

EXECUTIVE SUMMARY

Background

One of the ways of substantially reducing the emissions of CO₂ from fossil fired power generation is to maximise the efficiency of new plants being installed to meet future demand growth and for replacing inefficient capacity. This series of case studies was conducted to show what is achieved now in modern plants in different parts of the world. It arose from a request to the IEA in the Plan of Action regarding climate change that emerged from the G8 Summit communiqué in July 2005 to:

“... carry out a global study of recently constructed plants, building on the work of its Clean Coal Centre, to assess which are the most cost effective and have the highest efficiencies and lowest emissions, and to disseminate this information widely ...”.

Recent coal-fired power plants of high efficiency use pulverised coal combustion (PCC) with supercritical (very high pressure and temperature) steam turbine cycles, and so most of the case studies are drawn from these. They were selected from different geographical areas, because local factors influence attainable efficiency. A review of current and future applications of coal-fuelled integrated gasification combined cycle plants (IGCC) is also included. Although these are small in number and not recently constructed (one is being constructed currently) so that there are greater cost and other uncertainties, the technology could form the foundation of many future power stations, with its very low conventional emissions and potential advantages for CO₂ capture. It should be noted that there is more uncertainty in IGCC cost and performance projections as the commercial ordering of coal-fuelled IGCC as a complete system for power generation by utilities has yet to occur. There is also a case study of a natural gas-fired combined cycle plant, included to facilitate comparisons.

Work method

Data gathering by questionnaire was followed up with plant visits by IEA CCC personnel. Information was also obtained from published sources. Some of the data, especially on costs, could not be supplied by all owners because of confidentiality considerations. Data gathering was carried out during 2006 and followed by analysis and report preparation. The final report does not include all the detailed information. The intention has been to identify and summarise important messages that emerge.

Case study plants

A list of the coal-fired plants, with boiler and turbine suppliers, some key features and the bases of the selections, is given in Table S1. The two plants

in Europe are a cold sea water cooled plant fired on internationally-traded, bituminous coals (Nordjyllandsværket 3, Denmark) and an inland, lignite-fired unit in Germany (Niederaussem K). The case study plant in North America is the first modern supercritical unit and fires sub-bituminous coal. In Asia, three plants are included. In Japan, Isogo New Unit 1 has the highest steam conditions in the world among currently operating sliding pressure units and very low emissions. The first two units at Younghung Thermal Power Plant in the Republic of Korea illustrate the progression toward higher steam conditions ongoing in that country, and the first two units at Wangqu in China mark a development in firing low volatile coals in supercritical units. The subcritical plants in India, at Suratgarh, and South Africa, at Majuba, cover high ash coal burning in difficult locations, with Majuba illustrating the use of dry cooling. Experience will be relevant to future supercritical plants in these countries. The study findings are summarised below.

Nordjylland 3, Denmark

The 400 MWe Unit 3 at Nordjylland power station, owned by Vattenfall, is a sea water cooled ultra-supercritical unit fired on internationally-traded, bituminous coals. Opened in 1998, the plant is situated near the town of Aalborg, which it also supplies with heat. In power-only mode, net efficiency is 47%, on a fuel LHV basis* (44.9% on an HHV basis), so Nordjylland 3 is the most efficient coal-fired unit in the world. The high efficiency comes from use of a double reheat steam cycle at very high conditions (29 MPa/582°C/580°C/580°C) plus a low condenser pressure from the availability of cold sea water for cooling. The steam conditions took full advantage of newly available materials when the plant was designed but also necessitated the use of flue gas re-circulation and advanced water treatment as well as care in start-up to ensure integrity of boiler components.

Airborne emissions are very low. For NO_x control, the tangentially fired boiler has low-NO_x burners, overburner air and over-fire air as well as a selective catalytic reduction (SCR) unit. For dust removal there are electrostatic precipitators (ESPs,) and a limestone-gypsum flue gas desulphurisation (FGD) system achieves extremely low SO₂ residual levels. Virtually all solid by-products are utilised and calcium chloride liquor from the FGD waste stream will shortly be sold for road de-icing.

