



Carbon Dioxide Capture from Coal-Fired Power Plants in China

Summary Report for NZEC Work Package 3
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Executive Summary

This report draws on the capture plant case studies by NZEC Work Package 3 partners to present, in a unified and consistent form, the technical and economic performance of power generation with CO₂ capture in China. Complementary work on performance calculations by Chinese and UK partners has been combined where appropriate to give estimated final overall plant efficiencies and CO₂ emission levels. Estimated capital costs have been used to derive levelised costs of electricity and emission abatement costs on a consistent basis.

Advanced new build capture technologies that have still to be demonstrated, oxyfiring, post-combustion with aqueous ammonia and pre-combustion capture on IGCC, are predicted to achieve similar power plant efficiencies of 35.6, 35.7 and 36.8% respectively. CAPEX values for these plants are approximately 9000 to 10000 RMB/kW net, with an estimated +/- 30% uncertainty. Levelised costs of electricity for these options are estimated to have a range of approximately 370-410 RMB/MWh for a coal cost of 16 RMB/GJ and approximately 40% higher for a coal cost of 32 RMB/GJ. Costs of abatement are calculated relative to the standard alternative plant that would be built, an advanced supercritical plant. Since the cost of abatement is based on the differences between relatively larger numbers there is more variance in the results, from an estimated 140 RMB/tCO₂ for oxyfiring to 200 RMB/tCO₂ for IGCC+CCS. These values are, however, very sensitive to estimates for capture plant costs, particularly the additional capital costs, and should be regarded as preliminary.

Post-combustion capture with an MEA-based solvent, an older technology, is predicted to have a generally less favourable performance. Polygeneration of electricity and methanol also appears to have a low efficiency and high capital costs, but the methanol production is not taken into account.

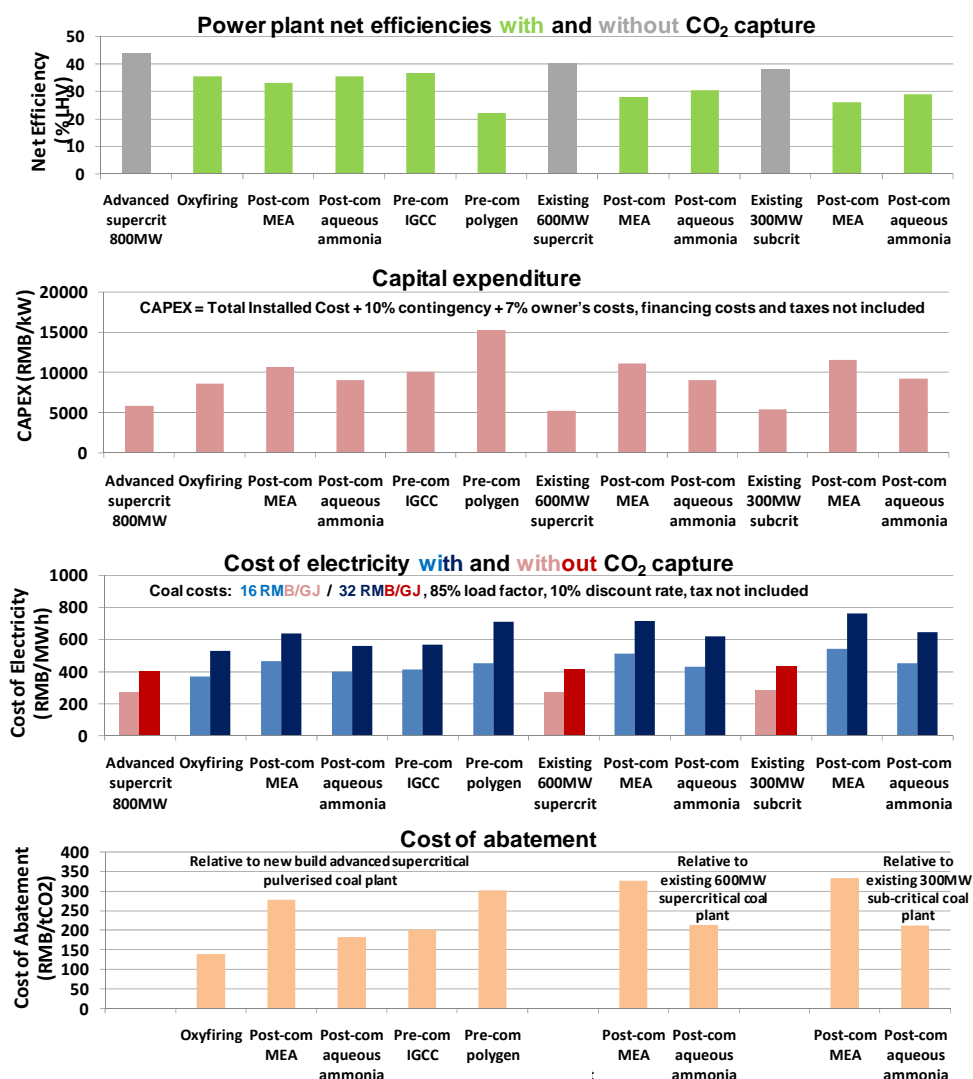


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1. Background and supporting case study reports

1.1 Background and scope

This report draws on the following capture plant case studies by NZEC Work Package 3 partners. Salient features of these studies are presented in this summary report but for detailed information readers should refer to the original source(s). These are indicated in the text by the appropriate partner abbreviations shown in brackets after section headings.

The principal purpose of this report is to present in a unified and consistent form the technical and economic performance of the main capture case studies. Complementary work on performance calculations by Chinese and UK partners has been combined where appropriate to give final overall plant efficiencies and CO₂ emission levels. Estimated capital costs have been used to derive levelised costs of electricity and emission abatement costs on a consistent basis. These are presented in graphical and tabulated forms.

1.2 Contributing NZEC Work Package 3 Reports

Partner Abbreviation	Full Name	Report Title
DB	Doosan Babcock Energy Limited	J R Gibson and D Schallehn, <i>China – UK Near Zero Emissions Coal (NZEC) – Oxyfiring Options</i>
DCE	Tsinghua University, Department of Chemical Engineering	Que Zheng and Jian Chen, <i>Cost estimation for CO₂ Capture with a MEA absorption process</i>
DTE	Tsinghua University, Department of Thermal Engineering, Key Laboratory for Thermal Science and Power Engineering of Ministry of Education	Wang Shujuan, <i>Carbon Dioxide Capture Using MDEA and Ammonia Solutions</i>
GG	Greengen Co., Ltd, Beijing	<i>Case Study for IGCC Power Plant In China (with CCS)</i>
IMP	Imperial College London, Mechanical Engineering Department, Energy Technology for Sustainable Development Group	Mathieu Lucquiaud, <i>Steam cycle calculations for capture-ready steam cycle and retrofits with MEA, ammonia and MDEA solvents</i>
NCEPU	North China Electric Power University, Key Lab of Condition Monitoring and Control for Power Plant Equipment of Ministry of Education	Yongping Yang, Gang Xu and Liqiang Duan, <i>Carbon Dioxide Capture from Existing Coal-Fired Power Plant in China</i>
THCEC	Tsinghua University, BP Clean Energy Research & Education Centre	XU Zhaofeng, <i>Polygeneration using two-stage slurry gasifier with CCS</i>
WHU	Wuhan University	Hu Jicai and Li Ji, <i>CO₂ Transport</i>
ZJU	Zhejiang University, State Key Laboratory of Clean Energy Utilization	Mengxiang Fang, Shuiping Yan and Zhongyang Luo, <i>Carbon Dioxide Capture from a New-built Ultra Supercritical PC Power Plant</i>

2. Power generation from new build pulverised coal plants with CCS (DB, DCE, DTE, IMP, NCEPU, ZJU)

2.1 Advanced supercritical base plant for new build case studies with and without capture (DB)

New-build, pulverised coal (PC) capture studies are based on Advanced Supercritical (ASC) Boiler Turbine (BT) technology. Advanced supercritical boilers are already operating in China, with an estimated Total Installed Cost of 5000 RMB/kW based on Chinese partners' experience. Present state-of-the-art advanced supercritical boiler/turbine technology is used, with steam turbine inlet conditions of 280 bar / final superheat temperature of 600°C / final reheat temperature of 610°C, giving an efficiency for the site and coals specified of 43.9% LHV net. Emissions controls consist of DeNOx, particulate removal and DeSOx plant. A unit with an output of 824.3 MW net is used as the base case for new build pulverised coal options with capture. This size of unit is typical for new advanced supercritical boilers planned in Europe and also gives PC capture options with net MW outputs that are close to the limiting size for IGCC+CCS options. Larger PC base units (e.g. 1000-1200 MW) are feasible and are likely to be built in China, but the output of the IGCC+CCS unit is limited by the size of the largest gas turbines available.

A block flow diagram for the base case ASC PC plant is shown in Figure 2-1. A brief description of each of the units identified in the block flow diagram is given below, with a sub-section adding how, if at all, it might need to be modified for use in a PC-based capture plant. The base case unit burns coal in air and so also do the post-combustion capture cases; the base plant design remains essentially unmodified for these apart from the Turbine Island. For oxyfiring capture, the coal is burnt using oxygen instead of air, mixed with recycled combustion products at the burners to moderate flame temperatures. For oxyfiring capture certain aspects of some the units in the base plant design will have to be changed while others would be used unaltered, as indicated.

