LEADING OPTIONS FOR THE CAPTURE OF CO_2 EMISSIONS AT POWER STATIONS

Report Number PH3/14
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Title: **Leading options for the capture of CO_2 emissions at power stations**
Reference number: **PH3/14**
Date issued: **February 2000**

Other remarks:

Background to the study

The processes assessed in this study are generally regarded as the methods most likely to be used today, if deep reductions in CO_2 emissions are required in power generation. These processes have been examined previously by IEAGHG but, in recent years, there has been considerable improvement in the cost and efficiency of large-scale power generation technology. Some progress has also been made in the development of technologies for capture of CO_2. There is, therefore, a need to re-assess these leading technology options because they are widely used as references against which to calibrate more speculative mitigation options.

IEA GHG has established a set of standard assessment conventions that it uses as the basis for all its evaluations; a secondary purpose of this study was to incorporate revised conditions in the assessments, thereby providing a updated set of base-cases for future comparison of other options.[1]

Approach adopted

The processes considered are based on the main fossil fuels used for power generation, i.e. natural gas and coal. Other fossil fuels are not examined here but emissions and approximate costs can be inferred from the two fuels considered.

The assessments are for new power stations built on green-field sites.

Reference cases are needed against which to calculate the penalties incurred for CO_2 abatement. In the case of natural gas the reference case is a natural gas combined cycle (NGCC). For coal, two reference cases are assessed: (i) a power station with a feed of pulverised fuel in which electricity is generated by a steam turbine operating in a supercritical steam cycle (supercritical p/f) (ii) an integrated gasification combined cycle (IGCC).

The approaches to CO_2 capture assessed in this study are based on the application of existing technology for CO_2 capture to state-of-the-art power generation technology. However, the CO_2 capture technology has not, for any of the processing schemes examined, been demonstrated integrated into the production of electricity at a commercial scale.

State-of-the-art technology for construction starting in year 2000 has been assumed. This defines important criteria such as the efficiency of gas turbines and properties of advanced steam cycles. The cost assumptions are also based on the state-of-the-art for construction in year 2000. These state-of-the-art assumptions can represent markedly different stages in the technical development of particular processes - they range from well-established, through first generation commercial, to demonstration, or even merely conceptual.

[1] The most significant change is a reduction in the price assumed for fossil fuels (see later).

The assessments are based on a standard set of criteria developed for IEA GHG studies. The criteria are intentionally simple so that members can adapt the results for their own circumstances (e.g. dearer fuel, different capital charge rates, etc.). They are believed to be adequate for feasibility studies and for the calibration of leading CO_2 abatement options as reported here. All efficiencies quoted refer to the lower heating value (LHV).

The cost of CO_2 storage is not considered in this report, but the cost of preparing CO_2 for export by raising the pressure to 110bar is included in the assessment.

The study was done by Stork Engineering Consultancy, Amsterdam, The Netherlands.

Results and discussion

Eight power generation processes are assessed in the study, 5 of which are processes in which CO_2 is captured and 3 are reference cases. A brief outline of each process follows. In the processes that use oxygen it is obtained from an air separation unit (ASU). The processes are described in detail in a series of appendices to the main report.

the processes:
NGCC (reference). This process is a conventional natural gas-fired combined cycle, the main components of the process are as depicted in figure S1 below. The assessment is based on a state-of-the-art gas turbine (GE frame 9FA) with a dry low NO_x combustion system. Steam is raised from the gas turbine's exhaust gas in a heat recovery steam generator (HRSG). Approximately 2/3 of the power is produced in the gas turbine and 1/3 in the steam turbine.

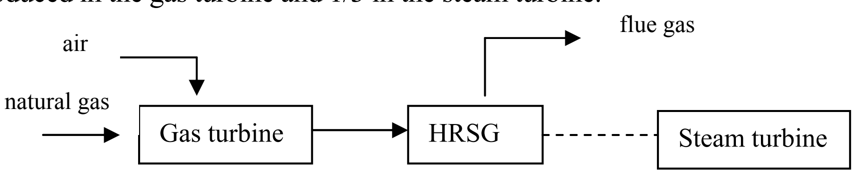

Figure S1: NGCC process

NGCC + CO_2 capture. In this process the flue gas from a conventional NGCC is treated in an absorber to capture CO_2. The main components of the process are as depicted in figure S2 below. The solvent is monethanolamine (MEA). Compared to the NGCC process the turbine steam turbine loses about 1/3 of its output because steam is required to recover CO_2 from the solvent.

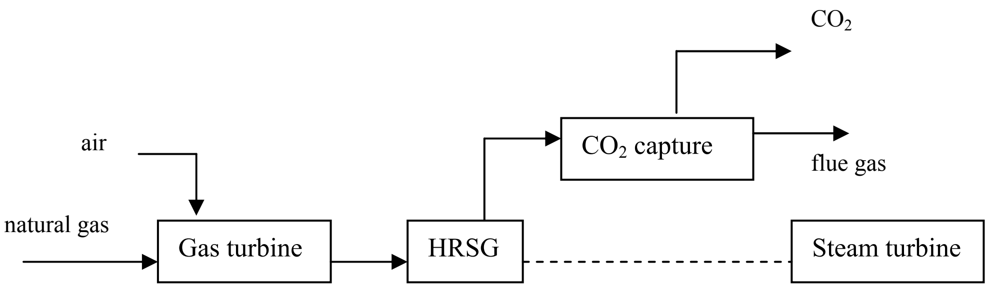

Figure S2: NGCC + CO_2 capture

NGCC + CO_2 capture + CO_2 recycle. In this process, as in the process above, the flue gas from a NGCC is treated in an absorber to capture CO_2. In addition, half of the flue gas is recycled to the gas turbine; this reduces by 50% the volume of gas to be treated in the CO_2 absorber and has the effect of doubling the concentration of CO_2 (from about 4 % to about 8% by volume). The quantity of recycle is the maximum believed to be acceptable in an existing turbine. The main components of the process are as depicted in figure S3 below.

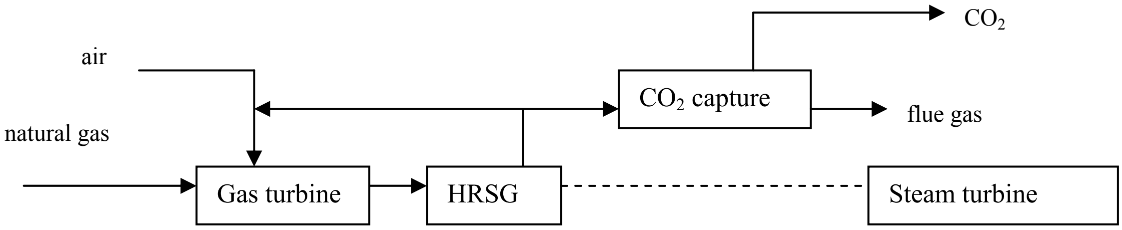

Figure S3: NGCC + CO_2 capture + CO_2 recycle

POCC + CO_2 capture. In this partial oxidation combined cycle (POCC) natural gas is converted to a synthesis gas in an oxygen-blown autothermal reformer (see later). The synthesis gas is then shift converted to a mixture of hydrogen and CO_2. The CO_2 is captured in a physical solvent. The hydrogen-rich fuel gas is burnt in the gas turbine of a combined cycle to produce electricity. The process is the natural gas equivalent of the coal IGCC case (see fig S8). The main components of the process are as depicted in figure S4 below. (There is no equivalent process without CO_2 capture as electricity can be made directly from natural gas in a combined cycle without having to go through an intermediate step of synthesis gas production).

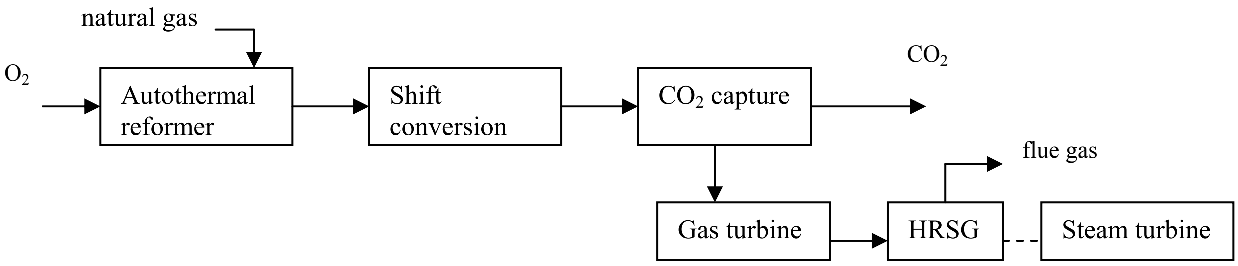

Figure S4: POCC + CO_2 capture

Supercritical p/f (reference). In this process pulverised coal is fired in a once-through boiler. Steam, raised in a double-reheat supercritical cycle (310bar/593°C/593°C/593°C), is used to generate electricity. The processing scheme includes SO_2 removal by wet scrubbing, and NO_x reduction by use of low-NO_x burners and selective catalytic reduction. The main components of the process are as depicted in figure S5 below.

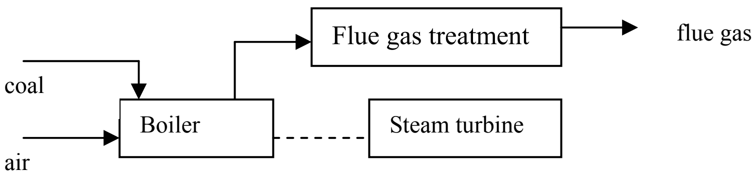

Figure S5: Supercritical p/f.

Supercritical p/f + CO_2 capture. In this process CO_2 is recovered from the flue gas using MEA solvent. The output of electricity is reduced considerably by the demand for steam to recover CO_2 and regenerate the solvent. The main components of the process are as depicted in figure S6 below.

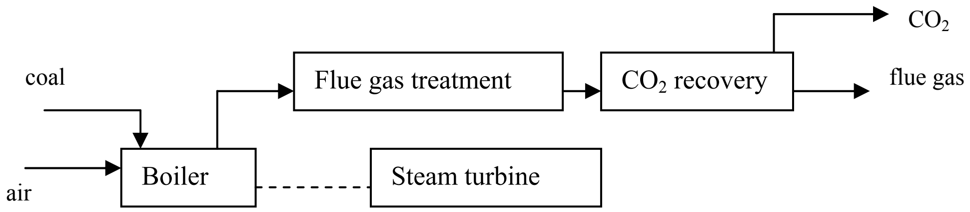

Figure S6: Supercritical p/f + CO_2 capture.

IGCC (reference). In this process electricity is produced from coal in an integrated gasification combined cycle (IGCC). The main components of the process are as depicted in figure S7 below. The O_2-blown gasifier is a dry feed unit based on Shell technology operating at 27bar and 1613°C. The synthesis gas is quenched before cleaning, to remove mainly sulphur compounds and particulates, before being fed to the combined cycle. The gas turbine is based on a suitably modified GE frame 9F.

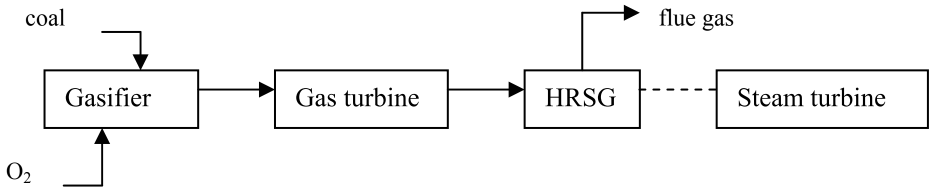

Figure S7: IGCC.

IGCC + CO_2 capture. In this case the above IGCC process is modified to include shift conversion of the synthesis gas and recovery of CO_2 in a physical solvent. The main components of the process are as depicted in figure S8 below. A hydrogen-rich fuel gas is burnt in the gas turbine (see later).

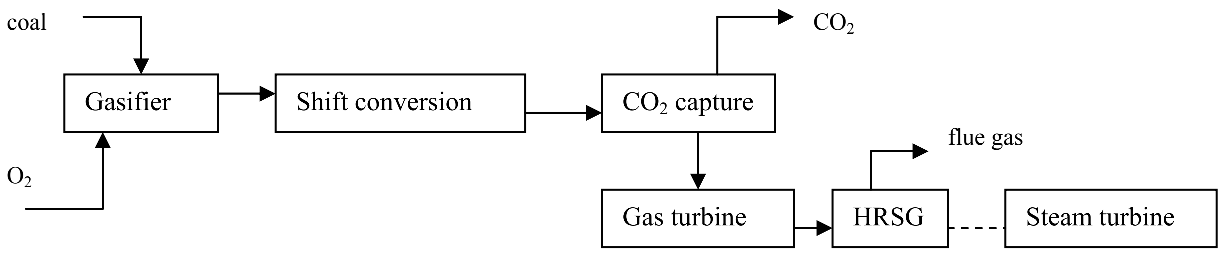

Figure S8: IGCC + CO_2 capture.

key results

The key results of the assessments are presented in tables S1 (natural gas) and S2 (coal) below. For natural gas, all 3 capture processes reduce emissions by over 80% at an electricity cost penalty of about 1cent/kWh (range 0.9-1.2 c/kWh). The cost of CO_2 capture ranges from about 30 to 40 \$/tCO_2 emission avoided (110-150 \$/tC). On the basis of these figures, within the accuracy of these assessments, there is little to chose between the 3 capture options but the POCC route is marginally more expensive.[2]

[2] Note that the air-blown version of the partial oxidation route (see report PH2/19) is not assessed here. A forthcoming report (PH3/21) assesses various partial oxidation options and will make comparisons with these results.

Table S1: Key results for natural gas cases (at 10% discount rate and a natural gas cost of 2\$/GJ)

Process	Efficiency % (LHV)	Specific Investment (\$/kWe)	Cost of electricity (c/kWh)	CO_2 emission (g/kWh)	Cost of CO_2 avoided in \$/tCO_2 (\$/tCO_2 captured)
NGCC (no CO_2 capture)	56	410	2.2	370	reference
NGCC + CO_2 capture	47	790	3.2	61	32 (27)
NGCC + CO_2 capture + CO_2 recycle	48	720	3.1	63	29 (25)
Partial oxidation CC + CO_2 capture	48	910	3.4	65	39 (33)

Two reference cases are used for the coal results (table S2). Supercritical p/f and IGCC technology are separately compared with and without CO_2 capture. In both cases use of CO_2 capture reduces emissions by about 80%. Adoption of CO_2 capture with IGCC technology incurs significantly less of a penalty (cost increase of 2.1 c/kWh, efficiency loss 8% points, cost of capture 37\$/tCO_2) than incorporating CO_2 capture in a supercritical p/f plant (cost increase of 2.7 c/kWh, efficiency loss 13% points, cost of capture 47\$/tCO_2).

The high penalties in the p/f +CO_2 capture case are primarily a consequence of lost power generation due to steam being taken from the turbine to recover CO_2 from the solvent. Roughly 90 MWe of power are lost (see tables in relevant appendices).[3] Note however, that although the penalties are greater the cost of electricity is still cheaper for the p/f-based system (6.4c/kWh as opposed to 6.9c/kWh).

Table S2: Key results for coal cases (at 10% discount rate and a coal cost of 1.5\$/GJ)

Process	Efficiency % (LHV)	Specific Investment (\$/kWe)	Cost of electricity (c/kWh)	CO_2 emission (g/kWh)	Cost of CO_2 avoided in \$/tCO_2 (\$/tCO_2 captured)
Supercritical p/f (no CO_2 capture)	46	1020	3.7	722	reference
Supercritical p/f + CO_2 capture	33	1860	6.4	148	47 (34)
IGCC (no CO_2 capture)	46	1470	4.8	710	reference
IGCC + CO_2 capture	38	2200	6.9	134	37 (31)

A comparison of the process streams containing CO_2 is presented in table S3. In the cases where CO_2 capture is used, the process stream concerned is the feed to the capture process; for the reference cases the process stream is the flue gas. It is notable that the wide range of CO_2 concentrations, flow rates, and pressures is not reflected in a wide range of penalties for CO_2 capture.

[3] In this study amine regeneration requires 5MJ/kg CO_2. Previous IEA GHG studies have used 4MJ/kgCO_2. A new solvent developed by Mitsubishi is claimed to have an energy requirement of about 3MJ/kg CO_2. The actual requirement may be proprietary knowledge; it depends on the temperature of steam required to regenerate the solvent. Typically this is in the range 120 to 150°C, the lower the better in terms of reducing power loss.

Table S3: A comparison of process streams containing CO_2.

Process	Process stream	mole % CO_2	kg/s	pressure (bar)	\$/t CO_2 avoided
NGCC (no CO_2 capture)	flue gas	4.1	1290	1.01	reference
NGCC + CO_2 capture	feed to capture	4.3	1250	1.01	32
NGCC + CO_2 capture + CO_2 recycle	feed to capture	9.0	605	1.01	29
POCC + CO_2 capture	feed from shift reactor to capture	24.4	110	20.0	39
Supercritical p/f (no CO_2 capture)	flue gas	13.8	490	1.0	reference
Supercritical p/f + CO_2 capture	feed to capture	14.6	470	1.05	47
IGCC (no CO_2 capture)	flue gas	8.7	640	1.01	reference
IGCC + CO_2 capture	feed from shift reactor to capture	36.2	95	20.0	37

state-of-the-art

All the required technology components of the processes assessed here exist in some large-scale processing application. NGCC and supercritical p/f are established technologies that are used commercially. In recent years, they have undergone considerable development leading to major cost reductions and efficiency gains. Despite considerable interest IGCC is not established as a fully commercial process for the production of power from coal. Demonstration plants have shown that the process can be operated reliably and efforts are being made to reduce the costs to a level at which IGCC would be competitive with p/f power generation. At present the development of gasifier technology is largely being driven by a need to process oil refinery residues. Partial oxidation of methane is widely used in the chemical industry as a source of synthesis gas (an intermediate in the production of hydrogen, ammonia, etc).