No economic information was available from the plant operators. According to DONG Energy (who now own ELSAM, the previous owners of the plant), the contracting strategy was owner design with multi-contract procurement. Information on the current cost of an 800 MWe ultra-supercritical plant from Siemens indicates that it would be around 1500 USD/kWso in 2006, excluding owner's costs or interest during construction.

**The calculation of fuel LHV used as the basis of the LHV efficiency throughout this publication includes subtraction of the latent heat of the water vapour formed from evaporation of the moisture originally present in the coal as well as that of the water vapour formed from combustion of the coal hydrogen.*

Table S1 • Main features of the eight coal-fired case study plants and bases for selection for study

Plant	Siting	Coal	MWe net	Boiler geometry	Main suppliers: boiler; turbine	Ultra-super-, Super- or sub-crit	Steam conditions MPa/°C/°C(°C)	Why selected
Europe – Denmark: Nordjyllandsværket 3	coastal	international	384	tower	FLS miljo/BWE, Aalborg Industries, Volund Energy Systems; GEC Alsthom (now Alstom)	USC	29/582/580/580	Most efficient coal plant; double-reheat; very low emissions
Europe – Germany: Niederaussem K	inland	lignite	965	tower	EVT (today Alstom), Babcock and Steinmüller (today HPE); Siemens	USC	27/580/600	Lignite; top efficiency lignite plant; lignite drier demonstration
North America – Canada: Genesee 3	inland	sub-bituminous	450	2-pass	Babcock-Hitachi	S/C	25/570/570	Sub-bituminous coal; first sliding pressure S/C North America
Asia – Japan: Isogo New Unit 1	coastal	international	568	tower	IHI; Fuji Electric (Siemens)	USC	25/600/610	Very high steam parameters; very low emissions; activated coke regenerable FGD
Asia – Korea: Younghung	coastal	international	2x774	tower	Doosan Heavy Industries & Construction Co.	S/C	25/566/566	Most recent and largest coal-fired units in Korea
Asia – China: Wangqu 1, 2	inland	Chinese lean	2x600	2-pass	Doosan Babcock; Hitachi	S/C	24/566/566	Location; wall-firing of low-volatile coal with low NOx
Asia – India: Suratgarh 1-5	inland	~30% ash	5x227	2-pass	BHEL	Drum sub-crit	15/540/540	Location; high ash coal; drum boiler
Africa – South Africa: Majuba 1-6	inland	~30% ash	3x612 (dry) 3x669 (wet)	tower	Steinmüller; Alstom	once-through sub-crit	17/540/540	Location; dry versus wet cooling; high ash coal, once-through sub-critical boiler

USC: ultra-supercritical (steam temperatures of 580°C and above)
S/C: supercritical

This impressive unit was a result of initiatives by Danish utilities to move to much higher efficiency plants of high flexibility by working with major suppliers on designs that are practical and economic at high steam conditions. Danish engineers are continuing to look at innovative means to reach still better performance in future plants.

Niederaussem K, Germany

Niederaussem K, owned by RWE Power, is a 1000 MWe ultra-supercritical lignite-fired unit near Cologne. Net efficiency is 43.2%, on a fuel LHV basis (37% on an HHV basis). The unit is the most efficient lignite-fired plant in the world. Niederaussem K opened in 2002, and there are two further units based on the technology under construction at a neighbouring RWE power station site at Neurath.

In addition to the advanced steam conditions (27.5 MPa/580°C/600°C), there are other features that have been used for very high efficiency. Among these are a complex water circuit to exploit a unique heat recovery system downstream of the main economiser and a flue gas cooler for final heat recovery. The condenser pressure has also been made low by incorporating an unusually tall cooling tower. Although there were a few early difficulties with materials in parts of the boiler, these were solved by use of newer alloys.

NO_x emissions from the boiler are low from the use of wall-mounted lignite-specific low-NO_x burners and other fuel and air staging arrangements, so there is no downstream flue gas NO_x control equipment. Electrostatic precipitators collect fly ash, and a wet FGD unit desulphurises the emerging flue gas.