Boiler: The advanced supercritical boiler is based on the state-of-the-art Doosan Babcock Two-Pass single reheat BENSON boiler with Posiflow™ Technology, Balanced Draught, and Gas Biasing for reheat steam temperature control.

Coal and ash handling: A conventional system is employed, with the design of the furnace bottom ash and fly ash systems from the boiler and downstream particulate removal systems following modern conventional air fired power generation plant practice which aims to minimise tramp air ingress.

Pulverised Fuel Milling Plant: Coal will be milled using conventional pulverisers. In this case, tube

mills are selected to pulverise the coal to a suitable fineness (typically >80% passing through 75microns). If the coals are inclined towards sub-bituminous coals then roller or ball mills could be substituted.

Modifications for capture cases: In any pulverised fuel combustion plant with a direct firing system the primary gas supplied to the mill is required to both dry the as-fired coal and to convey the pulverised coal from the mill to the burners. In the case of air firing, hot combustion air is supplied from the air/gas heater, and in the case of oxyfiring, flue gas is recycled from the FGD outlet and passes through a gas/gas heater. The ability of the primary gas to dry the fuel is driven by two factors, the overall temperature and heat capacity of the gas entering the mill, and its moisture content. In both oxyfiring and air firing the temperature of the primary gas is similar, although the volumetric heat capacity of recycled flue gas is greater than that of air due to the higher density of CO₂ compared to nitrogen. When operating in air firing mode the moisture in the combustion air (i.e. its relative humidity) is low, making the drying process easier as the air has a high capacity to absorb evaporating moisture. For oxyfiring operation the raw recycled flue gas typically has a substantially higher moisture content which limits the drying capacity. This reduction in drying capacity can be mitigated by both increasing the mill outlet temperature (although there are practical limits to this) and by reducing the moisture content of the recycled flue gas.

Turbine Island: State of the art advanced supercritical turbine technology will be utilized.

Modifications for capture cases: This will be used without modification from the air-firing design for oxyfiring, but with provision for steam extraction after the intermediate pressure (IP) cylinder for post-combustion capture (see section 2.3.3 below). Rejected heat from the capture equipment is used to minimise the steam extraction for feed water heating for all capture options.

DeNOx: New build plant is required to meet NOx emissions regulations (450mg/Nm³ @ 6%O₂). Technologies based on primary NOx reduction measures, (low NOx burners and overfire air (OFA)), and secondary measures, (Selective Catalytic Reduction (SCR)), can be used.

Modifications for capture cases: DeNOx plant is not a requirement within the oxyfiring boiler island as the NOx is captured in the downstream compression plant. However, DeNOx plant will need to be installed for post-combustion capture cases with air firing.

ESP: Particulate removal plant is essential to both meet dust emission level limits, as defined by the applicable environmental legislation, and to protect downstream flue gas fans and blowers from excessive erosion. Electrostatic Precipitators (ESP) are used in the NZEC base case.

Modifications for capture cases: When operating in oxyfiring mode the particulate removal plant ensures that the FGR streams are relatively dust free. The proposed oxyfiring and post-combustion

plants both also utilise an ESP. Previous studies have shown that, as a direct result of the performance of the airheater / gas-gas heater module, the operating temperature of the electrostatic precipitator (ESP) is increased during oxyfiring operation to typically between 160°C and 200°C. Normally higher temperatures lead to less gas residence time in the ESP with a resulting loss in particulate collection efficiency. However, oxyfiring flue gas has a higher density than air-fired flue gas and this mitigates the loss in efficiency arising from the increased temperature.

DeSOx: For air-firing an FGD is required to meet emissions legislation.

Modifications for capture cases: Particular attention will be given to achieving a very high level of removal (<30 ppm) for post-combustion systems to minimize solvent loss. The FGD plant also cools the flue gas by evaporative cooling. In oxyfiring mode, an FGD plant is used to treat the flue gas to ensure that the primary and secondary flue gas recycle streams lead to sulphur dioxide (SO₂) and sulphur trioxide (SO₃) concentrations in the furnace that are no worse than the equivalent experience for high sulphur coals with air firing¹ and residual SOx is removed by processing as the CO₂ is compressed.

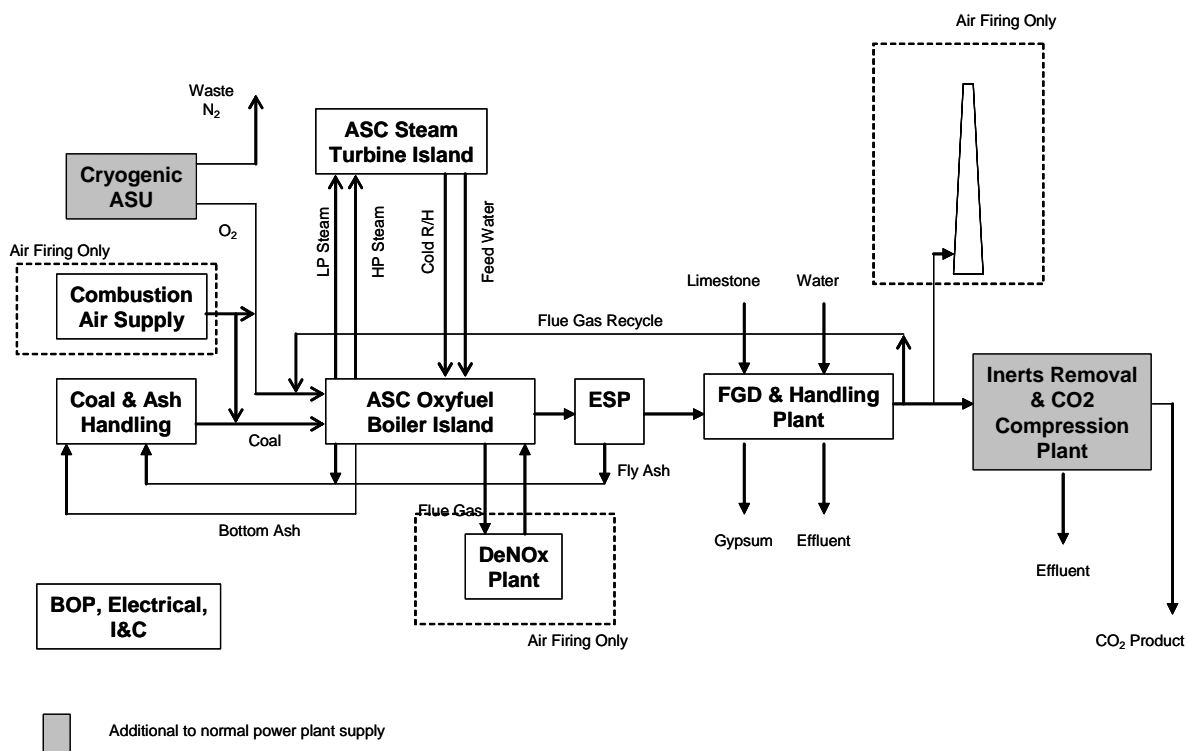


Figure 2-1 Advanced supercritical steam plant, also showing scope of equipment for use as the base plant for air firing with post-combustion capture and with oxyfiring (flue gas recycle for oxyfiring only)

¹ For very low sulphur coals, with a sulphur content of 0.2% w/w daf or lower, FGD is not expected to be required for oxyfiring operation. Coals with somewhat higher sulphur levels might also be satisfactory for oxyfiring operation without using an FGD but this would depend on the coal calorific value and hence firing rate and also on the details of the flue gas recycle approach adopted.

2.2 CO₂ capture using oxyfiring (DB, ZJU)

Overall, the key features of oxyfiring vs air firing are:

- Incorporation of an air separation unit for removal of N₂ to supply a nearly pure O₂ stream into the recycled flue gas for the combustion process.
- Recirculation of flue gas back to the boiler (via an FGD for the NZEC coals) providing a transport medium for the pf and to maintain the radiative and convective heat transfer characteristics of the furnace and boiler.
- Incorporation of gas-gas heaters instead of conventional air-preheating arrangements.
- Incorporation of a flue gas cooler and condenser to recover heat into the steam cycle condensate and feedwater preheating systems.
- CO₂ compression and inerts separation plant, incorporating additional sulphur removal

This is considered a low risk approach for an operator needing to be able to maintain electrical output because the plant designs retain full air firing capability, minimising commercial and technical risk should the oxyfiring components be unavailable, by allowing continued generation if the oxyfiring plant is out of service. It is envisaged that an air firing capability will only be applied to the initial demonstration plants, however, as there are significant costs associated with retaining this on an oxyfiring plant.

This configuration thus offers an evolutionary approach from well known and understood plant:

- The plant is designed with operational and practical experience of air-firing.
- Similarities in design and operation to conventional air fired, pulverised coal power plants for each of the major plant systems and components.
- New plant systems (ASU, compressors) and components are well proven designs and commercially available at the required capacities.

The oxyfiring case study by Doosan Babcock has shown that for an advanced supercritical power plant designed to capture CO₂ the penalty in terms of cycle efficiency is 8.3 percentage points compared with an air fired case with no CO₂ capture, giving a final efficiency of 35.6 % LHV net. This penalty has been mitigated by recovering heat within the system to offset the additional power consumption of the CO₂ compression plant and air separation unit. An approximate estimate is that capital costs for such an oxyfiring plant will be 48% higher on a RMB/kW basis than for a conventional air-fired plant (but based on UK experience, rather than direct Chinese market costing), giving a Total Installed Cost of 7390 RMB/kW for an assumed base plant TIC (based on estimates from Chinese partners) of 5000 RMB/kW. Unlike post-combustion CO₂ capture systems, oxyfiring plants do not need to make up any CO₂ capture solvent losses, so this fairly significant contribution to running costs is avoided.