The technologies used to capture CO_2 are less well established than the technologies mentioned above. For example, amine solvents are in limited commercial use to capture CO_2 from flue gases but not as part of a power generation process.

The appendix to this overview gives a brief review of the technologies involved, focusing on their development status and the prospects for improvement.

reducing the penalties for CO_2 capture

It will always cost more to capture and store CO_2 than to release it to atmosphere. The overall abatement cost includes the cost of transport and storage; typically this would add the equivalent of <0.5c/kWh to the capture costs presented in this report. So capture is the main contribution to the cost of abatement. It can be argued that any cost above zero would be regarded as expensive but it is thought that reducing the cost penalty for capture would help lower the barrier against use of this technology.

Table S4 gives breakdowns of the cost of electricity for two of the comparisons made in the study. The total penalty for CO_2 capture is about 1c/kWh for natural gas systems and about 2c/kWh for coal systems. If major reductions in the cost of CO_2 capture are to be made, the capital cost of the equipment is the main place to look for reductions. Section 5 of the report examines the cost sensitivities, showing that the cost penalties for capture are dominated by the increase in capital charges. Even at a high fuel price (e.g. 3\$/GJ for coal which is twice the reference price) capital charges are still responsible for over 60% of the increased cost of electricity. Similar findings apply to CO_2 capture from natural gas. It follows that reducing the efficiency penalty by installing extensive (i.e. costly) energy recovery facilities is not likely to be the most effective way to make major reductions in the cost of CO_2 capture.

Table S4: Breakdown of electricity cost in cents/kWh (at a 10% discount rate)

Cost component	Natural gas			Coal		
	NGCC	NGCC + CO_2 capture	Capture penalty c/kWh (%)	IGCC	IGCC + CO_2 capture	Capture penalty
fuel	1.3	1.5	0.2 (20%)	1.2	1.4	0.2 (9%)
capital charges	0.7	1.3	0.6 (60%)	2.7	4.1	1.4 (67%)
other	0.2	0.4	0.2 (20%)	0.9	1.4	0.5 (24%)
total (c/kWh)	2.2	3.2	1.0 (100%)	4.8	6.9	2.1 (100)

Previous experience with technology development shows it is likely that the capital costs will be significantly reduced by embodiment of experience and learning. For example, when flue gas desulphurisation was first introduced the plant was costly and unreliable. Over the next 20 years, the cost decreased. Such improvements are due to a combination of learning and increased production volumes, which reduce unit manufacturing costs. Typically, a doubling of installed capacity is accompanied by a 20% reduction in the capital cost.

It was suggested at the recent Houston workshop[4] attended by many manufacturers and constructors that systems integration could result in major cost reductions. This cannot be addressed in the studies reported in this and similar assessments in which a selection of existing component technologies is assumed to be linked together. (The level of detail is such that very little can be done in these studies to integrate the process modules in an optimum manner. A detailed process design in which such process optimisation could be done would cost hundreds of thousands of dollars.)

At the same time it must be admitted that cost estimates made early in stages of development of a new technology are often low compared with the actual costs of the first commercial version of the technology. The fact that CO_2 capture is based on established technology gives us some confidence that this particular problem is not a serious danger here.

Table S5 gives a breakdown of the specific costs for the processes considered. It can be seen, for instance that CO_2 compression costs in the coal cases are roughly twice as great for the natural gas cases (there is roughly twice as much CO_2/kWh in the coal cases).

[4] CO_2 Capture and geologic sequestration, joint BP Amoco, FETC, and IEA GHG workshop, September 28-30th 1999, Houston, Texas, USA.

Table S5: Breakdown of specific costs ($/kWe) [5]

Process	power generation	CO_2 capture	CO_2 compression	total ($/kWe)
NGCC (no CO_2 capture)	410	-	-	410
NGCC + CO_2 capture	505	232	53	790
NGCC + CO_2 capture + CO_2 recycle	502	165	53	720
Partial oxidation CC + CO_2 capture	418	447[6]	45	910
Supercritical p/f (no CO_2 capture)	1020[7]	-	-	1020
Supercritical p/f + CO_2 capture	1439	307	114	1860
IGCC (no CO_2 capture)	1470[8]	-	-	1470
IGCC + CO_2 capture	1768	342	90	2200

There are opportunities to reduce the cost of processing equipment, for example:

- for amine solvent systems, the replacement of conventional random packing by 'high performance' structured packing could drastically reduce the size of the absorption column and associated equipment.
- if POCC can be successfully adopted with an air-blown reactor this would avoid the cost of an air separation unit.
- compared to natural gas, hydrogen combustion can develop about 4% more power from a given gas turbine.

A detailed assessment of the possibilities for cost reduction would probably reveal more potential areas for cost reduction but, ultimately, practical experience is needed to verify the estimates and to progressively reduce costs.

confidence

These results have the advantage of covering the leading options for CO_2 capture in one study, by one contractor, on a common basis. From the viewpoint of IEA GHG, and other potential users, this avoids the many difficulties encountered when trying to compare results from different sources which inevitably use different assessment criteria, make different cost assumptions, and are often written to promote a particular technology.

Confidence in the predicted performance of the processes assessed is very high in the case of the NGCC and the supercritical p/f power station because the results are based on existing plant. Confidence in the predicted performance of the IGCC is not as high although several demonstration plants have been built and many detailed design assessments made. For the processes in which CO_2 is captured, the main uncertainty is the extent to which integration (of the CO_2 capture process and the power generation plant) is likely to be effective.

[5] Cost of plant and equipment including construction, services, fees, contingencies, etc.
[6] Includes the ASU and gas conversion (partial oxidation/reforming and shift conversion)
[7] Includes 23$/kWe for the SCR unit.
[8] Includes 166$/kWe for the ASU.

Cost estimates add a further layer of uncertainty to the process issues. The capital cost estimates for commercialised technology (NGCC and supercritical p/f) are very good as they are based on existing plant; it must be recognised, however, that the 'cost' of a plant is very dependant on numerous circumstances e.g. the state of the equipment sales market. Cost estimates for processes that are not commercially established (IGCC – demonstration; CO_2 capture/POCC/CO_2 recycle – existing technology in a different application) are inevitably more speculative.

In previous assessments we have standardised on fuel prices of 2$/GJ for coal and 3$/GJ for natural gas. In this study the central estimates are based on reduced prices: 1.5$/GJ for coal and 2$/GJ for natural gas. The contractor suggests (appendix 12) that these fuel prices are low, saying that 3$/GJ would be more appropriate than 2$/GJ for natural gas and that 1.8$/GJ would be more appropriate than 1.5$/GJ for coal. We are of the opinion that the fuel prices used are about right for piped supply of natural gas and imported coal, possibly the coal price should be lower (not higher). Information is given in section 5 of the main report so that the user can select the fuel price they think appropriate.

Expert Group comments

A draft version of the report was circulated to the experts and few comments were received. There were various comments on details that have been dealt with in the final version of the report.

Major conclusions

The capture of CO_2 incurs a cost penalty of about 1c/kWh for natural gas fired power stations. For coal-fired power stations the penalty for CO_2 capture is about 2c/kWh.

The cost of CO_2 capture, including compression to 110bar for dispatch to storage, lies in the range 30-50$/t CO_2 avoided (110-170 $/tC) for all the processes assessed (compared with similar plant without capture).

In the case of natural gas there is little to chose between the capture options examined. The option of post-combustion scrubbing the flue gas using an amine-based solvent is marginally the cheapest.

In the case of coal, CO_2 capture in an IGCC process has a lower penalty than CO_2 capture by absorption from the flue gas of a supercritical p/f power station. However, because the IGCC process is expensive compared to p/f combustion, even with CO_2 capture the cost of electricity is cheaper from a supercritical p/f power station.

The cost per tonne of CO_2 emissions avoided (or captured) is similar for both natural gas and coal cases. This might seem counter-intuitive, as CO_2 streams are more concentrated in coal processes than in natural gas processes. However, much of the cost is directly related to the mass of CO_2 handled (e.g. amount of CO shift converted, energy required per unit mass of CO_2 recovered from the solvent, CO_2 compression for export to store).

Much of the cost penalty for CO_2 capture is due to capital charges. If the cost of CO_2 abatement is to be substantially reduced the installed cost of CO_2 capture equipment must be reduced. There are prospects for making significant capital cost reductions but, achieving such reductions will require a series of developments which allows economies of scale and the benefits of learning.

The above conclusions are not sensitive to changes in the standard assessment conditions. The most significant assumption is discount rate; if a 5% discount rate is used the cost penalty for CO_2 capture in IGCC plant is reduced to 1.6c/kWh. (The cost penalty is 2.1c/kWh at a 10% discount rate.)

Recommendations

It is recommended that the results of this study be used as reference costs for other studies of the cost of reducing CO_2 emissions from power generation.

An equivalent assessment should be undertaken of the leading storage options, using likely transport distances, to arrive at an overall cost of CO_2 abatement for state-of-the-art capture and storage systems.

It is recommended that opportunities be sought to encourage developments that could lead to a reduction in the capital investment required for CO_2 capture. Such opportunities might initially take the form of detailed process designs focussed on taking advantage of opportunities for integration of process activities.

Appendix to the overview: state-of-the-art technology

This appendix contains a brief review of the state-of-the-art for the technologies involved in the leading options assessed in this study. All the component technologies either exist or are believed to be readily adaptable from existing applications, but it is important to note that these technologies have not been integrated into commercial scale power plant in which CO_2 is captured. There is good reason to believe that the CO_2 capture processes can be operated with the performances predicted but this does need to be demonstrated.

NGCC / gas turbines

Natural gas combined cycle plant is established technology that has seen a major decrease in costs over the last 8 to 10 years. Compared to the early 1990s, NGCC plants now sell for approaching half the cost. Currently the major suppliers are producing about 100 units a year, equivalent to an increase in capacity of electricity production of about 30 GW_e/year. World-wide, gas turbine based systems are taking about 30% of the market for power plant which is double the figure of 10 years ago. Demand is projected to increase by 2 to 3%/year.

The specific cost ($/kW) quoted for an NGCC is a 'moving target'. Competition is intense which leads to low initial prices and the impression that manufacturers hope to make much of their profit on spares and future sales. Specific costs as low as 320 $/kWe are quoted in the literature but these are very much 'bare-plant' costs and are unlikely to be representative of the overall cost for an NGCC project (see table 4.2 of the main report).

The gas turbine in the study is based on a GE 9FA giving a combined cycle efficiency of 56%. Within the next 2 to 3 years it is likely that installations based, for example, on the GE 9H, or Siemens work with the V93.3A turbine, will lead to efficiencies of 60% being established state-of-the-art. In the time frame 2010 to 2015 the US DOE's 'Vision 21' programme has targeted developments leading to an NGCC efficiency of over 70%.

Supercritical p/f

Supercritical coal fired power stations have a long history - over 200 supercritical units have been built in the former Soviet Union. In Germany steam temperatures as high as 600°C were in use in the late 1940s and in 1954 Siemens delivered a steam turbine for a supercritical plant working at 300bar and 625°C.[9] In the USA several supercritical plants were built in the 1960s, one of these would probably now be referred to as 'ultra-supercritical' as the conditions were 300bar/650°C/650°C.

There is considerable modern interest in supercritical p/f plant. This is tempered by the fact that the majority of coal-fired power stations are projected to be built in parts of the world where the availability of cheap local coal makes it uneconomic to invest in the exotic materials required for a supercritical plant. Especially as a modern sub-critical unit (180bar/565°C/565°C) can be built with an efficiency in the region of 40%.

In countries where considerable quantities of coal are imported there is an incentive to develop the technology. The Avedøre unit in Denmark is an example of the state-of-the-art, this plant has steam conditions of 300bar/580°C/600°C giving an efficiency of 47% (this is in part attributable to a low cooling water temperature). As another example, Chubu Electric's Kawagoe plant has been in operation since 1989 and runs with steam conditions of 311bar/566C°/566°C/566°C; its efficiency is 45%. Tokyo Electric's Isogo unit scheduled for commissioning in 2001 will have steam conditions of 250bar/600°C/610°C.

[9] 'Critical' conditions in this context refer to the critical pressure. Steam has a critical pressure of about 220bar (and a critical temperature of 374°C).

The key requirement is the development of new materials (e.g. Ni and Cr alloys) that can be economically used. Attempts are being made to develop materials for steam conditions up to 375bar/700°C which will result in efficiencies in the region of 50 to 52%. Such developments are by their nature a sequence of progressive improvements and reaching these conditions is estimated to take up to 20 years.

IGCC / gasification
There is a major debate about the relative merits of electricity production by gasification versus supercritical p/f. It is not the purpose of this study to enter the fray so, for this reason, both types of plant have been used as reference cases. However, it should be pointed out that there are no examples of coal-based IGCC built and operating on a commercial basis to produce electricity; it is therefore stretching the definition of 'state-of-the-art' to use an IGCC reference case in this study.

The study is based on Shell coal gasification technology. Oxygen-blown gasifiers are used because air-blown units are not relevant/suited to CO_2 capture (see report PH2/4).

Gasifiers were first used in Germany immediately prior to World War II and were further developed in South Africa in the early 1980s. In the mid-1980s, the Cool Water project in California, USA successfully demonstrated the use of coal in an IGCC to produce electricity. Since then there have been a number of other demonstration projects notably, Buggenum (Netherlands), Puertolano (Spain), Tampa (USA), and Wabash (USA). The general consensus appears to be that coal-based IGCC has been successfully demonstrated but the capital cost must be reduced to make it competitive in the electricity market. It is often suggested that cleaning the fuel gas before it is burnt, as in IGCC, is a more promising way than cleaning flue gas to achieving 'ultra-clean' power generation using a coal feed – the results of this study emphasise this point, which is particularly relevant if considering removal of CO_2.

Over 300 gasifiers are reported to be in operation but many of these are producers of synthesis gas (CO, H_2, CO_2 mixtures) as an intermediate stage in chemicals production. There is a major interest in the oil industry in the use of gasifiers as a method of treating refinery residues; this can be to produce electricity and/or hydrogen. The well-publicised units in Italy are all designed to process heavy oil residues and generate electricity; the construction of these units has been subsidised by public funding.

Future developments in IGCC technology are largely aimed at reducing the capital cost.

amine-based capture technology
Amine technology has been established for over 60 years in the chemical and oil industries as a means of removing H_2S and CO_2 from gas streams. This experience is largely on natural gas streams and/or in a reducing atmosphere. There are a few facilities in which amines are used in a CO_2 production process to capture it from flue gas streams but they do not produce electricity. The largest operating unit (Trona, Califonia, USA) works at 800 tonnes/day, which is a factor of 10 times smaller than the scale required for the cases in this study.

The accepted wisdom is that MEA is the preferred solvent for CO_2 capture from low-pressure flue gases. There are, however, major questions about its rate of degradation in the oxidising environment of a flue gas. Rooney et.al.[10] report that, of the many amine-based solvents they assessed, MEA is the most vulnerable to oxidation. Also, highly reactive solvents like MEA require considerable energy for regeneration. Trials with two proprietary MEA solvents on the flue gas of a coal-fired boiler, led Wilson et.al.[11] to report that: "Both solvents recorded good CO_2 absorption capacity, with recovery rates consistently in the 98% range. Product purity was also good, with values in excess of 99%. The inhibitors and stabilizers provided by the solvent suppliers worked effectively to reduce corrosion and improve the amine tolerance to high oxygen levels…". MEA solvent is therefore considered the present 'state-of-the-

[10] Rooney P C, DuPart M S, Bacon T R, 'Oxygen's role in alkanolamine degradation', Hydrocarbon Processing, July, 1998.
[11] Wilson M A, Wrubleski R M, Yarborough L, 'Recovery of CO_2 from power plant flue gases using amines', *Energy Convers. Mgmt* Vol. 33, No. 5-8, pp. 325-331, 1992

art' even though its use has not been demonstrated in the power generation applications assessed in this report.

The development of improved solvents is seen by many as being both feasible and the key to reducing the penalties for CO_2 abatement in power generation. (Chakma[12]) concludes that "Properly formulated solvents can reduce energy requirements by as much as 40% compared to conventional MEA solvents'.

There is considerable interest in the use of sterically-hindered amine solvents[13] because they are claimed to have good absorption and desorption characteristics. Exxon[14] claim 19 plants use their 'Flexsorb SE' hindered amine solvent - we do not know if any of these gas streams present an oxidising environment for the solvent. The new solvents developed by Mitsubishi are believed to be hindered amines.[15]

A key requirement is to limit losses of solvent both as 'carry-over' in the flue gas and as heat-stable salts. The quantities involved are speculative but it has been suggested that the losses from use for CO_2 capture at a 500MW gas-fired power station could be about 2 000 tonnes/year of sludge formed by decomposed amines, and about 10 tonnes/year of carry-over in the flue gas. The environmental implications are not well documented.

(The physical solvents used on feeds from a shift conversion to capture CO_2 are not discussed here as they are well established in this role e.g. in ammonia production.)