The investment cost was around 1175 USD/kW_{so} in 2002, including interest during construction and owner's costs, and construction took 48 months.

The efficiency is very good for a plant firing 50-60% moisture content lignite fuel. A demonstration plant for pre-drying part of the lignite fuel feed using low grade heat is being installed to enable even higher efficiencies. The new units at Neurath will have slightly higher steam conditions and a simpler cycle, but include many of the features of Niederaussem K.

Genesee 3, Canada

Genesee 3, opened in March 2005, is the first sliding pressure coal-fired supercritical unit to be commissioned in North America. The 450 MWe unit, located 75 km from Edmonton, is jointly owned by EPCOR and TransAlta Energy Corporation. It operates on a sub-bituminous Albertan coal. Steam parameters (25 MPa/570°C/568°C) were chosen to maximise efficiency while minimising risk and net efficiency is over 41% on an LHV basis (40% on an HHV basis). The overall configuration consists of a two-pass supercritical boiler, a single reheat supercritical cycle with eight stages of feedwater heating, a spray-dry flue gas desulphurisation unit, and a bag filtration system.

Genesee 3 had to be suitable for flexible operation in a market-oriented environment without compromising on efficiency or environmental performance. The design SO₂ emissions are less than half the normal legislated level and emissions of NO_x are much better than required through use of advanced low-NO_x burners and over-fire air. The fabric filtration unit takes the concentration of particulates down to better than design.

The cost of Genesee phase 3 was approximately 1100 USD/kWso in 2005, excluding interest during construction or owners costs, and construction took 36 months. The power generating and emission control equipment was established through a single EPC contract.

The sliding pressure design used here allows economically competitive, flexible plants that will be suited to de-regulated environments elsewhere in North America. It has been a low-risk way of achieving high efficiency and environmental performance on sub-bituminous coals. After construction of a sister unit at a neighbouring TransAlta power generation site, later plants are likely to move to higher steam parameters, following the success of this and similar units currently being constructed in Canada and the USA.

Isogo New Unit 1, Japan

Isogo New Unit 1 is a sea water cooled, 600 MWe ultra-supercritical unit, owned by Electric Power Development Co. (J-POWER). It is located at Yokohama City, 25 km from Tokyo. The plant, opened in April 2002, burns Japanese and internationally-traded bituminous coals and some sub-bituminous coal. Very high steam conditions give a good efficiency of over 42% net, LHV basis (40.6%, HHV basis) at this rather warm sea water cooled site. Advanced steam parameters (25 MPa/600°C/610°C) were made possible by the availability of recently developed steels. The configuration includes a once-through wall-fired tower boiler fitted with combustion measures for low-NO_x, a single reheat advanced supercritical steam turbine cycle, with eight stages of feedwater heating, an SCR, ESPs, and a dry FGD.

Isogo New Unit 1's environmental performance is very impressive. The plant easily meets extremely tight emissions levels on NO_x, dust and oxides of sulphur. The flue gas desulphurisation system is a dry regenerable process which uses activated coke to capture the SO₂. It consumes less power and much less water than wet systems. J-POWER are marketing the technology under the name of ReACT as a multi-pollutant control system for oxides of sulphur, NO_x and particulates, as well as heavy metals such as mercury. Virtually all solid by-products are utilised at Isogo.

The contracting strategy was to use owner design basic specification and the approximate capital cost was 1800 USD/kWso (2006), based on Isogo New Units 1 and 2 (latter not yet completed), including interest during construction and owner's costs. Construction time was 66 months.

Isogo New Unit 1 is a flagship PCC plant. It uses the highest steam parameters in the world for a modern sliding pressure system, and close to zero emissions

of conventional pollutants have been achieved. The Isogo New Unit 2, construction of which commenced in October 2005, will have even higher steam conditions (25MPa/600°C/620°C) and use the ReACT system for multi-pollutant control.