2.3 Post-combustion CO₂ capture (DCE, DTE, IMP, NCEPU, ZJU)

Post-combustion CO₂ capture based on the use of monethanolamine (MEA) solutions was studied in conventional packed absorber columns (DCE) and in membrane contactors (ZJU – also see Appendix C). While the latter offer potential advantages for gas and solids handling, the selected membrane materials were limited to more dilute MEA solutions (20% w/w) than the packed columns (30% w/w). This meant that the performance of the membrane system was worse and therefore no results are reported in the detailed cost comparison; additional work is needed on this novel approach if it is to have the potential of becoming competitive with other options. Similarly, the use of methyldiethanolamine (MDEA) in a conventional packed column, examined by DTE, is also not reported in this summary since it did not appear to offer any significant advantage over MEA.

The use of aqueous ammonia as a CO₂ solvent was also studied by DTE. While still requiring further development work this approach appears to have the potential to offer significant advantages in terms of reduced energy penalty and capital costs. It has therefore been included in the comparative analysis as a possible example of the benefits that improved post-combustion capture, using this or other 'second generation' solvents, may be able to deliver, compared with plants using designs based on the 'industry standard' MEA solvent.

2.3.1 MEA post-combustion capture system (DCE)

A schematic flow diagram for the MEA capture process is shown in Figure 2-2.

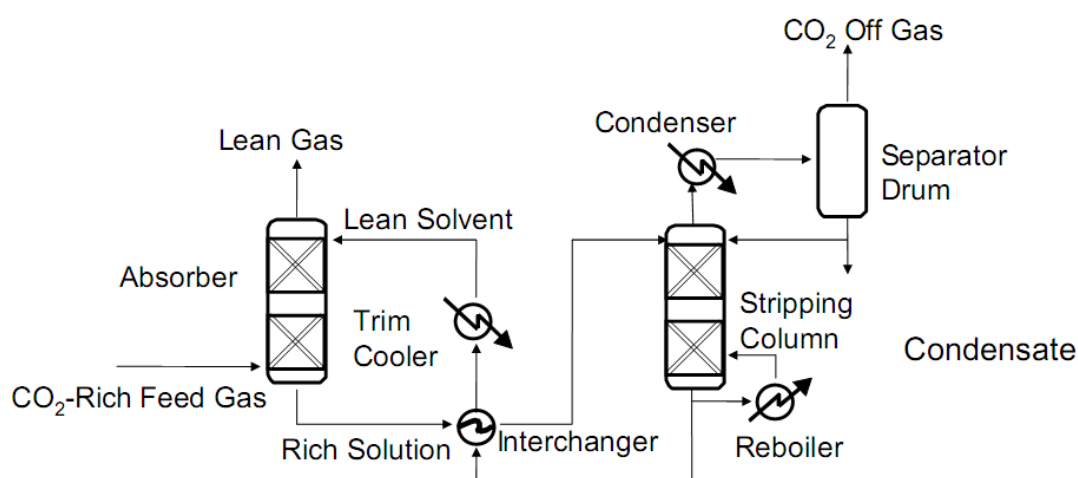


Figure 2-2 Process flow diagram for MEA capture

The conventional MEA process is a temperature swing absorption process. The removal of CO₂ from flue gas is achieved by contacting the feed flue gas in an amine absorber with an aqueous solution of an alkanolamine at a low temperature, where the carrier solution, an aqueous amine solution absorbs CO₂ to form carbamate or bicarbamate ions and become a CO₂-rich solution. Meanwhile, CO₂ is removed from the flue gas. In a solvent regenerator, the CO₂-rich solution then liberates the dissolved CO₂ at an elevated temperature to reverse the absorption reaction and becomes a lean solution. A high purity CO₂ stream is released from the solvent regenerator and is then compressed to 110 atmospheres. The regenerated CO₂-lean amine solution is then cooled and recycled to the amine absorber from the solvent regenerator for further CO₂ removal. Both thermal energy and electrical energy, the latter principally for solvent pumping, flue gas blowers and CO₂ compression, are required to run the MEA capture process. In this study a standard value of 150 kWh per tonne of CO₂ captured is estimated to be required for the electrical energy input.

2.3.2 Aqueous ammonia post-combustion capture system (DTE)

As shown in Figure 2-3 a similar flow diagram is used for post-combustion capture using aqueous ammonia solutions but, because of the volatility of the ammonia, a condenser must be provided inside the stripper. The lean solution from the stripper is cooled by the rich solution and further in an externally cooled heat exchanger in order to reach the defined absorber inlet temperature. In addition, because of the volatility of ammonia, the N_2 leaving the absorption column and the CO_2 leaving the desorption column will contain some NH_3 . Additional water washing columns are used to absorb this NH_3 .

The CO_2 absorber for ammonia capture is similar to SO_2 absorbers (i.e. flue gas desulphurisation plants - FGD) and is designed to operate with a slurry feed. The flue gas flows upwards in counter current to the slurry containing a mix of dissolved and suspended ammonium carbonate and ammonium bicarbonate; 90% of the CO_2 from the flue gas is captured in the absorber. The CO_2 rich slurry from the absorber contains mainly ammonium bicarbonate as the dispersed solids, which dissolves as the temperature increases in the heat exchanger to about $80^\circ C$ before it enters the stripper.

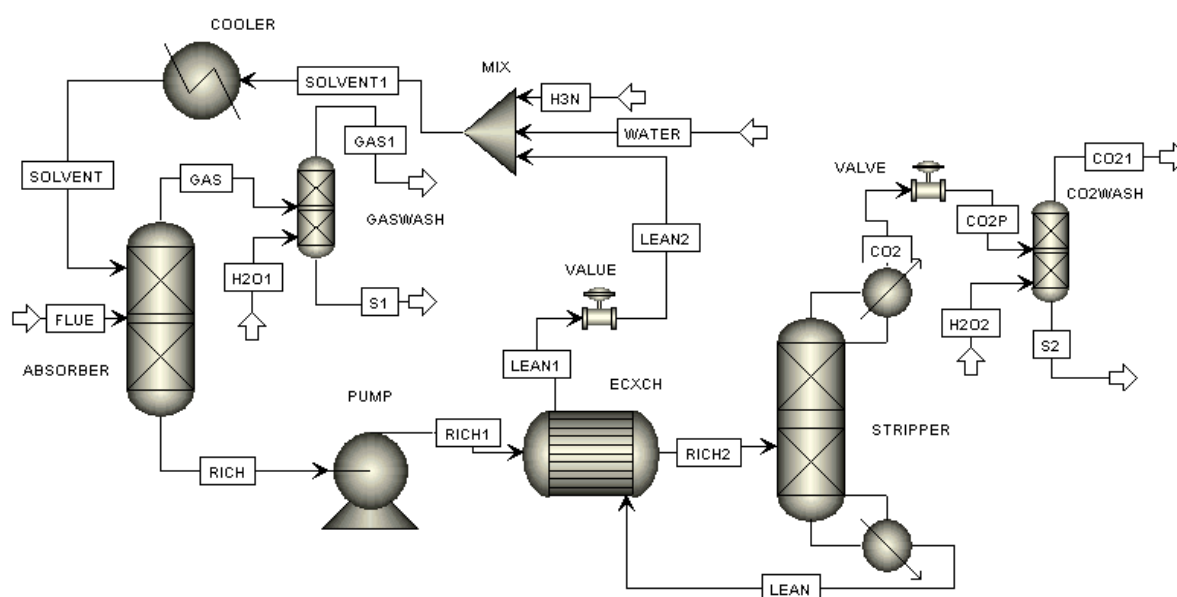


Figure 2-3 Process flow diagram for aqueous ammonia capture

2.3.3 Thermal integration between the power plant steam cycle and post-combustion capture units and calculation of overall plant efficiency and cost with capture (DCE, DTE, IMP, NCEPU, ZJU)

Effective integration between the base power plant and the post combustion capture equipment is essential to keep the efficiency penalty to a minimum. As shown in Figure 2-4, low-pressure steam for solvent regeneration is extracted from the crossover pipe between the intermediate pressure (IP) and low pressure (LP) turbine cylinders and heat recovered from the capture plant (principally from initial CO₂ cooling) and from the CO₂ compressor intercoolers is recovered and used for condensate heat (avoiding the need to extract steam from the LP turbine).

The steam turbines have been designed with an intermediate pressure (IP) turbine capable of operating with a floating outlet pressure, a design that (with slightly different modifications) is suitable for both capture ready steam plants and new build power plants that are capable of flexible operation. A floating IP turbine has the advantage of avoiding the throttling losses of a controlled extraction system with a valve at the LP turbine when the plant is operating with capture while not affecting the plant efficiency without capture. The IP turbine outlet pressure is higher than the operating pressure of the solvent reboiler when the plant does not capture CO₂. When CO₂ is captured steam is extracted and sent to the solvent reboiler the IP outlet pressure drops to the pressure required to feed the solvent reboiler.

LP steam extraction for feed water heating is reduced to 10% of the non-capture value by heating boiler condensate using heat recovered from cooling the CO₂ after the stripper and compressor stages. Calculated power plant performance without and with CO₂ capture is shown in Table 2-1 below.