POCC / partial oxidation

Partial oxidation of natural gas is widely used in the chemical industry to produce synthesis gas as an intermediate in the production of hydrogen, methanol, ammonia, etc. Various combinations of partial oxidation and steam reforming are used depending on the desired product. This processing route is not used for power generation as natural gas can be used directly.

Previous work by IEA GHG in this area (see report PH2/19) has focussed on the use of air-blown partial oxidation units to avoid the costs associated with air separation. The relative merits of air-blown and oxygen-blown partial oxidation depend on the amount of energy carried out of the reactor as sensible heat. In the case of coal gasification the temperatures are usually high (1600°C before quench in the reference case for this study) and oxygen is preferred. Natural gas partial oxidation takes place at lower temperatures (about 900°C) and IEA GHG studies have shown that in this case air-blown units could be preferred (see forthcoming study PH3/21). The presence of nitrogen need not be a barrier to use for CO_2 emission abatement (seePH2/19) but is generally to be avoided in synthesis gas production (all known partial oxidation units work on oxygen or at least enriched air). In order to base this study on state-of-the-art technology and provide calibration of the partial oxidation options, an oxygen-blown partial oxidation reactor (operating at 1050°C) is considered here.

combustion of hydrogen-rich gases in a gas turbine

In the IGCC and POCC cases where CO_2 is captured, it is assumed that the decarbonised synthesis gas (the combustible content of which is essentially hydrogen) can be burnt in an existing gas turbine with little modification. This is not demonstrated technology; normally synthesis gas has an appreciable CO

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[12] Chakma A, Tontiwachwuthikul P, 'Designer solvents for energy efficient CO_2 gas separation from flue gas streams', Proceedings of GHGT-4, Aug/Sept 1998, Interlaken, Switzerland, pages 35 – 42.

[13] A sterically hindered amine is a branched-chain aliphatic compound as opposed to the straight-chain aliphatic compounds of conventional amine solvents. The branched-chain destabilises carbamates encouraging them to dissolve in water. 2-amino-2-methyl-1-propanol [$HO\text{-}CH_2\text{-}C(CH_3)_2\text{-}NH_2$], known as AMP, is representative of sterically-hindered amines c.f. MEA [$HO\text{-}CH_2\text{-}CH_2\text{-}NH_2$].

[14] Exxon, "Flexsorb solvents - Gas Processes '98", Hydrocarbon Processing April 1998, page 102.
Kohl & Riesenfeld ' Gas Purification' published by McGraw-Hill.

[15] Mimura T, Satsumi S, Iijima M, Mitsuoka S, 'Development of energy saving technology for flue gas CO_2 recovery by the chemical absorption method and steam system in power stations', Proceedings of GHGT-4, Aug/Sept 1998, Interlaken, Switzerland, pages 71 – 76.

content, which is not present in the cases considered here.[16] Use of gas turbines in this application is not seen to be an insurmountable obstacle, as problems with NO_x or power augmentation can be dealt with by adding nitrogen and/or steam. Both ABB and GE are known to have undertaken tests with the objective of establishing criteria for the combustion of hydrogen-rich fuels. This topic is dealt with in some depth in a forthcoming report (PH3/12). For the purposes of this study it is assumed that an existing GE frame 9F turbine can be suitably modified.

partial recycle of flue gas

We know of no practical application where a gas turbine is fired with a mixture of recycled flue gas and combustion air. Recycle of flue gas in this processing scheme reduces the oxygen level in the feed to the turbine from 21vol% to 13vol%. The amount of recycle is set by the minimum O_2 level at which it is believed the gas turbine could be made to operate with only minor modifications. Although similar schemes have been suggested by several researchers, it is not known if anybody is actively progressing this idea.

[16] GE report on their synthesis gas experience in: Todd D M, 'IGCC experience and technology improvements spreading to other process/power plants', PowerGen '99, Frankfurt, June 1999. The maximum hydrogen concentration reported as burnt in an advanced frame F machine is 37.2%mole. Higher concentrations of hydrogen have been successfully burnt, but in less advanced machines.

FINAL REPORT

FOR

ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

IEA GREENHOUSE GAS R&D PROGRAMME UNITED KINGDOM

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1. SUMMARY AND CONCLUSIONS

This report presents the results of the study "The assessment of leading technology options for abatement of CO_2 emissions", carried out by Stork Engineering Consultancy for The International Energy Agency, within the Greenhouse Gas R&D Programme.

In total eight electricity production processes have been evaluated. Of these eight, three cases have been defined as reference cases. These three cases are state of the art electricity production processes:

(i) natural gas fired combined cycle ($G1_{wo}$)
(ii) pulverised coal fired power plant ($C1_{wo}$)
(iii) integrated gasification combined cycle ($C2_{wo}$)

Based on these three reference cases five options have been evaluated with Carbon dioxide capture and storage:

(i) natural gas fired combined cycle with CO_2 capture using an amine-based solvent ($G1_w$).
(ii) reforming of natural gas followed by CO shift and CO_2 capture. The hydrogen rich product is used as fuel in the combined cycle ($G2_w$).
(iii) natural gas fired combined cycle with re-circulation of the flue gases and CO_2 capture using an amine-based solvent ($G3_w$).
(iv) pulverised coal fired power plant with CO_2 capture using an amine ($C1_w$).
(v) integrated gasification combined cycle with CO shift and CO_2 capture. The hydrogen rich product is used as fuel in the combined cycle ($C2_w$).

1.1 CONCLUSIONS THERMODYNAMIC EVALUATION

The state of the art power production processes have been evaluated based on a consistent set of starting points and assumptions. The following table presents the results of the three reference cases:

Case	*G1wo*	*C1wo*	*C2wo*
Net efficiency (%, LHV)	56.2%	45.6%	46.3%
Net power (MWe)	790	501	408

Table 1.1: Results thermodynamic evaluation reference cases

Based on the three reference processes, the five CO_2 capture processes have been evaluated. The main results are presented in the following table:

Case	*G1w*	*G2w*	*G3w*	*C1w*	*C2w*
Net efficiency (%, LHV)	47.2%	48.3%	47.8%	33.0%	38.2%
Net power (MWe)	663	820	666	362	382
Efficiency reduction (%) (compared to reference)	16%	14%	15%	28%	17%

Table 1.2: Results thermodynamic evaluation CO_2 capture cases

As the results show, the efficiency drops significantly if carbon dioxide is captured. The efficiency of the post-combustion decarbonisation processes as G1w and C1w show a relatively large reduction in efficiency, respectively 16% and 28%.
The efficiency drop of the pre-combustion decarbonisation processes, G2w and C2w is considerably lower, respectively 14% and 17%.
The impact of carbon dioxide capture on overall efficiency can be explained by different influences. An important aspect with CO_2 capture based on amine solvents is its energy consumption for regeneration of the solvent. In principle this energy consumption is based on the absolute quantity of carbon dioxide. Thus, the captured CO_2 in the solvent defines the required amount of energy for regeneration. As coal produces considerably more CO_2, the required heat is proportionally high. This holds mainly for the atmospheric capture of CO_2 as in case G1w, G3w and C1w, the post combustion decarbonisation processes.
With regard to the pre-combustion decarbonisation processes in which the fuel is converted to synthesis gas which has the advantage that carbon dioxide becomes available at high pressure and high concentrations, other solvents can be used, making use of the available pressure for regeneration. This possibility has a great affect on the energy consumption for regeneration and thus the overall efficiency as can be seen if one compares G1w with G2w or comparing C1w with C2w.

1.2 CONCLUSIONS ECONOMIC EVALUATION

The reduction in efficiency as well as the increase in investment and cost for operation and maintenance lead to an increase of the production cost for electricity. For each power generation process, an investment estimate has been made together with an estimate of the cost for operation and maintenance. The following table shows the total plant investment for the three reference cases:

Case	*G1wo*	*C1wo*	*C2wo*
Total plant investment (mln US$)	327	512	600
Specific plant investment (mln US$/kWe)	414	1022	1471

Table 1.3: Plant investment for reference cases absolute and specific

Based on these reference processes, the investment for the five CO_2 capture processes has been estimated. The main results are presented in the following table:

Case	*G1w*	*G2w*	*G3w*	*C1w*	*C2w*
Total plant investment (mln US$)	521	743	477	672	842
Specific plant investment (mln US$/kWe)	787	906	716	1856	2201
Investment increase (%) Compared to reference	59%	127%	46%	31%	40%

Table 1.4: Plant investment for CO_2 capture cases, absolute and specific

The investment, necessary to remove a considerable part of the produced carbon dioxide, has been estimated. The results show that the differences in investment are enormous. For natural gas fired power plants, investment increases of 45 to 130% are estimated. The post-carbonisation process is characterised by large sized equipment. This equipment can be designed smaller if flue gases are recirculated to the gas turbine. In this way a higher concentration of CO_2 in the flue gas will be established resulting in smaller equipment and thus lower investment.

The process of pre-combustion decarbonisation results in an increase of the investment of more than 100%. This is due to the large amount of additional equipment necessary to convert the natural gas into synthesis gas followed by conversion to CO_2 and removal of CO_2.

Based on a cash flow projection an evaluation has been made of the production cost of electricity. The assumptions necessary to make the cash flow projection have been described into detail in the report. The results are presented in the following table:

Case	*G1wo*	*C1wo*	*C2wo*
kWh production cost (US$/kWh)	0.0216	0.0374	0.0478
CO_2 emitted (kg/sec)	81.2	100.5	80.5
CO_2 emitted (kg/MWh)	370	722	710

Table 1.5: kWh production cost and CO_2 emission figures for reference cases
(Discount rate: 10%)

The same calculation has been performed for the five CO_2 capture processes. The kWh price is presented in the following table. The table includes the resulting cost for the CO_2 capture presented in US$ per captured ton of CO_2.

Case	*G1w*	*G2w*	*G3w*	*C1w*	*C2w*
kWh production cost (US$/kWh)	0.0323	0.0344	0.0307	0.0635	0.0691
CO_2 emitted (kg/sec)	11.2	14.9	11.7	14.9	14.2
CO_2 emitted (kg/MWh)	61	65	63	148	134
Compared to reference case:	***G1wo***	***G1wo***	***G1wo***	***C1wo***	***C2wo***
Production cost increase (US$/kWh)	0.0107	0.0128	0.0091	0.0261	0.0213
CO_2 reduction (kg/MWh)	309	305	307	574	576
Cost CO_2 capture (US$/ton CO_2)	**35**	**42**	**30**	**45**	**37**

Table 1.6: kWh production cost and CO_2 emission figures for CO_2 capture cases and cost CO_2 capture
(Discount rate: 10%)

The table presented above summarises the results of this project. The cost of the captured CO_2 includes all influences on the electricity production. Not only the additional investment but also the loss in efficiency and the increase in cost for operation and maintenance are included.

1.3 CONCLUSIONS

It is obvious that power production based on natural gas has the highest achievable efficiency. Efficiencies in the range of 55% to 57% are possible and further increase of efficiency appears to be possible with new developments in gas turbine design. With regard to Carbon dioxide emission, natural gas is also preferred above coal. Not only because of the higher efficiency but also because of the carbon content of the fuel. The carbon content of coal is approximately 60% higher than for natural gas (related to the lower heating value, in this case Norwegian gas, Australian coal).

If a considerable decrease in carbon dioxide emission is necessary, improvements in efficiency will contribute partly. However, improvements in the range of 80 to 90% carbon dioxide reduction can not be achieved with efficiency improvement. Other techniques need to be applied. Examples have been investigated in this project.

Based on the capture cost of CO_2, which includes all relevant parameters the following conclusions have been made, firstly divided into natural gas and coal based power production.

1.3.1 Natural gas based power production

An obvious possibility to significantly reduce carbon dioxide emission is to capture the CO_2 from the exhaust gases by means of an amine solvent. The technology is widely used for other purposes and several amine solvents have the characteristics to capture CO_2. As can be seen from the results, CO_2 capture by means of amine scrubbing is an expensive method. This can be explained by the large volume flows of flue gas which have to be treated and the low concentration of the CO_2. This led to the description of other processes which either reduce the volume flow by means of re-circulation of the flue gas or by means of pre-combustion decarbonisation. Especially the first process appears to decrease the CO_2 capture cost. Re-circulation increases the CO_2 concentration and decreases the volume flow. This results in considerably smaller equipment for the treating section and thus reduction in investment. The pre-combustion decarbonisation process in which natural gas is converted to synthesis gas is preferable with regard to efficiency. However, as additional expensive equipment is necessary, this option is still less competitive.

The combination of low investment and low decrease in efficiency results in the lowest CO_2 capture cost, as is the case with the recirculation of flue gases.

1.3.2 Coal based power production

Power production based on coal as a fuel is a large contributor to carbon dioxide emission. As stated above the carbon content of coal is approximately 60% higher than of natural gas. Moreover, the efficiency of coal based power production is considerably lower. A means of increasing the efficiency is to use the gasification technology which opens the possibility of using the lower heating value of the coal on a higher temperature (in the gas turbine) which is exergetically preferable. As this technology is commercial available at this moment the Integrated Gasification Combined Cycle (IGCC) technology has been evaluated as well.

Carbon dioxide capture from coal based power production has been investigated and analysed. CO_2 capture at conventional power production based on steam cycle technology is possible with amine based solvents. The flue gases can be treated with these solvents to capture part of the carbon dioxide. Compression and storage in the subsoil of the captured CO_2 reduces the emission considerably. However, again the large volume flows and the low concentration of CO_2 causes the investment to be extremely high. Also the large demand for heat to regenerate the solvent has a high impact on the efficiency. Therefore the CO_2 capture cost are as high as 45 US$/ton CO_2 captured.

Pre-combustion decarbonisation technology can decrease this cost. IGCC offers this possibility as coal is converted to synthesis gas. The synthesis gas can be treated by means of shifting the carbon monoxide to carbon dioxide. In this way the carbon dioxide is available in a concentrated flow on high pressure. The advantages are small volumes, high concentrations which affect the dimensions of the CO_2 capture processes. Also the high pressure make it possible to use physical solvents which need less heat for regeneration. As the results show, a decrease in CO_2 capture cost from 45 to 37 US$ per ton CO_2 captured is possible. It is very important to realise that the CO_2 capture cases have been compared to their reference case. Thus CO_2 capture applied after a conventional coal plant is compared to a conventional coal plant and CO_2 capture applied after an IGCC has been compared to an IGCC. If the cost of CO_2 capture at the IGCC power plant is compared to a conventional coal fired plant, the CO_2 capture cost increase to 55 US$ per ton CO_2 captured. This means that one can conclude that IGCC technology is not preferable above conventional coal fired technology with regard to carbon dioxide removal. This is mainly due to the relatively high production cost of electricity in the reference IGCC. It is important to realise that this conclusion is based on all assumptions mentioned.

1.3.3 Natural gas versus coal fired power plants

The cost per ton of CO_2 removed from natural gas fired power plants is lower than the cost from coal fired power plants. The most important reason for this is the low carbon content of natural gas and thus the lower carbon dioxide emission per kWh produced.
An important conclusion is, if CO_2 removal becomes an important factor to realise in the design of power plants, that the designs will be different. Especially the pre-combustion decarbonisation technologies prove to be able to remove CO_2 at a lower cost that the post combustion decarbonisation technologies. Also possibilities as the recirculation of flue gas in case of natural gas fired combined cycles provide a means to increase the efficiency.
If the use of coal as a fuel in power generation will increase, gasification will provide the technology to increase the efficiency and the possibility to remove CO_2 at a relatively low cost. However, based on the assumptions used, the production cost of electricity using the IGCC technology is still higher than if conventional technologies are used.

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2. INTRODUCTION

This report presents the results of the project "*Assessment of leading technology options for abatement of CO_2 emissions*". This study has been carried out for The International Energy Agency, Greenhouse Gas R&D Programme, to determine the cost of carbon dioxide reduction processes at power generation plants.

2.1 GENERAL

The power generation industry consumes high amounts of fossil fuel and consequently contributes significantly to the emission of greenhouse gases. Therefore, reducing these emissions is very effectively in terms of reducing the global emission of greenhouse gases.

However, carbon dioxide emission reduction is a relatively new field, which until recently has not had much attention from the power generating industry. Conventionally, the only way to reduce carbon dioxide emissions is by increasing the efficiency. If deep reductions in carbon dioxide were required in power generation, processes to capture and store carbon dioxide are inevitable.

The state of the art power generating processes are natural gas and coal fired power plants. Carbon dioxide can be captured from the flue gases (end of pipe solution or post-combustion decarbonisation) or by converting the fossil fuel to an intermediate fuel which makes capture of the carbon dioxide more effective (pre-combustion decarbonisation).

IEA has defined the study "*The assessment of leading technology options for abatement of CO_2 emissions*" as part of their IEA Greenhouse Gas R&D Programme (IEA-GHG). The purpose of this study is to assess the technical and economic characteristics of four power generating processes, with and without carbon dioxide capture, in detail. This means amongst others quantifying the emission data, the efficiencies and the economical characteristics of the selected options. These cases are based on our in-house data information on actual data of power plants.

The information generated in this study will be used by IEA as references against which other mitigation options are calibrated.