Younghung Thermal Power Plant, Republic of Korea

Younghung Thermal Power Plant, owned by the Korean South-East Power Company (KOSEP), is the newest coal-fired plant in Korea. The first two units, opened in 2004, have supercritical steam parameters of 24.7 MPa/566°C/566°C. Younghung is located at Incheon, approximately 50 km from Seoul. The units are sea water cooled, rated each at 800 MWe, and fire internationally-traded bituminous coals. These are the largest coal-fired units to be built in Korea to date and have used higher steam conditions than previous plants in the country. A single reheat supercritical steam turbine system of conventional configuration with eleven stages of feedwater heating is used and design net efficiency is 43% on an LHV basis (41.9%, HHV basis). The aim is to establish twelve units on the site. Construction of Units 3 and 4 is in progress. These will be similar, but use higher steam temperatures of 593°C.

A combination of environmental control systems gives very good environmental performance. Low-NO_x combustors and air staging in the boiler provide initial NO_x minimisation, and an SCR unit removes much of the remaining NO_x. Particulates are removed by ESPs, and 60% of the ash is utilised. A limestone/gypsum FGD system removes SO₂. By-product gypsum is sold to the construction industry.

The plant specific capital cost was 993 USD/kWso in 2003, but the basis is uncertain. Construction time was 64 months.

Thus, low emissions of conventional pollutants have been achieved in a cost-effective plant using conventional commercial systems. In Korea, plant designs are now moving toward higher conditions quite rapidly, and succeeding unit additions at Younghung will have progressively higher steam parameters.

Wangqu 1 and 2, China

Wangqu opened in 2006, and is owned by Shanxi Lujin Wangqu Power Generation Co. Ltd. It is at an inland location, 2 km from Lucheng City near Changzhi. The two new 600 MWe (nominal) units, completed in 2006, have a design net efficiency of over 41% on an LHV basis (40%, HHV basis). They represent a major step forward in being among the first wall-fired supercritical boilers to operate successfully using lean coals (10 to 20% V.M.) by employing advanced low NO_x burners together with high velocity over-fire air. Due to pressure to send the best coals to steelmaking, China's power stations increasingly need to burn such coals.

Each unit has a two-pass supercritical boiler, a single reheat supercritical cycle with eight stages of feedwater heating, ESPs and a wet FGD. Steam parameters are 24.2 MPa/566°C/566°C, chosen to minimise risk, while giving good performance.

The combustion system has been developed to meet Chinese legislation on NO_x emissions from new lean coal-fired plant even at low loads with good combustion efficiency. The SO₂ removal design efficiency at the plant is also good.

The contracting strategy used by the client was owner design specification with competitive bidding. The installation cost was approximately 580 USD/kWso in 2006. This figure is understood to exclude owner's costs and interest during construction. Construction time was 30 months.

These units are a good example of the way China is moving rapidly to improve the efficiency and emissions of its power plants by ordering high-performing international technology with licensing agreements to enable the country to use its own manufacturing capabilities for future plants. Two further identical 600 MWe units at the site will be air cooled, as Shanxi province has a water shortage problem.

Suratgarh, India

Suratgarh thermal power plant consists of five 250 MWe subcritical units commissioned between 1998 and 2003. It is owned by the Rajasthan State Electricity Board and is situated in the northern part of Rajasthan in the Ganganagar district on the edge of the Thar/Indian desert. A single reheat subcritical steam turbine system of conventional configuration with six stages of feedwater heating is used for each unit, and design efficiency is 37.1% on an LHV basis (35.1%, HHV basis). Steam parameters are 15.8 MPa/540°C/540°C. The units are water cooled, with mechanical draught cooling towers. Ambient conditions here result in a higher condenser pressure (10.5 kPa) than encountered in more temperate regions.

High efficiency ESPs are fitted for particulates control, and tangential firing and over-fire introduction of secondary air are used for NO_x control. There is no SCR or FGD. Ash utilisation has grown steadily, and Suratgarh plans achieving 100% utilisation by 2010.

The units were designed to use indigenous coals of ash content 45% but the fuel used is now a blend, including some Chinese coal, to keep to around 30% in line with Government requirements to use maximum 34% ash coal. This is still high by world standards. Other challenges were associated with the desert environment giving difficult site ground conditions and water quality variations. Low rainfall necessitated construction of a reservoir for 21 days' operation. Air intakes are designed to avoid ingress of sand during sandstorms.