To calculate the performance of the new build post-combustion capture cases the base case advanced supercritical plant was assumed to be modified slightly to operate with the steam cycle shown in Figure 2-4. When the steam required for operating the CO₂ capture plants, determined by modelling the capture systems described in 2.3.1 and 2.3.2 (and in more detail in DCE and DTE case study reports) is extracted from the steam cycle, and also taking into account the heat recovery from the capture and compression processes for condensate heating, the power output (calculated using gPROMS models as described in the Imperial report), falls to the values shown in Table 2-1 below. Additional electrical power to run the capture plant's fans and pumps and the CO₂ compressors, calculated from the specific values per tonne of CO₂ captured found in the case studies, has also to

be subtracted to give the reduced capture plant net outputs and net efficiencies shown in Table 2-1 below.

Table 2-1 Performance of new build advanced supercritical power plant without/with post combustion CO₂ capture and principal energy requirement assumptions

Solvent	MEA	NH ₃
WITHOUT CAPTURE		
Net plant power output (MWe)	824.3	824.3
Efficiency (%LHV net)	43.9	43.9
IP turbine outlet pressure (bara)	9.34	25.53
WITH CAPTURE		
IP turbine outlet pressure (bara)	4.17	12.57
Solvent reboiler steam pressure (bara)	3.67	12.06
Heat for solvent regeneration (MJ/kgCO ₂)	3.54	3.23
Turbine output power loss (MWe)	116.0	129.1
Capture and compression electricity requirements (kWh/tCO ₂)	150	43.4
Capture/compression plant power consumption (MWe)	86.1	25.0
Net plant power output (MWe)	621.5	670.3
Efficiency (%LHV net)	33.1	35.7

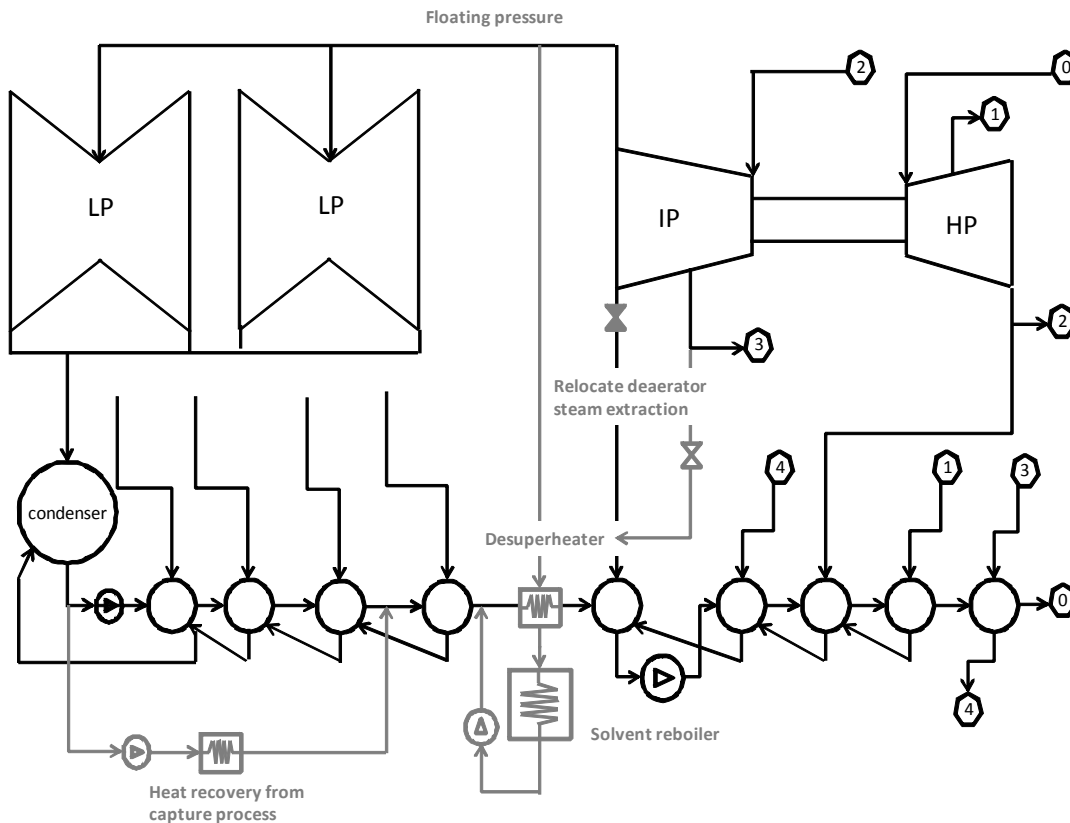


Figure 2-4 Steam turbine/capture plant integration with a floating intermediate pressure turbine

The main additional assumptions and estimating procedures for post-combustion capture plant capital costs are shown in the summary of technical and economic performance in Appendix B. The assumed additional charges for the capture and compression equipment and the, relatively minor, modifications to the base plant are based on the NCEPU case study results. A conservative assumption has been made that these capture and compression equipment costs (expressed as RMB/kW thermal) will be the same irrespective of the base plant size (across the range covered in WP3), because of uncertainties regarding the actual size of the individual absorbers and strippers that could be used (currently considered to be limited to 300-400 MW electrical output equivalent). If larger capture equipment unit sizes prove to be feasible in the future then some consequent economies of scale would be expected, although the effect on overall plant costs would be limited since the capture equipment itself is estimated to be only 20-25% of the total power plant capital cost with CO₂ capture.

3. Post-combustion capture from existing Chinese power plants (NCEPU)

In order to evaluate the impact of CO₂ capture on existing pulverised coal fired Chinese power stations, the cost and performance of 600MWe supercritical and 300MWe sub-critical PC power plants with 90% CO₂ capture and compression using MEA and aqueous ammonia were also estimated².

3.1 Chinese 600MW supercritical unit

The example plant used as a reference 600MW supercritical unit for this case study was No. 1 unit of GuiGang power plant, located at Guangxi, PR China. The steam generator in these plants is a tangentially coal-fired, supercritical pressure, controlled circulation, and radiant reheat wall unit, designed to generate about 1677.5t/h of steam at nominal conditions of 24.2MPa and 566°C with reheat steam heated to 566°C. The unit is configured in a conventional type design and is representative in many ways of a large number of coal-fired units in use throughout both China and worldwide today.

3.2 Chinese 300MW sub-critical unit

No. 2 unit of Daqi power plant was used as a reference 300MW subcritical unit. The Daqi pulverised coal power plant is located in Neimenggu province, PR China. The unit is designed to generate about 935t/h of steam at nominal conditions of 16.7MPa and 537°C with reheat steam heated to 537°C.

3.3 Performance without and with CO₂ capture

MEA and aqueous ammonia technology identical to that used for new build capture cases was assumed to be retrofitted to the existing plants. Calculated performance without and with CO₂ capture is shown in Table 3-1. The capture efficiency penalty for the 600MW supercritical plant is estimated to be slightly higher than that for the 300MW subcritical power plant with a similar CO₂ capture process. Compared to 300MW sub-critical units the 600MW supercritical units have higher steam temperatures and pressures and hence a smaller steam flow rate per MW generated. When the CO₂ capture process is retrofitted the decrease in steam flow will therefore be relatively larger for the supercritical plant, resulting in worse operating conditions in the low-pressure cylinder of the steam turbine.

² A more specialised case, in which an existing sub-critical power plant is rebuilt to use advanced supercritical steam conditions and also converted to oxyfiring capture at the same time, is described in the Doosan Babcock oxyfiring case study report.

Table 3-1 Estimated performance for existing PC plants with 90% CO₂ capture

	600MW no capture	600MW MEA capture	600MW ammonia capture	300MW no capture	300MW MEA capture	300MW ammonia capture
Net output, MWe	574.09	398.01	435.61	295.13	202.42	225.23
Net Plant LHV Efficiency (%)	40.28	27.93	30.56	38.15	26.17	29.12
Efficiency penalty (%-points)	—	12.35	9.72	—	11.98	9.03

4. Electric power generation with pre-combustion CO₂ capture (GG, THCEC)

4.1 Background

Pre-combustion capture technology is based on coal gasification and may be implemented as an Integrated Gasifier Combined Cycle (IGCC) plant for electricity production only or as a poly-generation system (for example, hydrogen-electricity coproduction, methanol-electricity coproduction). In all such systems, the coal will first react with oxygen to generate syngas which mainly consists of CO and H₂, and then the CO in the syngas will be converted into CO₂ and H₂ in a shift reactor. The mixture of CO₂ and H₂ is relatively easy to separate because it is at high pressure. Pre-combustion capture technology has the merit of imposing a lower energy penalty and capital cost increase than post-combustion capture when capture is implemented, but does require a gasifier-based power plant, which currently, for pure power generation, is more expensive than a pulverised coal power plant in China.

In recent years China has built many coal gasification projects, mainly for coal to oil, coal to chemical and poly-generation conversion plants. According to a recent THCEC study, there are approaching 100 large scale gasifiers currently in operation in China. Most of these are licensed Shell or GE gasifiers, but 4 units are domestically-designed slurry feed gasifiers. In 2005, China built a methanol-electricity polygeneration system in Shandong province. The polygeneration project produces 240,000 tonnes/yr methanol and 60MW electricity and has been supported by a MOST '863' program for demonstrating domestic slurry gasifiers. IGCC and pre-combustion CO₂ capture technology (based on IGCC) are now under development in China. In 2004, China Huaneng Group (CHNG) announced the "GreenGen project" and founded the GreenGen Company with seven other of the largest energy companies in China. GreenGen's goal is to develop and demonstrate an

IGCC+CCS project in China as one of the key technology options for China's electricity industry to use to tackle climate change. Now there are more than 10 IGCC power plants proposed in China, including Tianjin IGCC demonstration power plant, which is owned by the GreenGen Company and received approval from NDRC in May, 2009. As China's first IGCC plant, it will start operation in 2011 and will be the basis for a future IGCC+CCS demonstration project in China.