2.2 PROJECT APPROACH

In the Invitation to Tender from IEA-GHG (reference IEA/CON/98/40, dated August 3rd, 1998), four capture and storage processes together with their equivalent non-capture base-cases are defined by IEA-GHG to be assessed in this study. The following power generation processes have been evaluated:

Natural gas based power generation

$G1_{w/o}$: Power generation in a combined cycle

$G1_w$: Power generation in a combined cycle with carbon dioxide removal from the flue gases using an amine-based solvent

$G2_w$: Conversion of natural gas to a synthesis gas followed by CO shift and CO_2 removal. The hydrogen-rich product can be used in a combined cycle to produce electricity.

$G3_w$: An additional process option which has been evaluated is the capture and storage of CO_2 from natural gas fired combined cycles using partial flue gas re-circulation. By re-circulating part of the flue gases to the gas turbine compressor, the CO_2 concentration will increase which facilitates the CO_2 removal, especially in terms of energy consumption.

Coal based power generation

$C1_{w/o}$: Power generation in a supercritical steam cycle

$C1_w$: Power generation in a supercritical steam cycle combined with carbon dioxide removal from the flue gases using an amine-based solvent

$C2_{w/o}$: Power generation in an integrated coal gasification combined cycle

$C2_w$: Power generation in an integrated coal gasification combined cycle followed by CO shift and CO_2 capture. The hydrogen-rich product can be used in a combined cycle to produce electricity.

Three of the power generation processes ($G1_{w/o}$, $C1_{w/o}$ and $C2_{w/o}$) are the state of the art processes without CO_2 capture and storage, presented in the case as $_{w/o}$ and five processes ($G1_w$, $G2_w$, $G3_w$, $C1_w$ and $C2_w$) are with CO_2 capture and storage, presented in the case as $_w$. Process $G2_w$ has no base-case version other than the reference case $G1_{wo}$.

Of the processes in which CO_2 is captured and stored, three processes are post-combustion decarbonisation processes ($G1_w$, $G3_w$ and $C1_w$) and two processes are pre-combustion decarbonisation processes ($G2_w$ and $C2_w$).

In all cases the processes to be assessed will be state-of-the-art for construction starting in the year 2000. This is important for the selection of for instance the gas turbine and the steam cycle properties (temperature and pressure).

For each case the following steps have been performed:

- Introduction and description of the process;
- Thermodynamic calculation of the process;
- Determination of specific energy consumption figures for the main process units and conversion processes;
- Economic evaluation of the process.

Based on the above mentioned results for each of the five processing schemes with CO_2 capture and storage, the cost and efficiency penalties for adoption of capture and storage of CO_2 have been determined as well as the reduction in emissions achieved. The cost of avoiding CO_2 emissions (US$/ton CO_2) has been calculated.

A sensitivity analysis has been performed in which the influence on the cost of electricity of the following parameters will be assessed for all processes:

- Discount cash flow rate of 5% (base case is 10%);
- Cost of fossil fuel (range);
- Pressure of the CO_2 exported (60, 80 and 110 bar).

3. MASS & ENERGY BALANCES

3.1 INTRODUCTION

The full mass & energy balances of all power generating cases are presented in the appendixes to this report. This section gives a brief description of the cases and a summary of the results.

The power generating cases can be subdivided by type of fuel and by type of CO_2 removal. The type of fuel is either natural gas or pulverised coal. The type of CO_2 removal is either pre combustion, post combustion or no CO_2 removal at all. The following table illustrates this:

	no CO_2 removal	*pre-combustion CO_2 removal*	*post combustion CO_2 removal*
natural gas	G1wo	G2w	G1w / G3w
coal	C1wo / C2wo	C2w	C1w

Table 3.1: Classification of the power generating cases

The following power generating case will be evaluated, the full mass and energy balance can be found in the specified appendix:

Appendix	*Case*	*Description*
1	G1wo	Combined Cycle without CO_2 capture
2	G1w	Combined Cycle with CO_2 capture
3	G2w	Combined Cycle with integrated reformer and CO_2 capture
4	G3w	Combined Cycle with recirculation of the flue gasses and CO_2 capture
5	C1wo	Pulverised Coal power plant without CO_2 capture
6	C1w	Pulverised Coal power plant with CO_2 capture
7	C2wo	IGCC without CO_2 capture
8	C2w	IGCC with CO_2 capture

Table 3.2: Power generating cases

The mass and energy balances of the power generating processes, have been calculated with Gate Cycle. The Gate Cycle program allows for very accurate calculations of the

performance of the processes/plants concerned. It is therefore possible to incorporate all losses which may be applicable in a model. For study purposes, however, it is normal practice to ignore minor losses as they do not affect the overall result of the study.
For this study simulation models have been developed with state of the art performance/efficiency characteristics which are applicable for these type of plants (degradation/fouling characteristics have not been included).

3.2 DESCRIPTION OF THE CASES

3.2.1 Natural Gas Based Power Generation

G1wo

Power generation in a combined cycle. Two General Electric Frame 9FA heavy duty gas turbines generates electricity and hot exhaust gas. A Heat Recovery Steam Generator, HRSG, produces steam at three pressure levels for the steam turbine. The steam turbine generates electricity. This case has no means of CO_2 recovery.

G1w

Power generation in a combined cycle with CO_2 removal from the flue gases. The method of power generation is the same as in case G1wo. Flue gas exiting the HRSG passes through an absorber / stripper combination where 85% of the CO_2 is removed using a MEA solution. The MEA solution chemically binds the CO_2, heat duty is necessary to release the CO_2 from the solution. The washed flue gas leaves the absorber column into the atmosphere. The CO_2 leaves the stripper and is compressed to injection pressure and cooled down.

G2w

Conversion of natural gas to a synthesis gas in an autothermal reformer. A double shift reactor converts the CO rich syngas to a mixture of H_2 and CO_2. The CO_2 is then removed from the syngas by a Selexol solution in an absorber. A high partial pressure of CO_2 in the syngas allows the usage of a physical bounding based solution such as Selexol. The washed syngas is then used as a fuel gas for a combined cycle. The design of the combined cycle is in accordance with case G1wo. The gas turbine compressor supplies air to the air separation unit, which generates oxygen necessary for the autothermal reformer.

G3w

Partial flue gas recycling in natural gas fired combined cycles. By re-circulating part of the flue gasses to the gas turbine compressor, the CO_2 concentration will increase which facilitates the CO_2 removal, especially in terms of energy consumption. The design of the combined cycle and the MEA based absorber stripper combination is in accordance with case G1w.

3.2.2 Coal Based Power Generation

C1wo

Coal fired power generation with a super-critical steam cycle. Coal is burnt in a pulverised fuel power plant with a Benson tower type boiler. The plant operates with a super critical steam cycle with conditions of 310 bar and 593 °C. The plant is equipped with a flue gas desulphurisation unit. NO_x emissions are minimised through low NO_x burners and Selective Catalytic Reduction in the flue gas. CO_2 is vented into the atmosphere as a constituent of the flue gas.

C1w

Coal fired power generation with a super critical steam cycle with CO_2 capture from the flue gas. This design is in accordance with case C1wo, with the addition of an absorber / stripper combination where 85% of the CO_2 is removed from the flue gas using a MEA solution. The MEA solution chemically binds the CO_2, heat duty is necessary to release the CO_2 from the solution. The washed flue gas leaves the absorber column into the atmosphere. The CO_2 leaves the stripper and is compressed to injection pressure and cooled down.

C2wo

Power generation in an Integrated coal Gasification Combined Cycle, IGCC. Coal is gasified using the Shell technology. The syngas produced is cooled down and cleaned using a cold gas treatment. The cleaned syngas is then combusted in a modified General Electric frame 9 FA type gas turbine. The exhaust gasses of the Gas Turbine pass through a double pressure Heat Recovery Steam Generator. A Steam turbine generates power. The IGCC has full steam integration, Steam is produced in the gasifier water walls and in the gas cooling section. The gas turbine compressor provides air for the Air Separation Unit.

C2w

Power generation in an integrated coal gasification combined cycle followed by CO shift and CO_2 capture. The design of the power plant is in accordance with the IGCC from case C2wo. After the syngas has been cleaned and cooled down the syngas enters a double shift reactor where the CO is converted to CO_2 and H_2. A Selexol based absorber then physically separates the CO_2 from the syngas flow, the washed syngas is then combusted in a gas turbine combined with a double pressure HRSG.

3.3 RESULTS

The final results of the mass & energy balance are presented as absolute figures and specific figures in the following tables:

Case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
Fuel Input (MWth LHV)	1406	1406	1696	1394	1098	1098	880	1002
Gas Turbine power (MWe)	509	509	574	491	-	-	251	283
Steam turbine power (MWe)	294	205	361	225	534	441	192	184
Balance of Plant (MWe)	-13	-9	-20	-11	-33	-31	-15	-16
Air separation unit (MWe)	-	-	-63	-	-	-	-20	-38
CO_2 recovery (MWe)	-	-14	-5	-12	-	-13	-	-5
CO_2 compressor (MWe)	-	-28	-27	-28	-	-34	-	-25
Total Net power (MWe)	790	663	820	666	501	362	408	382
Net efficiency	56.2 %	47.2 %	48.3 %	47.8 %	45.6 %	33.0 %	46.3 %	38.2 %
Total CO_2 produced (kg/s)	81.2	81.2	98.0	80.6	100.5	100.5	80.5	91.7
CO_2 to injection (kg/s)	-	70.0	83.1	68.9	-	85.6	-	77.5
CO_2 capture level	-	86.2 %	84.8 %	85.5 %	-	85.2 %	-	84.5 %

Table 3.3: Energetic results in absolute figures with CO_2 recovery data.

Case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
Gas Turbine power	6268	6268	5857	6092	-	-	3118	3086
Steam turbine power	3621	2525	3684	2792	5313	4388	2385	2007
Balance of plant	-160	-111	-204	-136	-328	-308	-186	-174
Air separation unit	-	-	-643	-	-	-	-248	-414
CO2 recovery	-	-172	-51	-149	-	-129	-	-55
CO2 compressor	-	-345	-276	-347	-	-338	-	-273

Table 3.4: Energetic results in specific figures (MWe per ton CO_2/s).

The specific results show clearly the differences in energetic merits between the cases. The following major effects can be noted:

Gas turbine power:

- In absolute figures the gas turbine produces more power when combusting a hydrogen rich fuel as can be seen from cases G2w and C2w. This is due to the high expansion enthalpy of H_2O, the combustion product of hydrogen.
- Case G2w shows a decrease in power / ton CO_2. This is due to the cold gas efficiency of the autothermal reformer and double shift reactor. More fuel is used to produce a certain fuel input for the Gas Turbine, and therefore more CO_2 is produced.
- Case C2w experiences the same effect. The double shift reactor has a cold gas efficiency and therefore more fuel is consumed than is inserted the gas turbine. The heat produced by the double shift reactor is off course used in the steam system.
- The power output of the gas turbine in the recycle case G3w is lower than G1wo due to the high inlet temperature of the recycled exhaust gas.

Steam turbine

- The steam turbine production in case C2wo and C2w is low due to amongst others to the smaller size of the plant.
- The steam turbine produces significantly less electric power in the cases with chemically based solvent for CO_2 removal (G1w, G3w, C1w). This is mainly due to the fact that the reboiler of the MEA absorber stripper combination consumes quite some energy.
- The cases with a physically based solvent perform a lot better. This is due to the fact that no steam is necessary for regenerating the solvent. In addition the double shift reactor produces steam which can be used for the steam turbine.

Balance of Plant

- The usage of a chemically based solvent in cases G1w, G3w and C1w which has to be regenerated by condensing steam in a reboiler reduces the load on the main condenser. This reduces the power necessary for cooling water pumps and therefore the energy required for Balance of Plant.
- Cases G2w and C2w using a physically based solvent to remove CO_2 have a higher penalty for the Balance of Plant losses. This is due to the fact that the double shift reactor generates some steam, and therefore more pump capacity has to be installed.

Air Separation Unit

- The Air Separation Unit performs quite differently for the different cases (G2w, C2wo, C2w). This mainly due to the integration with the gas turbine compressors. The integration is such that as much air is extracted from the gas turbine compressor until the total flow of fuel and air through the gas turbine expander becomes equivalent to a gas turbine fired by natural gas. This method of modelling gives for each type of fuel a different amount of air that can be extracted. This amount of air determines how much extra air has to be compressed to supply the Air Separation Unit with enough air for the oxygen requirements of the autothermal reformer and gasifier. Thus the amount of energy necessary for ASU varies significantly per case.

CO_2 recovery

- Again the cases with chemically based CO_2 removal (G1w, G3w, C1w) perform worse than the physically based solvents. The high flows of solvent in these cases and the high demand for cooling water pumps, increases the power demand by the CO_2 recovery unit. Especially the figures in table 2.2, where the energy losses are related to the CO_2 produced clearly shows these differences. The cases which use the chemical solvents (G1w, G3w and C1w) consume 130 to 170 MWe per produced ton/sec CO_2, whereas the cases with physical solvent (G2w, C2w) consume only 50 to 55 MWe per produced ton/sec CO_2.

CO_2 compression

- The physically based CO_2 recovery unit releases half the CO_2 at 6.3 bars. The other half is released at 1.5 bar, just as the complete amount of CO_2 in chemically based solvents is released. This means that the CO_2 from cases G2w and C2w can be compressed with a lower energy use than the other CO_2. Again in table 2.2 this difference is clearly presented. The cases which use the chemical solvents (G1w, G3w and C1w) consume 335 to 350 MWe per produced ton/sec CO_2, whereas the cases with physical solvent (G2w, C2w) consume only 275 MWe per produced ton/sec CO_2.

4. ECONOMIC ANALYSIS

4.1 CAPITAL COST FIGURES

4.1.1 Introduction

The capital cost figures of the various configurations considered have been based on the following:

- For the power generating and gasification systems actual cost figures from plants recently taken into operation and/or under construction have been used.
- For the reforming and CO2 capture and storage processes the cost figures have been based on estimates which have been related to the cost figures for similar systems.
- In all cases the processes to be assessed are state-of-the-art for construction in the year 2000. Up-to-date developments both in power generation and CO2 capture technology have been included in the process definition.
- The plants will be assumed to be on the NE coast of the Netherlands, within 1 km of the sea.
- A green field site with no special civil work implications will be assumed.
- The plant will be built on a turnkey basis and shall be provided with all required (auxiliary) systems. The closed cooling water system in the plant will be cooled with sea water (i.e. indirect cooling with sea water). Facilities and infrastructure required outside the plant limit, e.g. HV connection, fuel supply, etc., are not included in the cost estimate

The overall accuracy of the cost estimates is in the range of ± 25 %

All cost with respect to the power generating system are presented as one total cost figure. The individual cost for all individual systems/activities such as individual equipment, auxiliary systems, civil, electrical, instrumentation, etc. are not presented.
To present an accurate cost overview for all individual systems/activities a great effort is required as this is only possible with a detailed definition per system/activity. As a (detailed) cost break down will not contribute to the aim of this study, which is the overall comparison of the processes concerned with and without CO2 capture, only the total cost per main item/process is presented.
Therefore the cost estimate is split up in the following items:

- power generating system

- CO2 capture system
- CO2 compression system

In accordance with the starting points of this study the power generating systems with and without the capture and storage of liquefied CO2 are identical except for the processes/equipment required to capture and compress most of the produced CO2. Therefore all cost required for capturing and compressing the CO2 has been accounted to the CO2 capture and or compression system even if this would require e.g. a modification of the power generating system. The cost for transport and storage of the CO2 outside the plant limit are not included in the cost estimate.

For determining the overall project cost the following additional charges are applicable:

- a cost of 5 % of the installed plant cost (overnight construction) will be assumed to cover land purchase, surveys, general site preparation, etc..
- a cost of 1 % of the installed plant cost (overnight construction) will be assumed to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments.
- a cost of 2 % of the installed plant cost (overnight construction) will be assumed to cover fees in addition to the contractor’s fees for designing and building the plant.
- a factor of 10 % of the installed plant cost (overnight construction) will be assumed to cover project contingency.

4.1.2 Investment cost

A summary of the investment cost (excluding interest during construction) for the configurations considered in this study is presented in table 1.1. The specific costs in US$ per kWe of installed capacity are presented in table 1.2

case		*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
Net power Output in MWe		789.9	662.7	819.8	665.8	500.7	362.2	407.8	382.4
Power Generating System		277.3	277.3	277.3	277.3	433.6	433.6	504.1	549.9
CO2 capture system		n.a.	127.8	296.9	90.9	n.a.	92.3	n.a.	106.5
CO2 compression system		n.a.	29.4	29.5	29.0	n.a.	34.4	n.a.	27.9
Total Installed Plant cost		277.3	434.5	603.7	397.2	433.6	560.2	504.1	684.2
land purchase, surveys,...	5%	13.9	21.7	30.2	19.9	21.7	28.0	25.2	34.2
specific services	1%	2.8	4.3	6.0	4.0	4.3	5.6	5.0	6.8
fees	2%	5.5	8.7	12.1	7.9	8.7	11.2	10.1	13.7
contingencies	10%	27.7	43.4	60.4	39.7	43.4	56.0	50.4	68.4
confidence limits	var.	0.0	8.7	30.2	7.9	0.0	11.2	5.0	34.2
Overall plant cost		327.2	521.4	742.5	476.7	511.6	672.2	599.9	841.6

Table 4.1: Total plant Cost in MLN US$.

case		*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
Power Generating System		351.1	418.5	338.2	416.5	866.0	1196.9	1236.4	1437.9
CO2 capture system		n.a.	192.8	362.1	136.6	n.a.	254.7	n.a.	278.4
CO2 compression system		n.a.	44.3	35.9	43.6	n.a.	94.9	n.a.	72.9
Total Installed Plant cost		351.1	655.6	736.3	596.6	866.0	1546.5	1236.4	1789.2
land purchase, surveys,...	5%	17.6	32.8	36.8	29.8	43.3	77.3	61.8	89.5
specific services	1%	3.5	6.6	7.4	6.0	8.7	15.5	12.4	17.9
fees	2%	7.0	13.1	14.7	11.9	17.3	30.9	24.7	35.8
contingencies	10%	35.1	65.6	73.6	59.7	86.6	154.6	123.6	178.9
confidence limits	var.	0.0	13.1	36.8	11.9	0.0	30.9	12.4	89.5
Overall plant cost		414.3	786.8	905.7	715.9	1021.9	1855.8	1471.3	2200.8

Table 4.2: Specific plant Cost in US$ / kWe

Case description:

G1w/oCombined Cycle without CO2 capture

G1w Combined Cycle with CO2 capture

G2w Combined Cycle with integrated reformer and CO2 capture

G3w Combined Cycle with recirculation of the flue gasses and CO2 capture

C1wo Pulverised Coal power plant without CO2 capture

C1w Pulverised Coal power plant with CO2 capture

C2wo IGCC without CO2 capture

- Specific investment used for Air Separation Unit in case C2WO: 77 US$/kWth (on fuel input) on 166 US$/kWe (on electricity output).
- Specific investment used for SCR unit in case C1WO: 10.6 US$/kWth or 23 US$/kWe (on electricity output).