The plant specific capital cost was approximately 822 USD/kWso in 2002, but the basis of this was uncertain. Construction time for one unit was 39 months.

The thermal efficiency is inevitably penalised by the coal quality as well as the local conditions and the use of a subcritical cycle, but future, higher efficiency supercritical units will be able to build on the experience gained.

Majuba, South Africa

Majuba is another plant in an area of water shortage firing high ash coal, in this case of around 30% ash content and of slagging and fouling propensity. The plant is owned by Eskom and is situated near Amersfoort in Mpumalanga. The coal for the 4110 MWe power station is brought from collieries in the Witbank area of Mpumalanga. Majuba consists of six units of over 600 MWe. The first opened in April 1996 and the others followed at yearly intervals.

Each unit uses a subcritical once-through tower boiler of steam parameters 17.2 MPa/540°C/540°C and a single reheat subcritical steam turbine. Units 1-3 employ air cooling and units 4-6 have water cooling. Six stages of feedwater heating are used for both types. The design efficiencies of the dry-cooled and wet-cooled units are around 35% and 37% net on an LHV basis (33.8% and 35.7%, HHV basis), respectively.

Low-NO_x burners give control of NO_x. Staggered burner geometry is used to minimise slagging. There is no SCR or FGD. Fabric filtration systems remove particulates.

In the dry-cooled condensers, steam from the turbines is condensed inside tubing, across which air is blown. Condensing performance is very dependent on ambient temperature, so unit output and efficiency vary considerably with season. The wet cooled units have conventional condensers and natural draught cooling towers. Wet cooling was selected for these units for economic reasons.

The specific capital cost of Majuba was approximately 410 USD/kW_{so} in 2001, including interest during construction and owner's costs. The plant is currently two-shifting and performing well, despite being intended for base load use.

Dry cooled units are less efficient than conventional systems and efficiency is also affected by the use of a subcritical cycle. Dry cooling would be considered for future plants, depending on water availability. Eskom is understood to be currently in the bidding stage for 3x660 MW supercritical power plants.

Natural gas-fired plant: Enfield, United Kingdom

The Enfield Energy Centre combined cycle plant in northeast London opened for commercial production in 2002 and is currently owned by E.ON. It is a 400 MWe system, based on a reheat gas turbine and reheat steam cycle. The design efficiency is 58% net on an LHV basis (52%, HHV basis). The combined cycle turbine is currently offered by the manufacturer with an efficiency of 58.5% (LHV).

Enfield employs Alstom's GT26B gas turbine, which has two combustion zones, with a high pressure expansion turbine between them and a low pressure turbine after the second combustor. The system was developed to give high efficiency without the need for the highest turbine inlet temperatures. The hot exhaust gases raise steam at three pressure levels for a subcritical reheat steam turbine, which is coupled to the same generator. The steam cycle here has an air cooled condenser.

The gas turbine uses a sequential annular combustion system and low-NO_x burners to keep NO_x production low without needing an SCR unit.

NGCC projects are lower in investment requirements than coal-fired projects in OECD locations. In this case, the total project cost was around USD350 million, or around 950 USD/kW_{so} in 1999. The overnight cost will have been considerably lower. Gas turbine combined cycle projects have short construction times, and here it was 22 months. Enfield currently operates on a flexible, two-shift basis but efficiency is still high at 52% (LHV).

This plant highlights a continuing drive by manufacturers to move the technology on to higher future performance through innovation. High efficiency and lower capital requirements mean natural gas-fired combined cycles will continue to be specified for many power generation projects where natural gas is available.

IGCC technology review

Net efficiency for IGCC in existing plants is around 40-43% on an LHV basis (around 38-41%, HHV basis). Recent gas turbines would enable this to be bettered and future developments should take efficiencies beyond 50% on an LHV basis. Emissions are low, and mercury removal will be cheaper than for PCC. The specific investment cost of IGCC is about 20% higher than that of PCC. There is however more uncertainty in IGCC costs as there are no recently built coal-fuelled IGCC plants and the existing ones were constructed as demonstrations. Availabilities have also not yet reached the demonstrated level of operating PCC units. Suppliers have plans to bring the capital cost to within 10% of that of PCC. Note that, while there are competitive pressures, the capital costs being cited for many power projects have risen sharply recently because of increases in energy prices and their impacts on steel and concrete costs.