In Work Package 3 two pre-combustion CO₂ capture cases have been studied in detail, an IGCC with CCS system using a dry feed Chinese gasifier design and a chemical-electricity polygeneration plant with CCS using a slurry feed Chinese gasifier design. Parallel feasibility studies confirmed that Shell gasifier technology could also be applied satisfactorily to the coals being used.

Table 2-1 Pre-combustion Capture Case Studies

Case	GS1	GS2
Configurations	2×400MW IGCC+CCS	400MW IGCC+0.3Mt/yr methanol
Gasification	2×TPRI	3×Multi-nozzle
Gas turbine	2×9FA	1×9FA
ASU	Low pressure	Low pressure
Chemical product	---	Methanol
Shift	Two stage	Optimised for MeOH
CO ₂ Separation	Selexol	Rectisol
CO ₂ Removal efficiency	90% (overall for power plant)	86.4% (of CO ₂ at separation point)

4.2 GS1- 2×400 MW IGCC using TPRI gasifier with CCS (GG)

The flow diagram of the IGCC+CCS plant is shown in Figure 4-1. The IGCC+CCS system consists of a coal drying and milling sub-system, gasification subsystem, cleanup subsystem, water gas shift(WGS), CO₂ capture system, air separation unit (ASU), gas turbine (GT), heat recovery steam generator (HRSG) and steam turbine(ST).

The dry coal powder is transported into the gasifier by nitrogen from the ASU. Oxygen from the ASU and steam from the HRSG will also be injected into the gasifier where they will react with the coal powder. Slag produced in the gasifier falls down into the slag removal system and can be used as construction material. Raw syngas is quenched with dust-free cold syngas and enters the syngas cooler (SGC). In the SGC, the syngas is cooled down through two heat exchangers which can produce saturated steam at two pressure levels (high pressure and medium pressure). The saturated steam generated in the SGC will be sent to the steam cycle system of the power island. The cooled syngas is then dedusted in the dry solid removal system (DSR) and split into two sub-streams. One part is recycled for the syngas quench, the other is sent to the wet scrubbing system which removes hydrochloric and hydrofluoric acids. The reaction to convert CO to CO₂ happens in the water-gas-shift (WGS) unit. The outlet stream components of the WGS reactor are mainly CO₂ and H₂. Then the gas enters the sulphur removal unit and CO₂ capture unit. Separated CO₂ is compressed and dried. The remaining H₂-rich gas, diluted with N₂ from the ASU, enters the gas turbines with compressed air from the GT compressor to generate electric power.

The O₂ from the independent ASU is fed to the gasifier. Some N₂ from the ASU is used for coal feeding, but the bulk of the N₂ is injected into the GT combustor to control NO_x emissions. Hot flue gas from the gas turbine passes through the heat recovery steam generator (HRSG). The HRSG has sections to raise steam at three pressures (HP/IP/LP) and for reheating. Produced steam is sent to the steam turbine. Both the steam turbine and the gas turbine generate electric power.

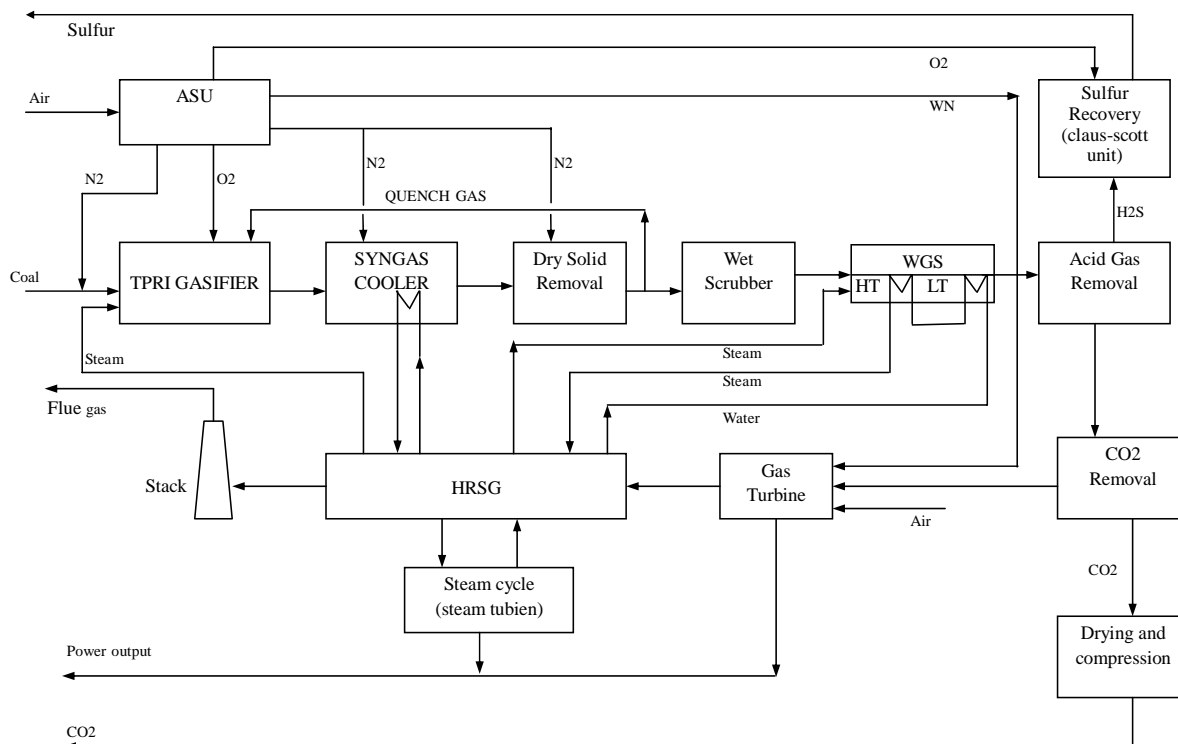


Figure 4-1 Diagram of Case GS1 IGCC+CCS System

The 2×400MW IGCC plus CCS plant has a gross output of 866.6 MW, lower than the IGCC base case without CO₂ capture (946.2 MW) because a large quantity of the steam is used in the shift reaction instead of generating electricity in the steam turbine. After subtracting power use within the plant to run the ASU, CO₂ compressor and other equipment 661.7 MW is available to supply, with a net efficiency of 36.8%. The Total Installed Cost for the IGCC+CCS plant is 8589 RMB/kW.

4.3 GS2- 1×400 MW polygeneration system with CCS (THCEC)

The polygeneration system is a series system, i.e. chemical and power are generated sequentially. The flowsheet for case GS2 is shown in Figure 4-2. First water and coal will be mixed to produce a coal-water slurry. The coal-water slurry is then pumped into the gasifier, where it reacts with oxygen from the ASU and injected steam. The amount of oxygen injected into the gasifier will be controlled carefully, in order to avoid generating molten slag in the first stage of the gasifier and to form molten slag in the second stage. Slag produced in the gasifier falls into the slag removal system and can be used as a good-quality construction material. Raw syngas produced in the gasifier is quenched with steam. The quenched syngas is then dedusted and cleaned up to remove hydrochloric and hydrofluoric acids in the scrubber. One part of the cleaned syngas is sent to the water-gas shift, where almost all CO in the syngas will react with steam and change into CO₂, then mixed with the other part of syngas. The ratio of shifted syngas will be used to control the ratio

between CO and H₂ in the mixed syngas to the desired value for methanol production. Before entering the Rectisol unit (which uses methanol produced in the plant), the syngas will be cooled down to about 40°C by exchanging heat with water, because the Rectisol unit works at low temperatures. In the Rectisol unit, H₂S and CO₂ will be selectively absorbed by the methanol solvent, and subsequently released by heating the solvent. H₂S will be sent to a sulphur recovery unit to produce elemental sulphur, and CO₂ will be compressed for transport and sequestration (110 bar assumed). The syngas leaving the Rectisol unit enters the methanol reactor containing a synthesis catalyst. The tail gas is burnt with air in a gas turbine to generate power. The hot flue gas leaving the gas turbine then passes through the Heat Recovery Steam Generator (HRSG). The HRSG is composed of several heat exchangers which can produce steam in a two pressure reheat steam cycle (HP/LP). The steam is sent to the steam turbine. Electricity produced by the steam turbine and gas turbine will be sent to the grid network and supplied to electricity consumers. The low-temperature flue gas is released through the stack.

The GS2 polygeneration case has a gross output of 525.8MWe + 0.32 Mt/year methanol, and the net output is 397.2MWe + 0.3 Mt/year methanol. The consumed electricity is used for running the plant facilities, such as the ASU, CO₂ compressor, pump, fan, etc. and some of the methanol is consumed as the Rectisol CO₂ absorption solvent. The output of sulphur, a by-product of polygeneration, is about 13855 t/year. The CO₂ emission of this polygeneration configuration is 196 kg/MWh of electricity, assuming that none of the CO₂ emissions are assigned to the methanol production. A consistent treatment of the benefits of producing this coal-derived methanol also with lower production CO₂ emissions would require a wider understanding of how the methanol was used, however, and is beyond the scope of this study.