4.2 CASH FLOW PROJECTION

4.2.1 Background

Using the cash flow projection one can determine the real cost of electricity production. This paragraph shows the calculation method and the criteria used. As a result the cost of electricity production are summarised.

The cash flow projection shows the cash flows of a power plant throughout its lifetime and calculates the net present value of these cash flows. The net present value (NPV) is the value of a project today if all future cash flows (including investments) are discounted to today's value using a discount ratio.

The cash flows include the following items:

- Revenues
- Fossil Fuel costs
- Maintenance costs
- Labour costs
- Waste Disposal costs
- Chemicals and consumables costs
- Insurance
- Capital expenditures
- Working capital
- Decommissioning costs

The production costs per kWh of electricity are calculated by setting the NPV of the power plant to zero. This can be achieved by varying the kWh price until the revenues balance the costs over the whole life time of the power plant.

4.2.2 Criteria

The cash flow projection is made using the criteria as mentioned in the technical reference document. Criteria that need further explanation are discussed below:

Discount ratio and cost of debt

All cash flows will be discounted using a discount ratio of 10% and for illustrating sensitivity at 5%. These cash flows also include the debts made during the design, construction and commissioning. The interest rate for debt is equal to the discount rate and thus debt, or capital charges, can be treated as a negative cash flow.

Commissioning

A 3 month commissioning period will be allowed for all types of plant. In effect this means that during the first year the load factor of the plant is reduced by 25 %. For instance a coal fired power plant will operate at a load factor of 60% during the first year; by adding a commissioning period of 3 months, the load factor will be reduced to 45%.

Load factor

The load factors are specified in the technical reference document. The load factor affects the electricity production, consumption of all consumables, disposal of wastes and maintenance costs. It does *not* reduce the labour costs and insurance.

Decommissioning

The costs associated with shut down of the plant are taken as a percentage of the capital investment. However since these costs occur only once at the end of the lifetime of the power plant, the discounted cash flow is reduced to a minimum. As a result the decommissioning costs only comprise 0.1 to 0.2 % of the kWh price and are insignificant.

Maintenance

The Maintenance expenditures are 2% p.a. of the installed plant costs for gas and liquid handling plants and 4% for coal handling plants. Coal fired power plants are not completely coal handling, part of the plant is gas or liquid handling and thus has lower maintenance costs. The following table shows the coal handling share as a percentage of the installed plant cost.

Case	*C1wo*	*C1w*	*C2wo*	*C2w*
Coal handling share of installed plant cost	46%	36%	35%	28%

Table 4.3: Share of coal handling equipment in coal fired power plants

Confidence limits and Contingencies

For each of the power plants an allowance is made for estimating error and process unknowns / development. This allowance is set as a percentage of the overnight construction cost. As can be seen from the following table the confidence limits are quite low. This due to the fact that all techniques used are state of the art and the only uncertainty is the integration and scale of operation. Furthermore a contingency factor of 10% covers most of the risks.

Case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
confidence limit	0%	2%	5%	2%	0%	2%	1%	5%

Table 4.4: Confidence limits

Labour

The labour cost for one operator is set to 38000 US$/year. A percentage is added to the labour cost for indirect costs for supervision (20%) and administration + overhead (60%). The number of operators necessary for each plant are depicted in the following table:

case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
# operators	9	11	13	11	13	15	20	24

Table 4.5: Number of operators for all plants

Solids Disposal

The coal fired power plants produce ash which has to be disposed of. Conventional coal fired plants produce gypsum in the process of sulphur recovery whereas in coal gasifiers pure sulphur can be recovered. The low quality gypsum has to be disposed of at a cost whereas pure sulphur can be used to generate revenues. The total of costs for disposal of ash/slag, gypsum and revenues for the recovery of sulphur in coal fired power plants are:

case	*C1wo*	*C1w*	*C2wo*	*C2w*
Solids disposal costs (MUS$/year)	1.86	1.86	0.40	0.45

Table 4.6: Solids disposal cost for coal fired power plants

Consumables and Working capital

The consumables consist of the following components (depending on the type of plant):

- Limestone
- Chemicals for boiler water treatment
- Chemicals for waste water treatment
- Lubricants
- Potable water
- Gasification chemicals
- MEA / Selexol solution + additives
- Catalyst + internals

The yearly expenditures for consumables are presented in the following table:

case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
consumables (MUS$/y)	1.2	4.8	6.9	4.7	2.0	6.3	1.7	7.1

Table 4.7: Yearly expenditures on consumables

The working capital is sufficient storage of these materials for a period of 15 days. The coal fired power plants require also a fuel storage for 15 days as part of the working capital. The autothermal reformer in case G2w requires the purchase of catalyst and internals, these are not part of the capital investment.

Fuel Price

The fuel price will is set at 1.5 US$ / GJ for coal, and 2 US$ / GJ for natural gas. Chapter 5 of this report will show the cash flow results for a broad range of fuel prices.

4.2.3 Results

This chapter shows the results of the cash flow calculations at a discount rate of 10% and to illustrate sensitivity at a discount rate of 5%.

Discount rate of 10%

The resulting cash flow calculations for each case are presented in appendix 9. From these cash flows the following kWh prices result at a discount rate of 10%.

case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
kWh price (US$/kWh)	0.0216	0.0323	0.0344	0.0307	0.0374	0.0635	0.0478	0.0691
kWh price breakdown								
Cost of Fuel	59.3%	47.3%	43.3%	49.1%	31.7%	25.8%	24.4%	20.5%
Capital Expenditures	31.3%	39.8%	43.0%	38.1%	50.5%	54.7%	56.9%	59.5%
Other costs	9.5%	12.9%	13.6%	12.8%	17.9%	19.6%	18.7%	20.0%

Table 4.8: kWh price and kWh price breakdown at a 10% discount rate

The table also shows the price breakdown of the kWh price, the following chart shows these same figures:

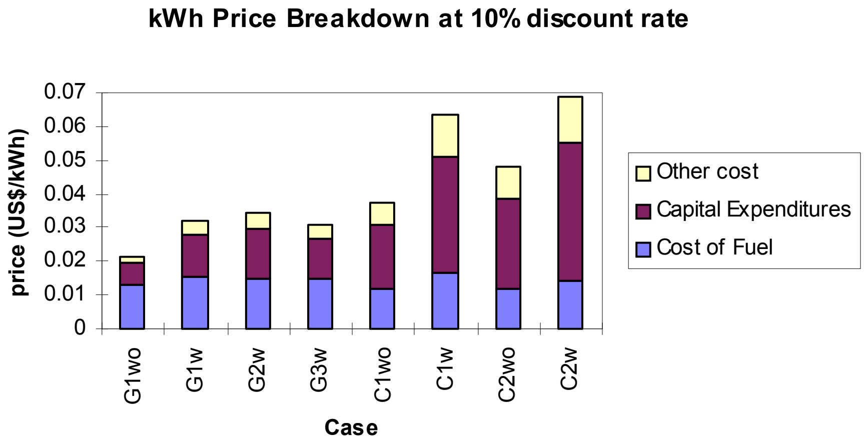

Figure 4.1: kWh price breakdown at a discount rate of 10%

Discount rate of 5%

The resulting cash flow calculations for each case are presented in appendix 10. From these cash flows the following kWh prices result at a discount rate of 5%.

case	*G1wo*	*G1w*	*G2w*	*G3w*	*C1wo*	*C1w*	*C2wo*	*C2w*
kWh price (US$/kWh)	0.0191	0.0275	0.0288	0.0263	0.0300	0.0498	0.0371	0.0528
kWh price breakdown								
Cost of Fuel	67.0%	55.5%	51.6%	57.2%	39.5%	32.9%	31.4%	26.8%
Capital Expenditures	22.2%	29.2%	32.1%	27.8%	38.3%	42.1%	44.5%	47.1%
Other costs	10.8%	15.3%	16.2%	15.0%	22.3%	25.0%	24.1%	26.2%

Table 4.9: kWh price and kWh price breakdown at a 5% discount rate

The table also shows the price breakdown of the kWh price, the following chart shows these same figures:

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Figure 4.2: kWh price breakdown at a discount rate of 5%

5. SENSITIVITY ANALYSIS

5.1 INTRODUCTION

The sensitivity analysis show how the power plants with and without CO_2 wash react to varying fuel prices. The effect of the fuel price on the kWh price will be shown in the following section. Furthermore the effect of CO_2 injection pressure on the plant efficiency will be shown.

5.2 FUEL PRICE SENSITIVITY

This section shows how fuel prices affect the kWh production price. The fuel prices vary between 1.00 and 4.50 US$ /GJ for natural gas and between 0.75 and 3.40 US$ / GJ for coal.

For this variation in fuel prices the production costs per kWh are calculated by levelling the NPV to zero as discussed in the previous chapter. The discount rate to be used is 10%.

The following graphs show the results of these calculations for gas fired power plants and coal fired power plants. The effect on the share of fuel costs in the kWh price is shown in two additional graphs.

Figure 2.2 shows that, at high coal prices, the gasifier with CO_2 removal (case C2w) becomes more attractive than the conventional coal fired plant with CO_2 removal (case C1w). This effect however is only marginal and occurs at coal prices well over 2.5 US$ / GJ.

Note that the graph shown in figure 2.4 has two lines on top of each other. Both cases C1w and C2wo have the same share of fuel costs in the kWh price.

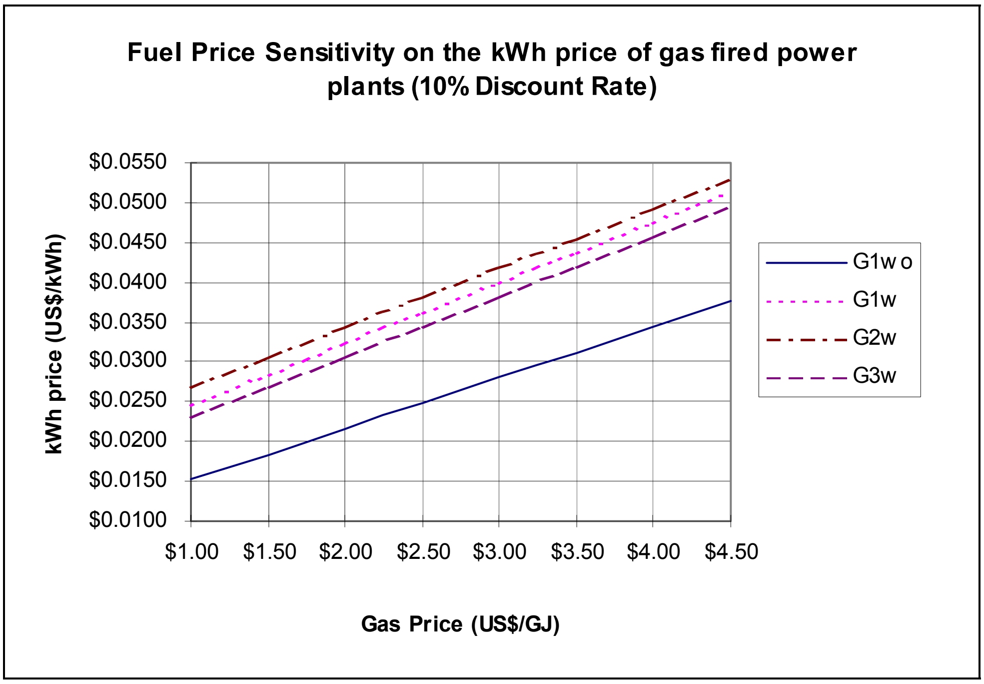

Figure 5.1: Gas price sensitivity on the kWh price

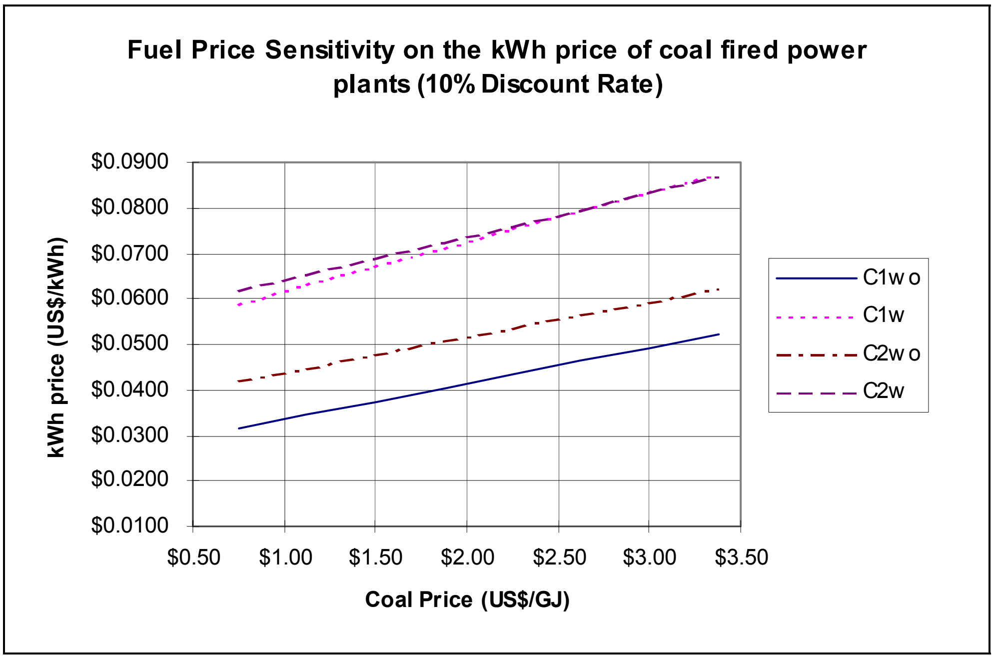

Figure 5.2: Coal price sensitivity on the kWh price

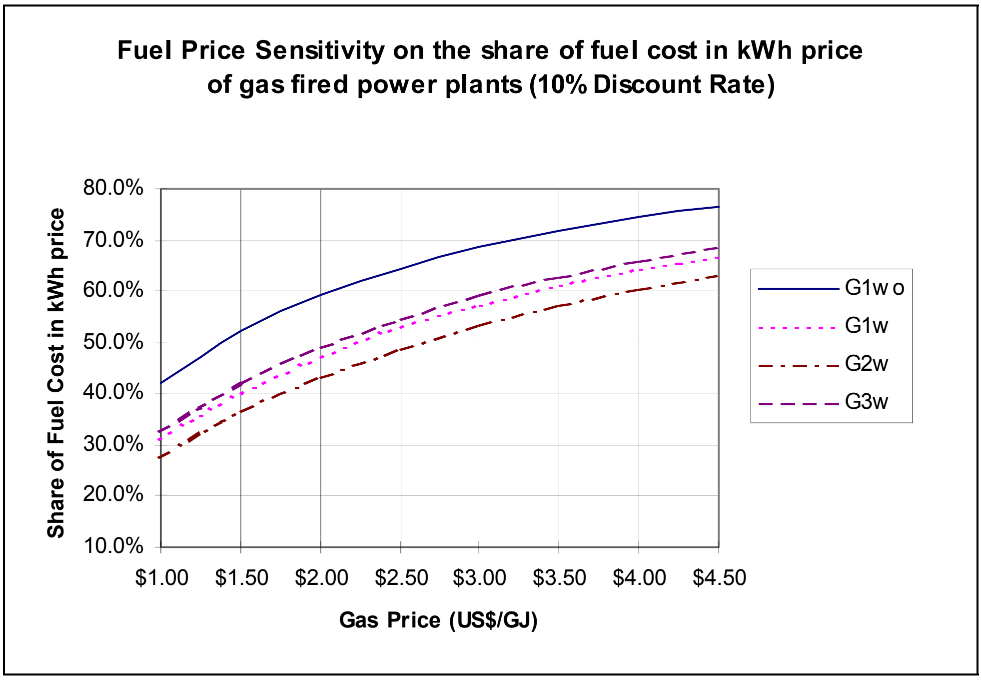

Figure 5.3: Share of fuel cost in the kWh price for varying gas price.