There are two demonstration plants in the EU. NUON's plant, at Buggenum in Holland, is a 250 MWe system, based on Shell gasification and a Siemens V94.2 gas turbine. It now operates as a commercial plant on imported coals with good availability and a net efficiency of 43% (LHV). The other is ELCOGAS's plant at Puertollano in Spain, a 300 MWe system based on the similar Prenflo gasifier and a Siemens V94.3 gas turbine. It uses a high ash coal/high sulphur petcoke mixed fuel and has a net efficiency of 42% (LHV). Both had initial problems in firing syngas and needed turbine combustor modifications. Both have highly integrated systems, which have proved to be rather inflexible. A 1200 MWe plant at another site is planned by NUON.

IGCC plants currently operating in the USA are the Tampa Electric Polk project and the Wabash River coal gasification project, both constructed under the US DOE CCT Program. The 250 MWe Polk project uses a GE gasifier and GE 7FA gas turbine. The net efficiency was 35.4% on an HHV basis (36.7%, LHV basis) on coal feed. The 260 MWe Wabash River project uses ConocoPhillips E-Gas technology with a GE 7FA turbine and an existing steam turbine and has a net efficiency of over 38% on an HHV basis (40%, LHV basis). Both US plants are less integrated than the EU ones although some gas turbine air extraction has recently been incorporated at the Polk plant. The gas turbines performed well at both but there were some other difficulties. Both plants now operate commercially, although their availabilities are understood to be lower than the best in class operating supercritical PCC plants in the USA. A CCPI demonstration of the transport gasifier is to be constructed in Florida.

In Japan, the Clean Coal Power R&D Co., Ltd. (CCP) is constructing a 250 MWe IGCC demonstration project, due to start operation in 2007, at Iwaki City, based on the MHI air-blown entrained gasifier and an MHI gas turbine.

IGCC reference plant designs of 600 MWe have been developed by supplier groupings to encourage market uptake by driving down the cost and providing full single-point guarantees. Examples are those from GE-Bechtel and Siemens with ConocoPhillips. Some projects likely to use these include:

- ▲ Duke Energy, Edwardsport, Indiana – GE-Bechtel
- ▲ AEP, Meigs County, Ohio and Mason County, W. Virginia – GE-Bechtel
- ▲ Mesaba Energy Project, Minnesota – ConocoPhillips E-Gas (CCPI Demo)

With IGCC now available as a commercial package, more orders could follow as utilities see the cost decreasing and availability improving. It may still be necessary for subsidies or incentives to cover the higher cost compared with PCC.

IGCC fits well with CO₂ capture and storage and there are projects planned in several countries, including Canada, Australia, Germany, the UK, in addition to the US Government FutureGen and European Commission Hypogen initiatives and the GreenGen project in China. Inclusion of CO₂ capture and storage will reduce efficiency but the generation cost may be lower than for CO₂ capture on PCC.

Conclusions

Table S2 collects together the case studies with a summary of costs, emissions and efficiencies.

In the near future, leading edge supercritical pulverised coal technology in the EU and Japan will continue gradually to move to higher steam conditions, with in some cases simplification of cycles, in others, more complex systems. The current state-of-the-art for modern, sliding pressure-capable PCC boilers is 600°C main steam and 620°C reheat at the turbine. In other regions there

will be a follow-up move through increasing conditions while keeping just behind the state-of-the-art in order to take advantage of the experience in the new plants, while minimising risk. Although even higher temperatures have been used in the past on early supercritical designs in the USA and elsewhere, these had availability difficulties and were not competitive. In due course, leading edge plant is likely to be built in all locations.

In some countries, such as India and China, subcritical plants will probably be built in addition to supercritical units for a while. Local manufacturing bases for current plant are now capable of supplying supercritical technology so there will be movement toward the most advanced steam conditions. Other countries, not yet using or building supercritical technology, will likely begin orders at some point within the next few years. The UK, Australia and South Africa are examples.