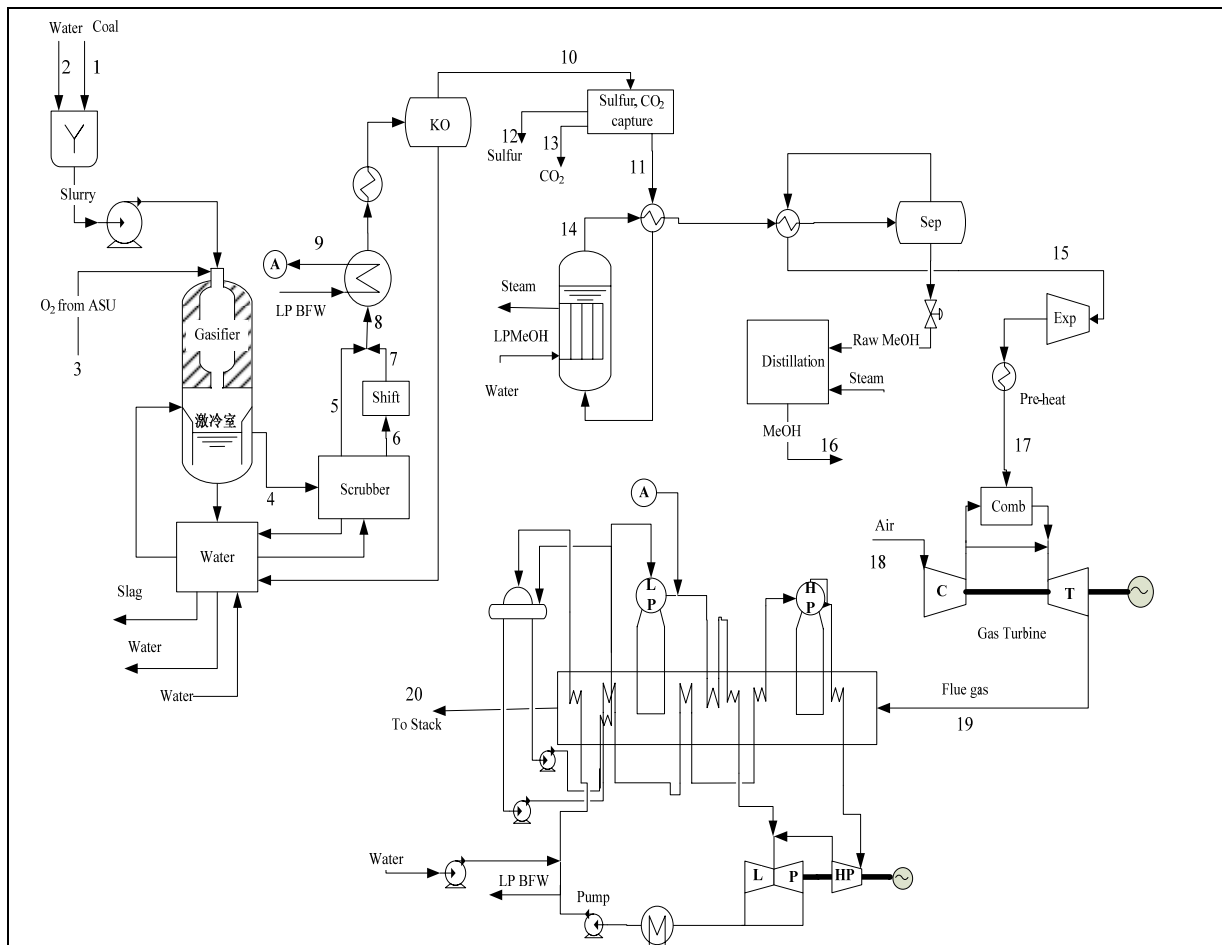


Figure 4-2 Block flow diagram of GS2 polygeneration plant

5. Summary of CO₂ capture performance for different plant types

Figure 5-1 summarises the calculated technical and economic performance of a range of coal fired power plant types with CO₂ capture under Chinese conditions. A coal cost of 16 RMB/GJ and a discount rate of 10% over a plant life of 25 years are assumed. The load factor is taken as 85% (67.5% in first, commissioning, year). Costs do not include financing costs and taxes. Other case study parameters are tabulated in Appendix A and numerical values for the capture performance are presented in Appendix B. The costs of CO₂ transport to the storage site and storage and monitoring are not included, but calculated costs for pipeline transport, from WHU, are presented in Appendix D.

Advanced new build capture technologies that have still to be demonstrated, oxyfiring, post-combustion with aqueous ammonia and pre-combustion capture on IGCC, are predicted to achieve similar efficiencies of 35.6, 35.7 and 36.8% respectively. CAPEX values for these plants are approximately 9000 to 10000 RMB/kW net, with an estimated +/- 30% uncertainty. Levelised costs

of electricity for these options are estimated to have a range of approximately 370-410 RMB/MWh. Costs of abatement are calculated relative to the standard alternative plant that would be built, an advanced supercritical plant. Since the cost of abatement is based on the differences between relatively larger numbers there is more variance in the results, from an estimated 140 RMB/tCO₂ for oxyfiring to 200 RMB/tCO₂ for IGCC+CCS. These values are, however, very sensitive to estimates for capture plant costs, particularly the additional capital costs, and should be regarded as preliminary.

Aqueous ammonia post-combustion capture is predicted also to work well retrofitted to existing plant. Absolute efficiencies are lower, due to a combination of the lower efficiency of the base plant and higher penalties due to less effective integration, but calculated costs of abatement, at around 200 RMB/tCO₂, would still be competitive with other capture options studied.

Post-combustion capture with an MEA-based solvent, a long-established technology which has been demonstrated at reasonable scale for industrial CO₂ separation applications although not yet for full-scale capture on power plants, is predicted to have a generally less favourable performance, with slightly lower overall capture plant efficiency and higher capital, electricity and abatement costs. This is in line with general experience and explains why the development of alternative post-combustion capture solvents, such as aqueous ammonia but also including advanced amines and a range of other systems, is currently receiving widespread attention.

Polygeneration of electricity and methanol appears to have a low efficiency and high capital costs but this is because the methanol production is not taken into account. Similarly, the calculated cost of abatement is high for this polygeneration option but this does not take into account the advantages of producing coal-derived methanol also with lower production CO₂ emissions. A consistent treatment of these benefits would require a wider understanding of how the methanol was used, however, and is beyond the scope of this study.

The sensitivity of levelised electricity costs to variations from the base case parameters is shown in Fig. 5.2. Predicted electricity costs decrease by about 15% if the assumed discount rate is reduced from 10% to 5%, and increase by slightly more if it is increased from 10% to 15%, except for polygeneration which changes by about 25% because of its higher capital costs. A decrease or increase of 30% in assumed CAPEX gives a corresponding change in electricity cost of approximately 12%, except for polygeneration at 17%. A doubling of coal price, from an assumed 16 RMB/GJ to 32 RMB/GJ increases power plant generation costs by around 50% without capture and by 40% with

capture, while polygeneration electricity costs increase by 60%. An increase in the assumed selling price of methanol from 2000 RMB/tonne to 2500 RMB/tonne would reduce polygeneration electricity costs with capture by approximately 10% and bring them in line with those for other capture options for the base case values (at 16 RMB/GJ coal costs).