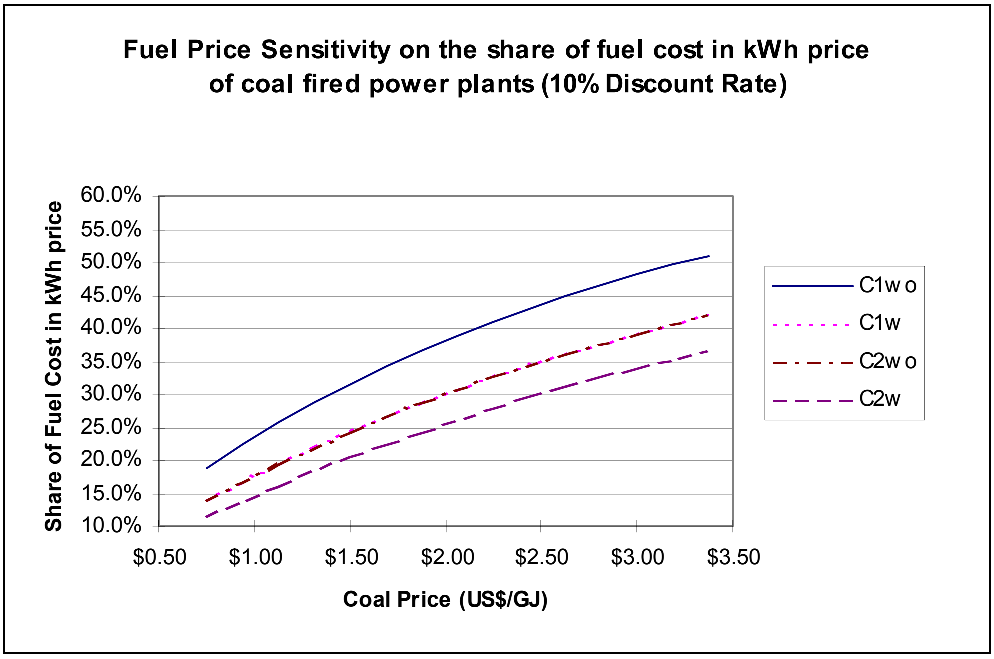

Figure 5.4: Share of fuel cost in the kWh price for varying coal price.

5.3 INJECTION PRESSURE PENALTY

This chapter shows the efficiency penalty of increasing the injection pressure of CO_2. A higher injection pressure demands more power input for the CO_2 compressor. The effect can be significant on the thermal efficiencies of the powerplant.

Case	G1w	G2w	G3w	C1w	C2w
Fuel Input (MWth)	1405.53	1695.77	1393.94	1098.18	1001.76
No Compression					
Net Power (MW)	691.53	847.58	519.32	397.41	408.24
Net Efficiency	49.20%	49.98%	37.26%	36.19%	40.75%
Compression to 60 bar					
Compression power (MW)	-24.31	-22.32	-23.91	-29.58	-20.77
Net Power (MW)	667.22	825.26	495.41	367.83	387.47
Net Efficiency	47.47%	48.67%	35.54%	33.49%	38.68%
Efficiency penalty	-1.73%	-1.32%	-1.72%	-2.69%	-2.07%
Compression to 80 bar					
Compression power (MW)	-26.41	-24.82	-25.98	-32.15	-23.10
Net Power (MW)	665.12	822.75	493.34	365.26	385.14
Net Efficiency	47.32%	48.52%	35.39%	33.26%	38.45%
Efficiency penalty	-1.88%	-1.46%	-1.86%	-2.93%	-2.31%
Compression to 110 bar					
Compression power (MW)	-28.86	-27.75	-28.39	-35.14	-25.82
Net Power (MW)	662.67	819.83	490.93	362.27	382.42
Net Efficiency	47.15%	48.35%	35.22%	32.99%	38.17%
Efficiency penalty	-2.05%	-1.64%	-2.04%	-3.20%	-2.58%

Table 5.5: Efficiency penalties from CO_2 injection pressures at 60, 80 and 110 bar.

The following graph illustrates these figures:

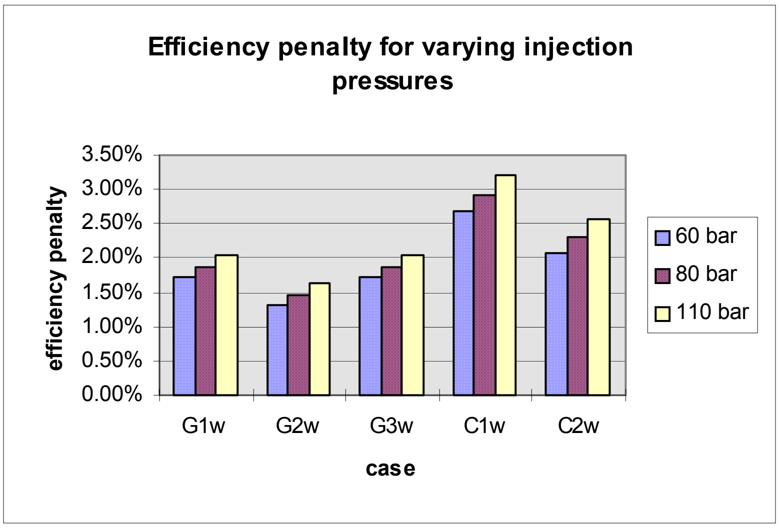

Figure 5.6: Efficiency penalties for CO_2 injection pressures of 60, 80 and 110 bar.

As can be seen clearly from this figure the case with the highest CO_2 production has the highest efficiency penalty.

MASS & ENERGY BALANCE

CASE

$G1_{W/O}$

IEA

THE ASSESSMENT OF LEADING TECHNOLOGY

OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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1. INTRODUCTION

This chapter shows the results of the Natural gas based power generation base case $G1_{w/o}$. This is a combined cycle without carbon dioxide removal. The combined cycle consists of:

- a gas turbine
- a triple pressure non fired natural circulation Heat Recovery Steam Generator (HRSG) with reheat
- a steam turbine with a HP, IP and LP condensing section

The plant design and selected components have been selected on the state of the art technology.

This combined cycle actually consists of two gas turbines and a HRSG, this gives a high power output of ca. 800 MWe, and allows room for steam extraction which is necessary in later cases with CO_2 removal. The power output according to the specifications should be 500 MWe, the gas turbine does not allow a flexibility to set a specified power output. A single gas turbine + HRSG delivers 400 MWe, this decreases further when the CO_2 removal unit extracts steam. To be closer to the specified power output two gas turbines were selected.

2. GAS TURBINE

Based on the requirement of designing a high power output plant (800 MWe for 2 gas turbines) a typical high efficiency gas turbine has been selected: the General Electric frame 9FA, with a dry low NO_x combustion system.

Type	GE PG9351(FA)
ISO Base Rating	255.6 MWe
Heat rate	9759 kJ/kWh
Pressure ratio	15.4
Mass flow	623.7 kg/s
Exhaust Temperature	609 °C

Table A1.1: ISO Base rating for the General Electric Frame 9FA (GT world 1998/1999)

This gas turbine can be considered as the current state of the art within its power range. Alternative gas turbines within this power range are:

- ABB GT 26
- Siemens V-94.3 A
- Mitsubishi M501 G

The performance of the gas turbine will vary with:

- ambient conditions
- inlet losses
- type of fuel

The presented performance figures are based on a new gas turbine. During operation degradation will occur, which will result in a decreased power output and an increased flue gas temperature.

For evaluation purposes the following starting points are applicable:

T ambient	9 °C
p ambient	1013 mbar
relative humidity	60%
height	0 m
inlet pressure drop	10 mbar
exhaust pressure drop	25 mbar

Table A1.2: Starting points

3. HRSG

The HRSG is a non fired triple pressure natural circulation boiler with single reheat. As the installation is considered to be a base load operating power plant the design is optimised with respect to the overall efficiency of the system. The higher overall efficiency will consequently result in a reduction of the CO_2 emission. Therefore the following design conditions have been selected:

In the design no additional facilities have been shown which are required for operation of the plant over the complete operating range such as de-superheating equipment.

The HRSG supplies steam at the following pressures and temperatures:

		Pressure	Temperature
HP:	High pressure	120 bar	560 °C
IP:	Intermediate pressure	27 bar	560 °C
LP:	Low pressure	4.6 bar	300 °C

Table A1.3: Steam pressures and temperatures

In order to achieve this the heat exchangers are set up according to the following table:

High pressure superheater	Steam temperature	560 °C
Medium pressure superheater/ reheater	Steam temperature	560 °C
Medium pressure superheater	Steam temperature	300 °C
Low pressure superheater	Steam temperature	300 °C
High pressure economiser	Degrees of subcooling	3 °C
Medium pressure economiser	Degrees of subcooling	3 °C
Low pressure economiser	Degrees of subcooling	3 °C
Water preheater	Exit temperature	95 °C
Evaporator (low, medium and high pressure)	Pinch delta temperature	8 °C

Table A1.4: Heat exchanger set-up

The condenser pressure is 0.04 bar. This is the saturation pressure at 29°C. This temperature is based on the sea water temperature of 12°C, the maximum allowed temperature rise of 7°C and a approach temperature of 3°C of the closed cooling water system. The closed cooling water system also supplies cooling water to other equipment in the installation, this flow is equal to 1000 m^3/hr. The sea water temperature and rise are specified in the technical reference document.

The design of the condensate heating/deaerator system has been based on a maximum deaerating efficiency in combination with a maximum thermal efficiency.
Therefore the deaerator system will operate at a pressure of 1.2 bar; 105 °C with a condensate feedwater temperature of 95 °C (To ensure a high deaerator efficiency the feedwater temperature shall be 10 °C below the deaerator temperature.) For deaeration and heating of the condensate LP steam will be used.
The condensate out of the condenser will be heated from 29° C to 95 °C by means of a closed water loop which is using the flue gas heat from the stack to preheat the condensate. Direct heating the condensate with flue gas is not possible because the condensate entry temperature is below the dew point of the flue gas. For modelling purposes this is achieved

not by a closed water loop but by mixing 95 °C water exiting the preheat section with 29 ° C water entering the preheat section in order to increase this temperature from 29 °C to a safe level of 70 °C.

List of remaining starting points:

- For calculation of the auxiliary power consumption all the pumps used have an overall efficiency of 75%.
- The steam turbine generator efficiency is 98%
- The cooling water consumption used by systems other than the condenser is set at 1000 m^3/hr
- Blow down is set at 0%
- Minor steam losses, such as the ejector steam and gland steam are neglected.

4. STEAM TURBINE

The steam turbine is split up in the following sections:

- a HP section which is supplied with steam from the HP superheater
- a MP section which is supplied with a mixture of steam from the MP superheater and steam from the HP turbine which is reheated in the reheat section
- a LP section which is supplied with a mixture of steam from the LP superheater and steam from the MP turbine section

The steam turbine has the following characteristics:

Section	*Overall isentropic efficiency*	*Inlet pressure*	*Inlet temperature*	*Outlet pressure*	*Outlet temperature*
High pressure	86.5 %	120 bar	560 °C	29 bar	354 °C
Intermediate pressure	88.0 %	27 bar	560 °C	4.6 bar	319 °C
Low pressure	89.5 %	4.6 bar	317 °C	0.04 bar	29 °C

Table A1.5: Steam turbine characteristics

5. ENERGY BALANCE

The resulting energy balance becomes:

Energy balance		
Fuel Consumption LHV	1405.53 MW	
Gas Turbine	508.58 MW	
GT Shaft power		*517.88 MW*
GT remaining losses		*-3.08 MW*
GT Generator losses		*-6.21 MW*
Net GT power		*508.58 MW*
Steam Turbine	294.06 MW	
ST Shaft power		*300.06 MW*
ST Generator losses		*-6.00 MW*
ST Generator output		*294.06 MW*
Balance of Plant losses	-12.78 MW	
Boiler feedwater pumps		*-4.48 MW*
Cooling water pumps		*-5.30 MW*
Remaining losses		*-3.00 MW*
BOP losses		*-12.78 MW*
Total Plant net power	789.86 MW	
Net efficiency	56.19%	

Table A1.6: Results energy balance

6. STREAM REPORTS

Using the data specified in the technical reference document simulations in GateCycle produced the following stream report. The stream numbers correspond to the numbers depicted in the figure at the end of this section.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
T (C)	612.2	88.3	108.6	156.5	235.3	327.8	327.8	560.0	353.8
p (bar)	1.01	1.01	131.00	131.00	130.50	130.00	125.00	120.00	28.99
m (kg/s)	1287	1287	160	160	160	160	160	160	160
h (kJ/kg)	660.9	76.4	465.0	667.8	1017.1	1510.7	2678.4	3505.0	3128.6
quality			0.0	0.0	0.0	0.0	1.0	1.0	1.0

Stream	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
T (C)	105.9	156.5	235.3	232.9	300.0	560.0	319.1	105.1	156.5
p (bar)	32.99	32.99	32.49	29.49	28.99	27.00	4.60	6.10	6.10
m (kg/s)	24	24	24	24	24	184	184	22	22
h (kJ/kg)	446.3	661.9	1015.3	2802.3	2998.2	3593.4	3105.1	441.0	660.2
quality	0.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0	0.0

Stream	*19*	*20*	*21*	*22*	*23*	*24*	*25*	*26*	*27*
T (C)	152.6	300.0	29.0	29.0	95.0	22.0	15.0	12.0	19.1
p (bar)	5.10	4.60	0.04	0.04	1.20	1.50	2.00	2.00	1.00
m (kg/s)	22	22	204	204	204	15892	15892	15830	15830
h (kJ/kg)	2748.4	3065.7	2364.7	121.4	398.0	92.3	63.1	50.6	80.1
quality	1.0	1.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0

Table A1.7: Stream report

7. EXHAUST GAS CONSTITUENTS

The following Table shows the compositions of combustion air entering the gas turbines and of the flue gas leaving the stack. The composition is in molar percentage.

Component	*Air*	*Flue gas*
Ar	0.92 %	0.89 %
O_2	20.77 %	12.28 %
N_2	77.40 %	74.51 %
H_2O	0.87 %	8.21 %
CO_2	0.03 %	4.12 %

Table A1.8: Air and Flue Gas composition in molar %

The fuel gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves. The composition in molar percentage is as follows:

Component	
Methane	83.9 %
Ethane	9.2 %
Propane	3.3 %
Butane +	1.4 %
Carbon-dioxide	1.8 %
Nitrogen	0.4 %
Sulphur (as H_2S)	4 mg/Nm^3
Lower Heating Value	46.899 MJ/kg

Table A1.9: Fuel gas composition in molar % and LHV

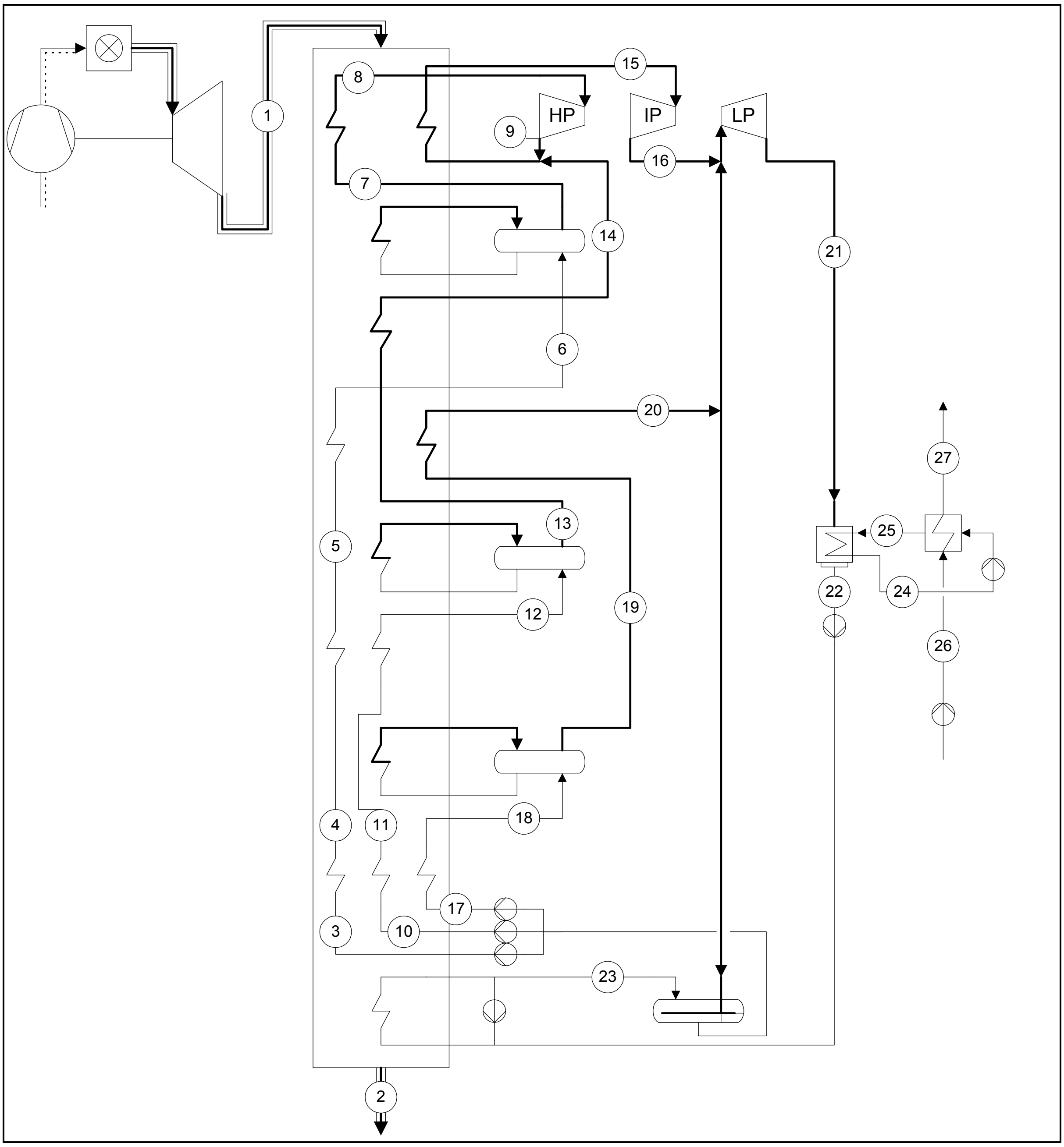
HP
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Figure A1.1

MASS & ENERGY BALANCE

CASE

$G1_W$

IEA

THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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1. INTRODUCTION

This chapter shows the results of the Natural gas based power generation case $G1_w$. This is a combined cycle with carbon dioxide removal. The design used in this case is similar to the combined cycle case $G1_{wo}$ with the addition of a CO_2 recovery unit.