Advanced developments in natural gas-fired gas turbines will take the efficiencies of these systems to even higher levels, maintaining their strong presence for new power projects. Developments in gas turbines will benefit commercial offerings for turbines in coal IGCC. With IGCC now available as a commercial package, orders should follow, probably aided at first through market entry incentives.

At some point, it looks highly likely that fossil-fired plants will capture and store their CO₂ emissions. CO₂ capture will reduce efficiency markedly, so there will be a continuing need to use innovations such as those identified in these case studies. Future very high temperature PCC systems employing superalloys should enable power generation efficiencies with CO₂ capture to be comparable with those of current non-capture plants. High temperature hydrogen gas turbines and new CO₂ separation methods should give IGCC with CO₂ capture systems of similar performance, so both combustion-based and gasification-based platforms are likely to be important in the future.

The following main points have emerged from the case studies and subsequent analysis of results:

- ▲ New PCC projects use S/C or USC conditions as a matter of routine to achieve high efficiency;
- ▲ USC and S/C PCC systems are available for a wide range of coal types;
- ▲ Use of new materials has been important in achieving the high efficiency and reliability;
- ▲ Complex thermodynamic cycles have evolved to enhance efficiency further;
- ▲ Heat extraction to low temperatures has been demonstrated using non-metallic components in heat exchangers;
- ▲ Siting helps efficiency;
- ▲ Flexibility is no longer a problem in S/C or USC;
- ▲ A wide range of coal types can be burned in PCC systems;

Table S2 • Costs, emissions and efficiencies of the case study plants and comments

Plant	Capital cost, USD/kW _{so}	Achieved emissions at 6% O ₂ , dry	MWe net	Steam conditions MPa _a /°C _f /°C (°C)	Design efficiency, net %, LHV and HHV bases	Annual operating efficiency, net %, LHV and HHV bases	Factors affecting efficiency and other comments
Europe – Denmark: Nordjyllandsværket 3	1500 (2006) for new 800 MWe excluding owners costs or IDC	NOx 146 mg/m ³ SO ₂ 13 mg/m ³ Dust 18 mg/m ³	384	29/582/580/ 580	47 LHV (no heat load) 44.9 HHV (no heat load)	47 LHV (not annual) 44.9 HHV (not annual)	High steam parameters Cold sea water cooling Double reheat Low auxiliary power Extremely low emissions No solid waste for disposal
Europe – Germany: Niederaussem K	1175 (2002) Total project cost	NOx 130 mg/m ³ SO ₂ <200 mg/m ³ Dust <50 mg/m ³	965	27/580/600	43.2 LHV 37 HHV	43.2 LHV (base load) 37 HHV (base load)	Lignite fuel, 50-60% moisture content High steam parameters Large cooling tower for low condenser pressure Innovative heat recovery systems Low auxiliary power
North America – Canada: Genesee 3	1100 (2005) Overnight cost	NOx 170 mg/m ³ SO ₂ 295 mg/m ³ Dust 19 mg/m ³	450	25/570/570	41.4 LHV 40 HHV	41 LHV (base load) 39.6 HHV (base load)	Moderately high steam parameters Low auxiliary power First N American sliding pressure supercrit. Sub-bituminous coal
Asia – Japan: Isogo New Unit 1	1800 (2006) Total project cost incl New Unit 2 under construction	NOx 20 mg/m ³ SO ₂ 6 mg/m ³ Dust 1 mg/m ³	568	25/600/610	42 LHV 40.6 HHV	42 LHV (base load) 40.6 HHV (base load)	High steam parameters Moderately warm sea water cooling Low auxiliary power Low power demand FGD Extremely low emissions No solid waste for disposal

Table S2 • Costs, emissions and efficiencies of the case study plants and comments (continued)