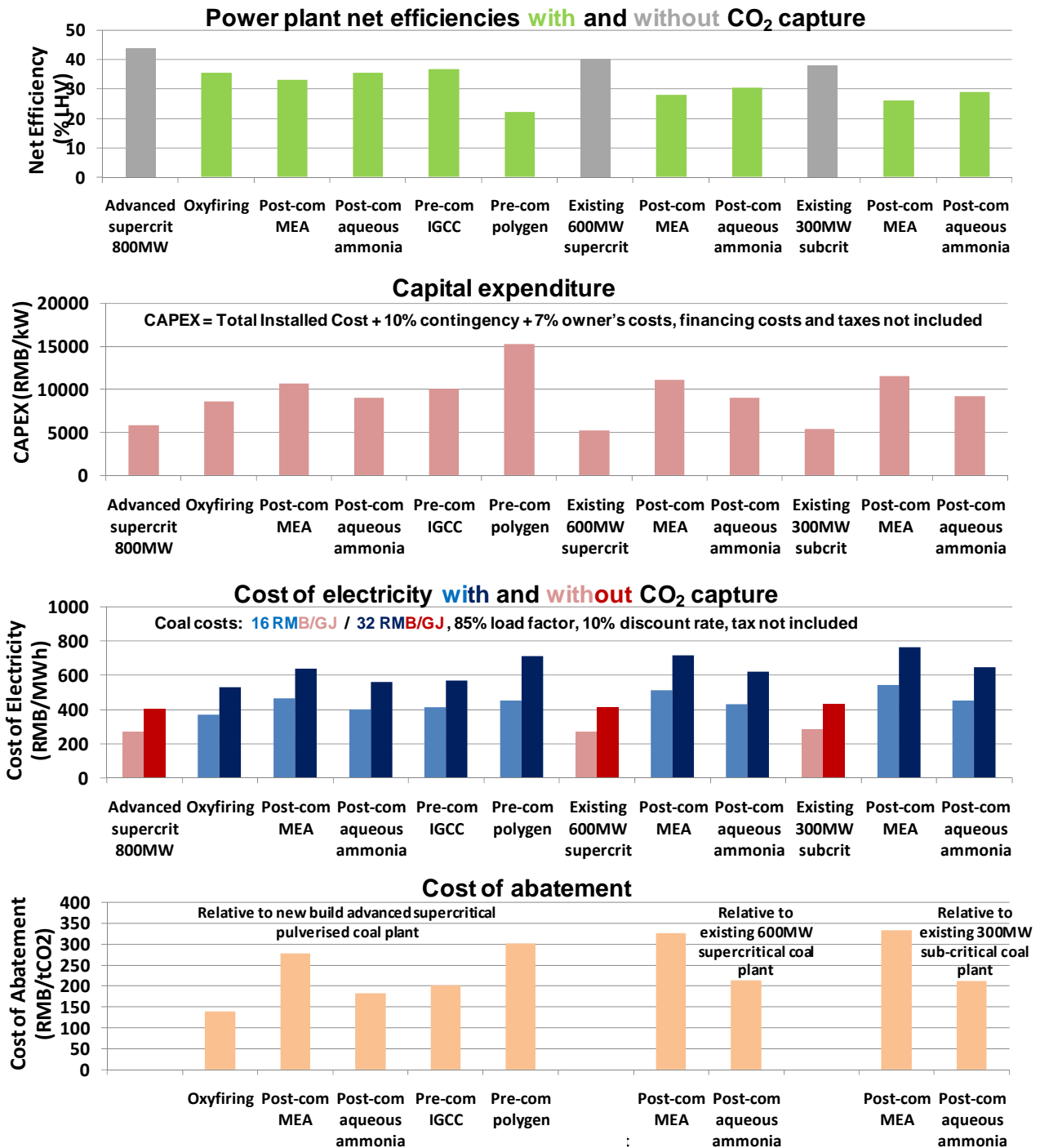


Figure 5-1 Summary of technical and economic performance of coal fired power plants with CO₂ capture under Chinese conditions

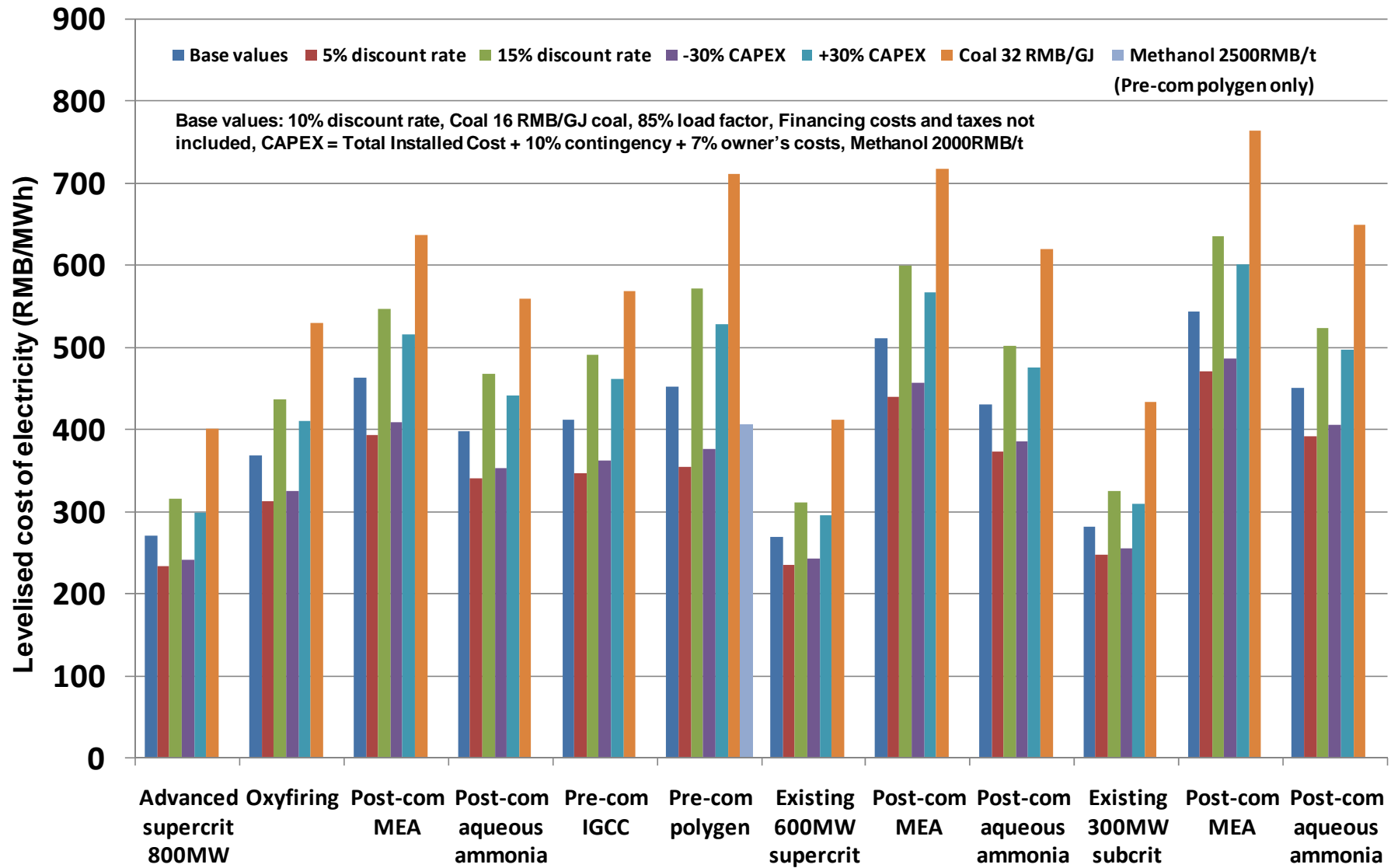


Figure 5-2 Sensitivity of levelised electricity costs to variations from base case parameters

Appendix A – Case study basis

The case studies were carried out using NZEC standard assessment criteria, which were consulted on by WP3 groups. The main criteria are:

- Plant location: Tianjin, PR China
- Shenhua bituminous coal as design coal, Datong coal as check coal
- Coal price 16RMB/GJ, LHV (low heat value) basis
- 63.75% load factor for the first operating year, and 85% load factor for other operating years
- 10% nominal discount rate (without considering inflation)
- 25 operating years
- Not considering other than local taxes.
- 90% CO₂ capture and compression to 110 bar

The ambient conditions, site characteristics and coal data are presented in the following tables.

Table A1 - Site Characteristics

Location	Tianjin, PR China
Topography	Level
Coal delivery	Unit train
Ash/Slag Disposal	Off site
Water Supply	River water
Access	Train and road

Table A2 - Site Ambient Conditions

Elevation (m)	5
Barometric Pressure (bar)	1.013
Average ambient temperature (°C)	15
Maximum ambient temperature (°C)	35
Minimum ambient temperature (°C)	0
Ambient Relatively Humidity (%)	60

Table A3 - Characteristics of Design Coals

Coal specification	Unit	Design coal	Check coal
		(Shenhua coal)	(Datong coal)
LHV	MJ/kg _{ar}	22.76	26.71
HHV	MJ/kg _{ar}	23.92	-
Ash content	A _{ar} (%)	11	9.98
Moisture content	M _{ar}	14	8.84
Ultimate analysis	C _{daf}	80.44	84.43
	H _{daf}	4.83	4.89
	O _{daf}	13.25	8.44
	N _{daf}	0.93	0.91
	S _{daf}	0.55	1.33
Ash characteristics	DT °C	1130	-
	ST °C	1160	-
	FT °C	1210	-

Appendix B – Tabulated summary of technical and economic performance of coal fired power plants with CO2 capture under Chinese conditions