For design specifications of the Combined Cycle reference is made to case $G1_{wo}$. The following components are added for the CO_2 recovery unit:
- flue gas cooler
- flue gas fan
- Absorber
- CO_2 compressor
- steam extraction points

2. CO_2 RECOVERY UNIT

2.1 FLUE GAS COOLING

The flue gas temperature entering the CO_2 recovery unit can not be higher than 40°C; therefore a heat exchanger cools down the flue gases from 109 °C to 40 °C. A heat exchanger made of a fluorine plastic material allows for these temperatures below the dew point of the flue gasses. In the cooling process approximately 38 kg/s of water condenses, this can be treated as ordinary sewage water.
The heat recovered from the flue gases can be used to heat up the stack gases leaving the CO_2 absorber.

2.2 FLUE GAS FAN

The pressure drop over the CO_2 absorber is approximately 40 mbar. A forced draught fan leads the flue gases from the HRSG through the CO_2 absorber and the stack.

2.3 ABSORBER

The CO_2 recovery unit consists of an absorber/stripper combination using monoethanolamine (MEA) as an absorbent. The absorber is equipped as a conventional column with trays. Using a gas-absorption membrane is theoretically possible, applications however have so far only be realised on a small scale. The membranes should result in a lower energy consumption and therefore a higher overall efficiency.

The stripper requires a heat duty to remove the CO_2 from the MEA solution. A reboiler condenses LP steam extracted from the HRSG to supply the heat duty to the stripper.

In the absorber and the stripper some of the MEA solution is lost. The flue gas stream leaving the absorber and CO_2 leaving the stripper still contains a certain amount of MEA solution. A make-up takes account of these losses.

2.4 CO_2 COMPRESSOR

The removed CO_2 will be compressed to 110 bar and liquefied before leaving the plant by pipeline and then stored by injecting it into a deep saline reservoir. Two compressors will be used with a total of 4 stages, the compressors will be inter-cooled and a flash vessel removes condensed water in-between the compressors.. Table 1 shows the basic assumptions for the calculation of the required compressor power and cooling water flow. The closed cooling water system of the combined cycle supplies the cooling water for the compressors. The inter-coolers decrease the temperature of the gas flow to 35 °C.

Stage	*1*	*2*	*3*	*4*
pressure ratio	4.2	2.8	3.8	110 bar exit
isentropic efficiency	78 %	74 %	75 %	58 %

Table A2.1: CO2 compressor properties

2.5 STEAM EXTRACTION POINTS

The stripper requires a heat duty to remove the CO_2 from the MEA solution. A reboiler condenses LP steam extracted from the HRSG to supply the heat duty to the stripper. LP steam is extracted from the HRSG at 4.6 bar and 317°C and condensed in the reboiler to 4.6 bar and 125 °C. The steam is extracted from the main steam flow entering the LP turbine. The condensate returning from the reboiler is injected into the deaerator.

3. ENERGY BALANCE

The resulting energy balance becomes:

Energy balance		
Fuel Consumption LHV	1405.53 MW	
Gas Turbine	508.57 MW	
GT Shaft power		*517.87 MW*
GT remaining losses		*-3.08 MW*
GT Generator losses		*-6.21 MW*
Net GT power		*508.57 MW*
Steam Turbine	205.37 MW	
ST Shaft power		*209.56 MW*
ST Generator losses		*-4.19 MW*
ST Generator output		*205.37 MW*
Balance of Plant losses	-8.92 MW	
Boiler feedwater pumps		*-4.38 MW*
Cooling water pumps		*-2.45 MW*
Remaining losses		*-2.09 MW*
BOP losses		*-8.92 MW*
CO_2 recovery unit	-42.35 MW	
flue gas fan		*-5.26 MW*
Absorber recycle pump		*-5.50 MW*
Compressor		*-28.08 MW*
Add. Cooling water pumps		*-3.51 MW*
CO_2 recovery penalty		*-42.35 MW*
Total Plant net power	662.67 MW	
Net efficiency	47.15 %	

Table A2.2: Results energy balance

The CO_2 recovery unit not only requires power and steam extraction for the unit itself but also requires an amount of cooling water that increases the power demand of the cooling water pumps. The cooling water is used for cooling down the flue gases to 32 °C, the CO_2 compressor and the CO_2 absorber unit.

4. STREAM REPORT

Using the data specified in the technical reference document simulations in GateCycle produced the following stream report. The stream numbers correspond to the numbers depicted in the figure at the end of this section.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	612.2	113.2	28.0	28.0	32.1	88.3	35.0	38.2	34.7	111.2
p (bar)	1.01	1.01	1.01	1.01	1.05	1.50	110.00	1.01	1.01	1.60
m (kg/s)	1286.5	1286.5	1286.5	1248.6	1248.6	91.7	70.0	1197.2	2905.4	2813.7
h (kJ/kg)	660.9	102.7	13.0	12.7	16.9	-	-	-	-	-
quality	-	-	-	-	-	-	-	-	-	-

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	108.6	156.5	235.3	327.8	327.8	560.0	353.8	105.9	156.5	235.3
p (bar)	131.00	131.00	130.50	130.00	125.00	120.00	28.99	32.99	32.99	32.49
m (kg/s)	160.1	160.1	160.1	160.1	160.1	160.1	160.1	24.1	24.1	24.1
h (kJ/kg)	465.0	667.8	1017.1	1510.7	2678.4	3505.0	3128.6	446.3	661.9	1015.3
quality	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.00	0.00	0.00

Stream	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
T (C)	232.9	300.0	560.0	319.1	105.1	156.5	152.6	300.0	29.0	29.0
p (bar)	29.49	28.99	27.00	4.60	6.10	6.10	5.10	4.60	0.04	0.04
m (kg/s)	24.1	24.1	184.2	184.2	22.4	22.4	22.4	22.4	80.6	80.6
h (kJ/kg)	2802.3	2998.2	3593.4	3105.1	441.0	660.2	2748.4	3065.7	2364.7	121.4
quality	1.00	1.00	1.00	1.00	0.00	0.00	1.00	1.00	0.92	0.00

Stream	*31*	*32*	*33*	*34*	*35*	*36*	*37*
T (C)	95.0	317.0	111.0	12.0	19.0	15.0	22.0
p (bar)	1.20	4.60	3.60	2.00	1.00	2.00	1.50
m (kg/s)	80.6	126.0	126.0	13276.3	13276.3	17730.3	17730.3
h (kJ/kg)	398.0	3100.8	465.7	50.6	79.8	63.1	92.4
quality	0.00	1.00	0.00	0.00	0.00	0.00	0.00

Table A2.3: Stream report

5. EXHAUST GAS CONSTITUENTS

The following table shows the compositions of combustion air entering the gas turbines and of the flue gas leaving the HRSG and proceeding through the CO_2 recovery unit. The stream numbers correspond to the numbers in the scheme at the end of this section. The composition is in molar percentage.

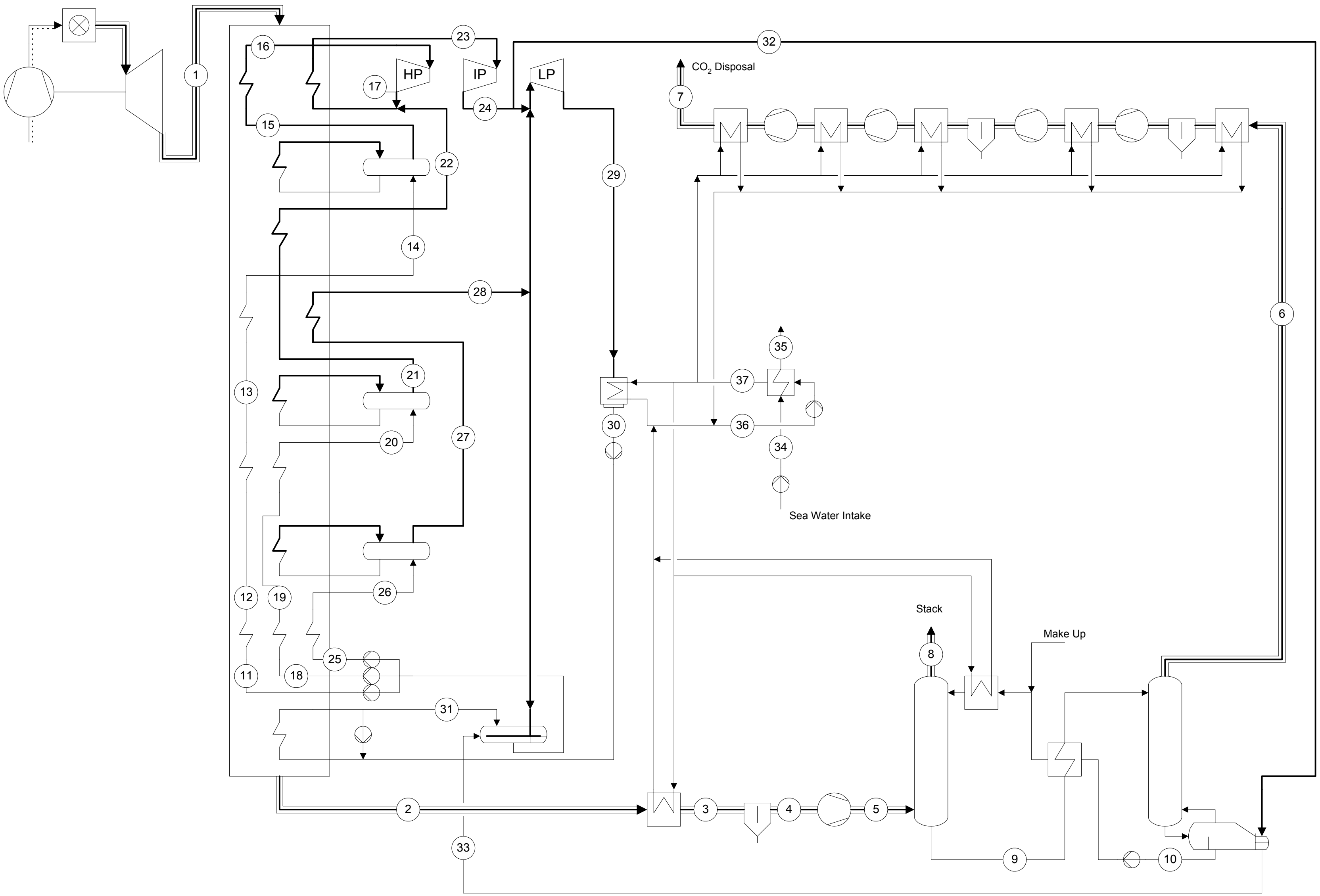
Component	*Air*	*2*	*4*	*6*	*7*	*8*	*9*	*10*
Ar	0.92	0.89	0.93	0.00	0.00	0.95	-	-
O_2	20.77	12.28	12.87	0.03	0.05	13.04	-	-
N_2	77.40	74.51	78.14	0.07	0.13	79.18	-	-
H_2O	0.87	8.21	3.73	43.18	0.32	6.17	92.49	93.49
CO_2	0.03	4.12	4.32	56.72	99.50	0.66	2.61	1.50
MEA	-	-	-	0.00	-	-	4.91	5.01

Table A2.4: Air and Gas compositions in molar %

The fuel gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves. The composition in molar percentage is as follows:

Component	
Methane	83.9 %
Ethane	9.2 %
Propane	3.3 %
Butane +	1.4 %
Carbon-dioxide	1.8 %
Nitrogen	0.4 %
Sulphur (as H_2S)	4 mg/Nm^3
Lower Heating Value	46.899 MJ/kg

Table A2.5: Fuel gas composition in molar % and LHV



HP
IP
LP
CO_2 Disposal
Sea Water Intake
Stack
Make Up
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10
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Figure A2.1

MASS & ENERGY BALANCE
CASE
$G2_W$

IEA
THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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1. INTRODUCTION

This chapter shows the results of the Natural gas based power generation case $G2_w$. This is a combined cycle with an autothermal reformer and carbon dioxide removal. The autothermal reformer converts the natural gas to a syngas consisting of CO and H_2. A two step shift reactor shifts the CO to H_2 and CO_2. A physical solvent process removes the CO_2 from the syngas. The combined cycle consists of a gas turbine, a Heat Recovery Steam Generator (HRSG) and a CO_2 recovery unit.

The design of the GT and HRSG were made according to the natural gas fired combined cycle (CC) case $G1_{w/o}$. Due to the integration of the autothermal reactor, shift reactors and the CO_2 absorber some modifications are necessary. Only the modifications will be discussed in this mass and energy balance. For details on the design of the CC reference is made to case $G1_w$. The combined cycle consists of two trains each based upon a General Electric Frame 9FA gas turbine.

2. AUTOTHERMAL REFORMER

The autothermal reformer converts natural gas to a syngas containing CO and H_2 using a catalyst. Steam (29 bar) and oxygen have to be added to enable the conversion. Steam is derived from the exhaust of the HP steam turbine, oxygen is produced by an air separation unit, ASU. The amount of steam that is added is not only necessary for the reforming reactions but also for the shift reactions taking place in the double shift reactor.

The syngas leaves the reformer at a temperature of 1050 °C. Heat is recovered from the syngas by producing HP steam in an evaporator. This cools down the syngas to a temperature of 500 °C. A heat exchanger than further cools down the syngas to a temperature of 382 °C by heating up the fuel gas entering the reformer. The syngas can than enter the double shift reactor.

3. SHIFT REACTOR AND CO_2 RECOVERY

After the syngas is cooled down it enters the double shift reactor. The double shift reactor shifts the CO/H_2 syngas produced by the gasifier in two separate steps into a mixture of H_2 and CO_2 according to the following reaction:

$$CO + H_2O \leftrightarrow H_2 + CO_2$$

Steam necessary for the shift reaction is already added in the autothermal reformer. The two shift reactors are exothermic and heat can be recovered from the reaction. The recovered heat is integrated into the cycle according to the following table.

Heat recovered from the:	*Cycle integration:*	*MWth (approx.)*
First Shift reactor	heating of fuel for gas turbine	44 MWth
	IP evaporator	13 MWth
	LP evaporator	22 MWth
	heating of water for syngas saturation	17 MWth
Second shift reactor	heating of economiser water	57 MWth
	cooling water loss	2 MWth

Table A3.1: Heat recovery shift reactors

The H_2 / CO_2 mixture then enters a physical solvent process where a selexol solution physically removes the CO_2 from the mixture. The CO_2 is recovered from the solution by reducing the pressure in two steps. The first step releases CO_2 at 6.3 bar, the second at 1.5 bar. The CO_2 than enters the CO_2 compressor at these two pressure levels to reduce the amount of work necessary to compress the CO_2 to 110 bar. For the design of the compressor station reference is made to case $G1_w$.
In the selexol recovery process, energy is required for pumping the selexol. A hydraulic turbine recovers some of the energy by reducing the pressure of the selexol.

The H_2 rich fuel gas is mixed with the N_2 produced by the ASU to enhance cycle performance. The gas mixture than proceeds through the saturator where water is added to enhance the performance of the gas turbine and reduce NO_x emissions. The gas is combusted in the GE Frame 9 FA gas turbine.

4. GAS TURBINE

The Gas turbine is a modified GE frame 9. The following modifications are required for this gas turbine:

- The compressor to enable the export of compressed air to the oxygen plant
- The fuel nozzle to allow for a higher mass flow of the low LHV syngas fuel.
- The combustor should be able to combust a H_2 rich gas without excessive NOx emissions (limits are stated in the technical reference document)

- The expander turbine should allow the expansion of flue gas with a high H_2O content due to the combustion of the H_2 rich syngas.

The combustion of a low LHV syngas fuel and the extraction of air from the compressor is modelled in such a way that the fluegas flow and temperature entering the turbine expander are similar compared to a natural gas fired gas turbine.

The higher combustion value of the H_2 rich gas (compared to case $C2_{w/o}$) reduces the amount of air extracted from the gas turbine compressor: A higher combustion value reduces the fuel flow in the combustor therefore less air has to be extracted from the compressor to establish a flow through the turbine that is similar to the natural gas operation mode of the gas turbine.