Plant	Capital cost, USD/kW _{so}	Achieved emissions at 6% O ₂ , dry	MWe net	Steam conditions MPa/°C _f /°C (°C)	Design efficiency, net % LHV and HHV bases	Annual operating efficiency, net % LHV and HHV bases	Factors affecting efficiency and other comments
Asia – Korea: Younghung	993 (2003) Basis uncertain	NOx 83 mg/m ³ SO ₂ 80 mg/m ³ Dust 10 mg/m ³	2x774	25/566/566	43.3 LHV 41.9 HHV	41 LHV (capacity factor not known) 39.7 HHV (capacity factor not known)	Moderately high steam parameters Very low emissions Low auxiliary power
Asia – China: Wangqu 1, 2	580 (2006) Overnight cost	NOx 650 mg/m ³ SO ₂ 70 mg/m ³ (des) Dust 50 mg/m ³	2x600	24/566/566	41.4 LHV 40 HHV	New plant - no operating history	Moderately high steam parameters Low auxiliary power Advanced low-NOx lean coal combustion system
Asia – India: Suratgarh 1-5	822 (2002) Basis uncertain	SO ₂ unabated Dust 50 mg/m ³ (unit 5)	5x227	15/540/540	37.1 LHV 35.1 HHV	33.9 LHV (base load) 32.1 HHV (base load)	Subcritical cycle High ash coal
Africa – South Africa: Majuba 1-6	410 (2001) Total project cost	SO ₂ unabated Dust 50 mg/m ³	3x612 (dry); 3x669 (wet)	17/540/540	35-37 LHV 33.8-35.7 HHV	34 LHV (two-shifting) 32.8 HHV (two-shifting)	Subcritical cycle High ash coal Dry cooling from water supply constraints
Europe – United Kingdom: Natural gas plant: Enfield	950 (1999) Total project cost	NOx 128 mg/m ³ SO ₂ negligible Dust zero	373	Advanced GTCC	58 LHV 52 HHV	52 LHV (40% capacity factor) 47 HHV (40% capacity factor)	Combined cycle with reheat gas turbine Low auxiliary power Zero solid waste
IGCC general review	PCC+20%	NOx 50-75 mg/m ³ SO ₂ ~20 mg/m ³ Dust <1 mg/m ³	300/module	IGCC	40-43 LHV 38-41 HHV		Combined cycle Syngas-fired gas turbine Inert solid waste

- ▲ The operating efficiencies of the base-loaded plants generally lay close to design values;
- ▲ Efficiency and economics are unavoidably impaired by the use of dry cooling;
- ▲ Efficiency bases vary and scrutiny is needed to avoid misleading comparisons – e.g. basis of LHV;
- ▲ Virtually zero conventional emissions are possible now from PCC as well as IGCC;
- ▲ Tailoring plant design to the requirements of the coal feed can result in high performance and low environmental impact while saving in cost – e.g. by omitting SCR;
- ▲ Environmental performance is often better than design;
- ▲ Higher efficiency plants have lower CO₂ emissions;
- ▲ Combined heat and power systems have highest overall efficiencies;
- ▲ PCC specific capital costs after bringing to a common basis correlate broadly with steam parameters and with efficiency;
- ▲ Capital costs are rising for new projects (not just PCC) because of increased energy and raw material costs;
- ▲ PCC unit construction times vary considerably depending on site constraints;
- ▲ Manning levels in non-OECD plants appear in some modern plants to have become more in line with OECD practice;
- ▲ Ash sales depend strongly on local circumstances;
- ▲ The costs of ash disposal are highly location-specific and uncertain as they may represent a marginal cost or creation of a new disposal site;
- ▲ Delivered coal prices in non-OECD countries appear now to be broadly in line with coal prices in other parts of the world, in the range of 1.5-2.5 USD/GJ;
- ▲ Future PCC efficiencies of above 50%, LHV basis (approaching 50%, HHV), are envisaged within 10 years;
- ▲ IGCC could play a major role if the recent commercial offerings succeed;
- ▲ IGCC could also reach 50% efficiency, LHV basis (approaching 50%, HHV), within similar timeframe to PCC;
- ▲ Natural gas-fired CCs are more efficient and less expensive and quicker to construct than systems based on coal;
- ▲ Intrinsically high efficiency is vital as basis of future plants using CO₂ capture and storage.