Plant type		Advanced supercrit 800MW	Oxyfiring	Post-com MEA	Post-com aqueous ammonia	Pre-com IGCC	Pre-com polygen	Existing 600MW supercrit	Post-com MEA	Post-com aqueous ammonia	Existing 300MW subcrit	Post-com MEA	Post-com aqueous ammonia
Net output	MWe	824.3	672.5	621.5	670.3	661.7	398.2	574.1	398.1	435.6	295.1	202.5	225.3
Net efficiency	%LHV	43.9	35.6	33.1	35.7	36.8	22.3	40.28	27.93	30.56	38.15	26.17	29.12
Capture penalty	Percentage points	----	----	10.8	8.2	----	----	----	12.35	9.72	----	11.98	9.03
Plant thermal input	MWth	1878	1889	1878	1878	1799	1789.2	1425	1425	1425	774	774	774
Base Plant TIC	RMB/kW net	5000	----	5000	5000	----	----	4494	4494	4494	4574	4574	4574
Capture plant TIC	RMB/kW thermal	----	----	842	551	----	----	----	842	551	----	842	551
Base Plant TIC	MRMB	4122	----	4122	4122	----	----	2580	2580	2580	1350	1350	1350
Capture plant TIC	MRMB	----	----	1581	1035	----	----	----	1200	786	----	651	426
Overall plant TIC	MRMB	4122	4970	5702	5157	5683	5211	2580	3780	3366	1350	2001	1776
Overall plant TIC	RMB/kW net	5000	7390	9175	7693	8589	13088	4494	9495	7727	4574	9885	7886
Contingences	10% TIC	412	497	570	516	568	521	258	378	337	135	200	178
Owners cost (OC)	7% TIC	289	348	399	361	398	365	181	265	236	95	140	124
CAPEX	CAPEX=TIC+Contingences+OC	4822	5815	6672	6033	6649	6097	3019	4422	3938	1580	2342	2078
CAPEX - specific	RMB/kW net	5850	8646	10735	9000	10049	15313	5258	11110	9041	5352	11566	9226
Operating costs at 100% output													
Fuel	MRMB/yr	947.4	953.2	947.4	947.4	907.8	902.8	719.2	719.2	719.2	390.3	390.3	390.3
Maintenance (4% of TIC for PC options)	MRMB/yr	164.9	198.8	228.1	206.3	220.9	208.4	103.2	151.2	134.6	54.0	80.1	71.1
Chemicals and consumables	MRMB/yr	0	0	13.2	14.2	16.36	9.84	0	10.0	10.8	0	5.4	5.9
Capture solvent purchase and disposal	MRMB/yr	0	0	165.8	112.3	75.81	26.33	0	125.8	85.2	0	68.3	46.3
Insurance and land taxes (2% of TIC)	MRMB/yr	82.4	99.4	114.0	103.1	113.7	104.2	51.6	75.6	67.3	27.0	40.0	35.5
Waste disposal (MeOH sales@2000RMB/t)	MRMB/yr	0	0	0	0	0	-649.4	0	0	0	0	0	0
Operating labour + OHd +supervision	MRMB/yr	18.72	22.88	22.88	22.88	29.12	33.28	16.64	20.8	20.8	14.56	18.72	18.72
CO2 transport and storage costs	MRMB/yr		0.00	0.00	0.00	0.00	0.00		0.00	0.00		0.00	0.00
Number of operators		180	220	220	220	280	320	160	200	200	140	180	180
Levelised cost of electricity	RMB/MWh	271.3	368.9	463.2	398.3	412.5	453.0	270.1	512.4	431.9	283.1	545.2	451.7
CO2 emissions	g/kWh	796.6	98.2	105.6	98.0	95.44	196	868.2	125.2	114.4	916.6	133.6	120.1
CO2 captured (90% for PC)	g/kWh	----	884.1	950.8	881.6	859	1375.4	----	1126.9	1029.9	----	1202.6	1080.8
	Mt/yr at 85% load		4.4	4.4	4.4	4.2	4.1		3.3	3.3		1.8	1.8
Cost of CO2 abatement vs PC plant	RMB/tCO2		139.7	277.8	181.7	201.4	302.5		326.2	214.6		334.7	211.6
									vs 600MW supercrit	vs 600MW supercrit		vs 300MW subcrit	vs 300MW subcrit

Appendix C - CO₂ capture using membrane gas absorption technology (ZJU)

Unlike conventional chemical absorption technology, the membrane gas absorption technology studied by ZJU for NZEC uses amine solvents (MEA in this case) inside hydrophobic hollow fibre membrane contactors to absorb CO₂ i.e. it is based on a combination of membrane gas separation and chemical absorption technology. The basic principle of membrane gas absorption technology is shown schematically in Fig. C-1. Unlike gas membrane separation processes (i.e., without using solvents) which depends on the membrane selectivity, the hollow fibres adopted in the membrane contactor, which have many micropores in their walls (as shown in Fig. C-2) are generally not selective. The selectivity to CO₂ is implemented by the alkaline solution inside the tubes, which means that the driving force for CO₂ absorption is based on the CO₂ concentration gradient between the lumen side and shell side of membrane.

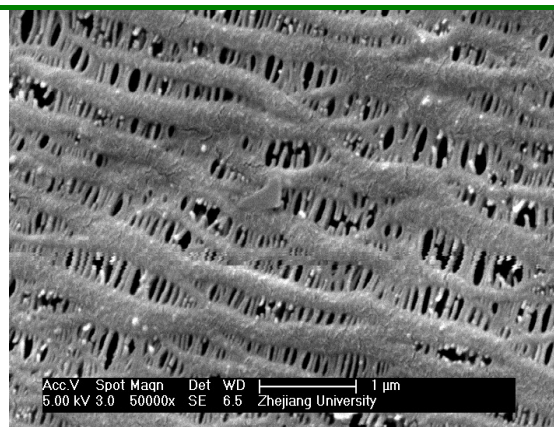
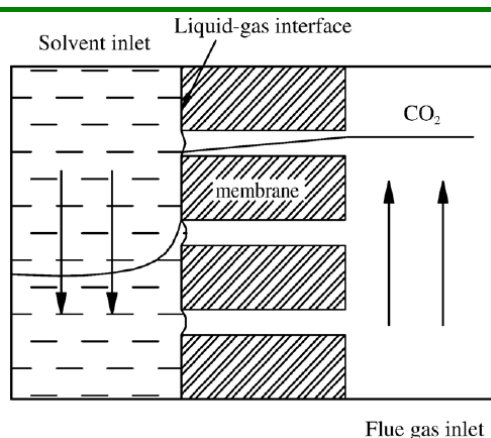


Fig. C-1. Principle of membrane gas absorption.

Fig. C-2. Micropores in the membrane wall.

A typical membrane contactor is shown in Fig. C-3. In the hollow fibre membrane contactor, hydrophobic microporous membranes are used to form a permeable barrier between the liquid phase and gas phase, which permits mass transfer between the two phases without dispersing one phase into another. In general, the gas and liquid phases always flow in parallel (either countercurrently or concurrently) to each other on the opposite side of the fibres, and the gas preferentially fills the hydrophobic membrane pores and meets the liquid at the opposite side of membrane. In this study, polypropylene (PP) membrane contactors were selected to act as the absorber in the membrane gas absorption technology because of their lower price and commercial availability. The inner diameter (I.D.) of the PP fibre is about 30 μm, the outer diameter (O.D.) of fibre is about 40 μm and the porosity of the fibre is about 50%.

In order to prevent membrane wetting problems it is preferable to decrease the MEA concentration. But lower MEA concentrations will lead to an increase in the flow rate of the solvent and

consequently an increase in regeneration energy consumption. So 20%w/w MEA solution was selected in this case, as a compromise between relatively higher surface tension and relatively lower solvent flow rate. The calculated thermal energy consumption for solvent regeneration under these conditions was 3.98 GJ/tCO₂. This was significantly higher than for the 30%w/w MEA solution used in a conventional absorber, which was estimated to require 3.54 GJ/tCO₂ (DCE), and estimated capture plant capital costs were not significantly different. So a membrane gas absorption option was not included in detailed techno-economic comparisons.

If further development work was able to lead to increased solvent loading and/or significantly reduced capital costs then the operational advantages of membrane contactors could make them of interest. Since the gas and liquid phases flow on the opposite sides (i.e., shell and lumen sides) of the hollow fibres they can be controlled independently. This is especially effective in avoiding problems such as flooding, foaming, channelling and entrainment, which can be encountered in packed or tray towers.

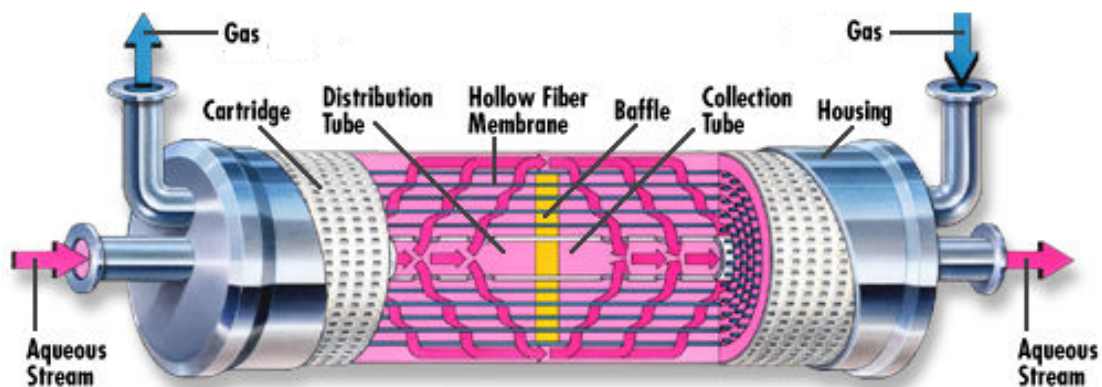


Fig. 3-3 Typical structure of hollow fiber membrane contactor

Appendix D - Levelised cost of transporting CO₂ as a function of mass flow rate

The following costs for dense phase supercritical CO₂ transport by pipeline in China are taken from the report from Wuhan University (WHU). They are based on continuous utilisation of the pipeline (i.e. 365 days/year). For lower utilisation rates the costs can be adjusted reasonably accurately by dividing by the utilisation factor.

CO ₂ Mass Flowrate (tonnes/day)	Cost (CNY/tCO ₂) vs Transport Distance – L (km)				
	L=50	L=100	L=200	L=300	L=500
2000	16.15	35.34	77.35	128.14	225.02
4000	10.29	22.52	49.29	81.19	143.42
6000	7.91	17.30	37.87	62.28	110.40
8000	6.56	14.35	31.41	51.63	91.78
10000	5.67	12.42	27.17	44.67	79.58
12000	5.04	11.03	24.14	39.70	70.85
14000	4.56	9.98	21.83	35.93	64.25
16000	4.18	9.15	20.02	32.97	59.04
18000	3.87	8.47	18.54	30.57	54.82
20000	3.62	7.91	17.32	28.57	51.30