoided). These costs are projected to drop to €21/MWh (€36-46/tCO2 avoided) for coal and € 14/MWh (€39-64/tCO2 avoided) for gas by 2030. About 50% of the cost increase for coal plants is due to CO2 transportation and storage and depends on local circumstances. Transportation & storage cost of €14/tCO2 in 2010 and €11/tCO2 in 2030. These estimates do not account for possible EOR, which could offset the CCS additional costs and provide a net profit from CO2 storage. However, the global EOR-based storage potential is limited.

The investment cost for different types of coal power plants with and without CCS is shown in Figure 4-6. The additional investment cost for CCS ranges from €400/kW to € 1200/kW, an increase of between 50% and 100% as compared to the plant with no CCS. Because of the high cost and loss of efficiency (8-12 percentage points in coal power plants), the CCS in power plants makes sense economically only for large, highly-efficient plants.

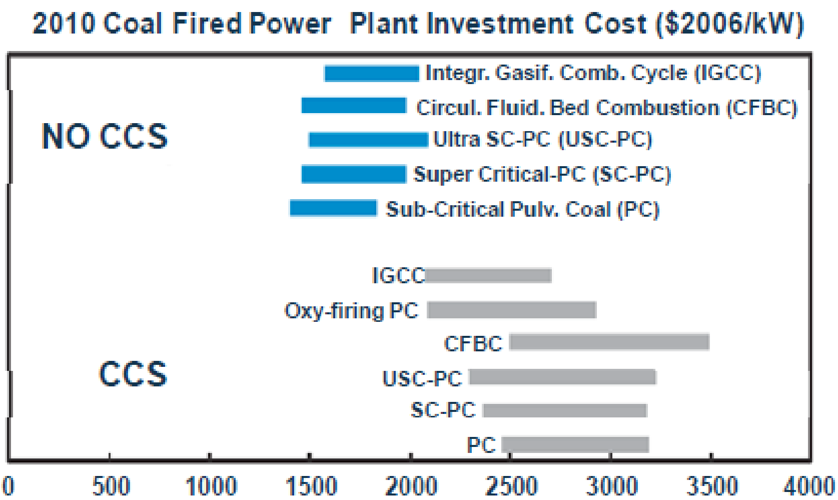

Figure 4-6: Power plants investment costs with/out CCS (IEA-GHG 2008)

The incremental investment cost for CCS demonstration in existing coal power plants is currently estimated between €0.4 and €0.7 billion, 50% of which for the CCS equipment. The IEA, in its most ambitious CO2 mitigation scenarios, (IEA, 2008b and 2010b) estimates that some 3400 plants with CCS will be needed by 2050 to meet the missions reduction targets. The associated incremental CCS cost is likely to be in the order of 40% of the cost without CCS and would be between €1.8 and €2.1 trillion, of which €0.9tr for capture, €0.4-0.7 tr for transport and €0.4 tr for storage).

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Abstract

This report provides an overview of the current state of the art of the technologies used in EU for power and heat generation as well as combined heat and power generation (cogeneration or CHP). The technologies are categorised per fuel but also in terms of technology selection. The fuels considered are the ones reported in the Strategic European Energy Review report on Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport (SEC(2008) 2872).

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