5. HRSG

To enable the reforming and shift reactions to take place IP steam will be extracted from the HP steam turbine section exhaust and injected into the reformer. This steam is mixed in the gas flow and additional make up flow is necessary to compensate for this loss.

The exothermic autothermal reformer and shift reactors supply additional heat duty to the steam cycle. The hot stream out of the reformer reactor provides heat to evaporate HP water (158 MWth). The first shift reactor provides heat to evaporate IP water (13 MWth) and LP water (22 MWth). The second shift reactor provides heat (57 MWth) to heat up the condensate feedwater entering the HRSG.

6. AIR SEPARATION UNIT

The design of the air separation unit does not differ from the ASU in case $C2_{w/o}$. The amount of air that is extracted from the gas turbine compressor is however not enough to fully supply the ASU with pressurised air. Therefore an additional air compressor will be installed to supply the remainder of pressurised air.

The amount of air that is extracted from the gas turbine compressor is lower than in case $C2_{w/o}$ due to the high heating value of the H_2 rich gas. This is explained in paragraph 3, covering the gas turbine.

7. ENERGY BALANCE

Energy Balance		
Fuel Consumption LHV	1695.77 MW	
Gas Turbine	574.05 MW	
GT Shaft power		*584.14 MW*
GT remaining losses		*-3.08 MW*
GT Generator losses		*-7.01 MW*
Net GT power		*574.05 MW*
Steam turbine	361.19 MW	
ST Shaft power		*368.56 MW*
ST Generator losses		*-7.37 MW*
ST Generator output		*361.19 MW*
Balance of plant losses	-20.04 MW	
Boiler feedwater pumps		*-6.53 MW*
Cooling water pumps		*-9.82 MW*
Remaining losses		*-3.69 MW*
BOP losses		*-20.04 MW*
Air Separation Unit	-62.92 MW	
Air compressor power		*-8.07 MW*
Oxygen compressor		*-14.44 MW*
Nitrogen compressor		*-40.41 MW*
ASU power loss		*-62.92 MW*
CO2 recovery unit	-32.44	
Absorber recycle pump		*-8.62 MW*
Hydraulic turbine		*3.88 MW*
CO2 compressor		*-27.07 MW*
Cooling water pumps		*-0.63 MW*
CO2 recovery losses		*-32.44 MW*
Total plant net power	819.83 MW	
Efficiency	48.35%	

Table A3.2: Results energy balance

8. STREAM REPORT

Using the data specified in the technical reference document simulations in GateCycle produced the following stream report. The stream numbers correspond to the numbers depicted in figure at the end of this section.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	9.0	610.2	95.3	399.0	350.7	220.0	119.0	215.0	12.0	351.9
p (bar)	1.01	1.01	1.01	15.45	11.00	11.00	11.00	35.80	36.30	29.00
m (kg/s)	1256.1	1287.0	1287.0	131.0	173.2	173.2	173.2	41.2	36.2	34.9
h (kJ/kg)	2.3	902.5	309.1	405.1	353.6	216.8	113.5	184.2	-	3121.4
quality										1.00

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	1050.0	500.0	382.2	453.7	291.2	243.0	163.0	100.0	206.4	44.0
p (bar)	25.50	25.00	24.50	23.50	23.00	22.50	22.00	21.50	21.00	20.50
m (kg/s)	112.3	112.3	112.3	112.3	112.3	112.3	112.3	112.3	112.3	112.3
h (kJ/kg)	-	-	-	-	-	-	-	-	-	-
quality										

Stream	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
T (C)	37.0	44.9	120.0	77.8	93.6	166.0	300.0	1331.0	20.0	20.0
p (bar)	20.00	20.00	22.00	20.00	19.50	19.50	19.50	14.91	6.30	1.50
m (kg/s)	106.6	23.4	130.8	154.2	162.0	162.0	162.0	-	45.7	37.4
h (kJ/kg)	-	265.8	108.6	132.5	284.3	430.5	703.6	1869.2	-	-
quality										

Stream	*31*	*32*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*40*
T (C)	35.0	108.8	156.5	235.4	327.9	327.9	327.9	328.0	560.0	354.9
p (bar)	110.00	131.00	131.00	130.50	130.00	125.00	130.00	125.00	120.00	29.00
m (kg/s)	83.1	237.4	237.4	237.4	101.4	101.4	136.0	136.0	237.4	237.4
h (kJ/kg)	16.5	465.4	667.5	1016.8	1509.7	2673.4	1509.7	2674.3	3505.8	3128.6
quality		0.00	0.00	0.00	0.00	1.00	0.00	1.00	1.00	1.00

Table A3.3: Stream report

Mass & Energy Balance $G2_w$

Stream	*41*	*42*	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*
T (C)	106.1	156.5	235.4	233.0	235.4	233.0	300.0	560.0	319.6	105.3
p (bar)	33.00	33.00	32.50	29.50	32.50	29.50	29.00	27.00	4.60	6.10
m (kg/s)	13.7	13.7	6.3	6.3	7.3	7.3	13.7	216.1	216.1	23.5
h (kJ/kg)	446.6	661.5	1015.0	2803.7	1015.0	2803.8	2996.1	3593.9	3105.1	441.3
quality	0.00	0.00	0.00	1.00	0.00	1.00	1.00	1.00	1.00	0.00

Stream	*51*	*52*	*53*	*54*	*55*	*56*	*57*	*58*	*59*	*60*
T (C)	156.5	152.6	156.5	153.0	300.0	29.0	27.2	62.8	95.0	12.0
p (bar)	6.10	5.10	6.10	5.10	4.60	0.04	2.30	1.70	1.20	2.00
m (kg/s)	13.1	13.1	10.4	10.4	23.5	235.4	270.3	270.3	270.3	29567.4
h (kJ/kg)	659.9	2749.1	659.9	2750.0	3064.8	2364.7	113.9	262.4	397.5	50.1
quality	0.00	1.00	0.00	1.00	1.00	0.92	0.00	0.00	0.00	0.00

Stream	*61*	*62*	*63*
T (C)	19.0	22.0	15.0
p (bar)	1.00	1.50	2.00
m (kg/s)	29567.4	29332.5	29332.5
h (kJ/kg)	79.4	92.0	62.7
quality	0.00	0.00	0.00

Table A3.3: Stream report (cont.)

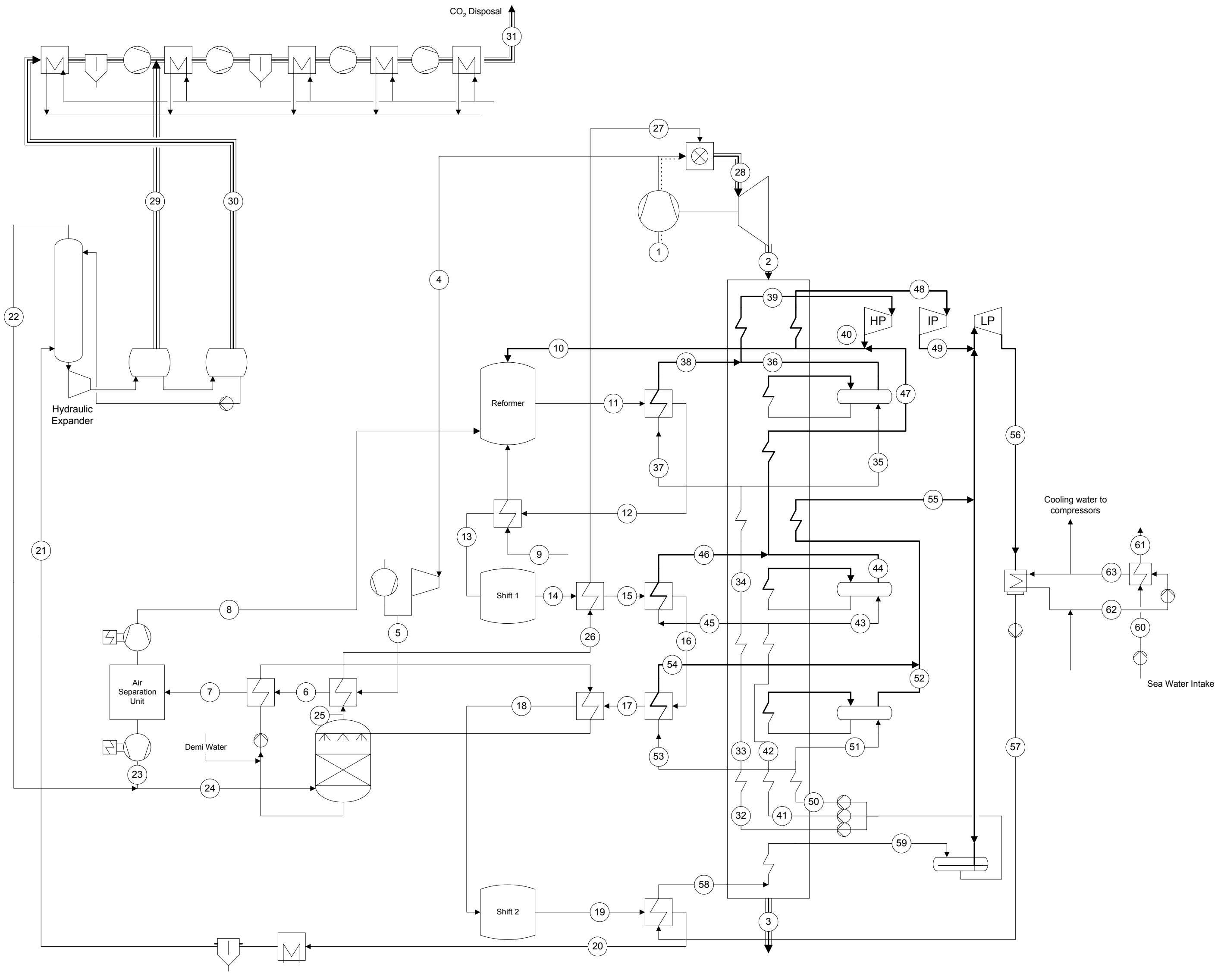
9. GAS CONSTITUENTS

The following table shows the syngas and exhaust gas composition in mole fractions.

Component	1	2	8	9	11	14	19	21
Ar	0.93	0.77	3.50	0.00	0.61	0.61	0.61	0.64
H_2	-	-	-	0.00	49.47	59.09	67.71	70.44
O_2	20.83	10.99	95.00	-	-	-	-	-
N_2	77.64	74.17	1.5	0.40	0.27	0.27	0.27	0.28
H_2O	5.66	13.33	0.00	0.00	22.46	12.84	4.22	0.36
CO	-	-	-	0.00	21.61	11.98	3.37	3.50
CO_2	0.03	0.75	0.00	1.80	5.21	14.83	23.45	24.40
CH_x	-	-	-	97.80	0.37	0.37	0.37	0.39

Component	22	23	24	27	28	29	30	31
Ar	0.84	0.00	0.47	0.45	0.75	0.00	0.00	0.00
H_2	92.68	-	52.06	50.03	-	0.62	0.62	0.62
O_2	-	0.70	0.31	0.30	10.16	-	-	-
N_2	0.37	99.30	43.73	42.03	73.87	0.00	0.00	0.00
H_2O	0.42	-	0.24	5.00	14.40	0.18	0.18	0.18
CO	4.54	-	2.55	2.45	0.00	0.22	0.22	0.22
CO_2	0.64	-	0.36	0.35	0.81	98.98	98.98	98.98
CH_x	0.51	-	0.29	0.28	-	0.00	0.00	0.00

Table A3.4: Gas compositions



CO_2 Disposal
Hydraulic Expander
Reformer
Shift 1
Shift 2
Air Separation Unit
Demi Water
HP
IP
LP
Cooling water to compressors
Sea Water Intake

Figure A3.1

MASS & ENERGY BALANCE
CASE
$G3_W$

IEA
THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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1. INTRODUCTION

This chapter shows the results of the Natural gas based power generation case $G3_w$. This is a combined cycle with partial recycling of the flue gas and carbon dioxide removal. The combined cycle consists of a gas turbine, a Heat Recovery Steam Generator (HRSG) and a CO_2 recovery plant. The design of the combined cycle itself is based on the assumptions made in case G1wo. The CO_2 recovery unit design is made according to case G1w.

Recycling 50 % of the flue gasses in to the entry of the gas turbines doubles the concentration of CO_2 in the exhaust gasses. This facilitates the removal of CO_2 from the flue gasses and reduces the duty needed for the CO_2 absorber.

2. RECYCLE

Recycling the flue gas into the requires the addition of the following major components:

- flue gas cooler
- flue gas damper
- recycle gas fan

The flue gas exiting the HRSG is cooled down to 32 °C by means of a heat exchanger made of fluorine plastic. The cooled flue gas flows into a flue gas damper which splits the flue gas in two equal flows. A recycle gas fan forces the part of the flue gas into a mixing section where this flow is mixed with air.

Gas Turbine considerations

When Firing the gas turbine with the mixture of flue gas and air special attention has to be paid to the flame stabilisation. The oxygen level of the combustion air drops down to 13 vol. % when mixing the flue gas with air (the oxygen level of normal air is 21 vol. %). This low Oxygen level enhances the chance of flame out in the combustion chamber.

An oxygen level of 15 vol. % is acceptable for modern gas turbines; it is expected that with some modifications of the combustion chamber, the minimum required oxygen level could be as low as 13 vol. %.

3. ENERGY BALANCE

The resulting energy balance becomes:

Energy balance		
Fuel Consumption LHV	1393.94 MW	
Gas Turbine	490.93 MW	
GT Shaft power		*500.01 MW*
GT remaining losses		*-3.08 MW*
GT Generator losses		*-6.00 MW*
Net GT power		*490.93 MW*
Steam Turbine	225.38 MW	
ST Shaft power		*229.98 MW*
ST Generator losses		*-4.60 MW*
ST Generator output		*225.38 MW*
Recycle Flow Fan	-1.26 MW	
Balance of Plant losses	-10.76 MW	
Boiler feedwater pumps		*-4.63 MW*
Cooling water pumps		*-3.83 MW*
Remaining losses		*-2.30 MW*
BOP losses		*-10.76 MW*
CO_2 recovery unit	-38.49 MW	
flue gas fan		*-2.50 MW*
Absorber recycle pump		*-4.93 MW*
Compressor		*-27.63 MW*
Add. Cooling water pumps		*-3.43 MW*
CO_2 recovery penalty		*-38.49 MW*
Total Plant net power	665.80 MW	
Net efficiency	47.76 %	

Table A4.1: Results energy balance

The penalties for recycling of the flue gases are a reduction of the gas turbine power, the power required by the recycle flow fan and an increase of the cooling water flow necessary for cooling the flue gasses to 32 °C. An increase in steam turbine power compromises this reduction in power.

The CO_2 recovery unit uses the cooled flue gas, this gives a reduction of the power required for the cooling water pumps, compared to case G1w, the case without recycle.

4. STREAM REPORT

Using the data specified in the technical reference document simulations in GateCycle produced the following stream report. The stream numbers correspond to the numbers depicted in the figure at the end of this section.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	630.1	108.1	28.0	28.0	32.1	87.5	35	39.1	37.2	111.1
p (bar)	1.01	1.01	1.01	1.01	1.05	1.50	110.00	1.01	1.04	1.60
m (kg/s)	1255.7	1255.7	1255.7	1206.5	603.3	89.2	68.890	543.2	2611.3	2522.1
h (kJ/kg)	690.7	98.0	13.1	12.7	16.8	-	-	-	-	-
quality	-	-	-	-	-	-	-	-	-	-

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	108.6	156.5	235.3	327.8	327.8	560.0	353.8	105.9	156.5	235.3
p (bar)	131.00	131.00	130.50	130.00	125.00	120.00	28.99	32.99	32.99	32.49
m (kg/s)	170.3	170.3	170.3	170.3	170.3	170.3	170.3	21.1	21.1	21.1
h (kJ/kg)	465.0	667.8	1017.1	1510.7	2678.4	3505.0	3128.6	446.3	661.9	1015.3
quality	0.00	0.00	0.00	0.00	1.00	1.00	1.00	0.00	0.00	0.00

Stream	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
T (C)	232.9	300.0	560.0	319.1	105.1	156.5	152.6	300.0	29.0	29.0
p (bar)	29.49	28.99	27.00	4.60	6.10	6.10	5.10	4.60	0.04	0.04
m (kg/s)	21.1	21.1	191.4	191.4	20.5	20.5	20.5	20.5	98.3	98.3
h (kJ/kg)	2802.3	2998.2	3593.4	3105.1	441.0	660.2	2748.4	3065.7	2365.0	121.4
quality	1.00	1.00	1.00	1.00	0.00	0.00	1.00	1.00	0.92	0.00

Stream	*31*	*32*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*40*
T (C)	95.0	317.3	113.0	12.0	19.0	15.0	22.0	28.0	30.1	22.7
p (bar)	1.20	4.60	3.60	2.00	1.00	2.00	1.50	1.01	1.03	1.01
m (kg/s)	98.3	113.6	113.6	18837.3	18837.3	18696.7	18696.7	603.2	603.3	1225.9
h (kJ/kg)	398.0	3101.3	474.1	50.6	79.8	63.1	92.3	12.7	14.8	7.3
quality	0.00	1.00	0.00	0.00	0.00	0.00	0.00	-	-	-

Table A4.2: Stream report

5. EXHAUST GAS CONSTITUENTS

The following table shows the compositions of combustion air that is being mixed with the recycle flue gas entering the gas turbines and of the flue gas leaving the HRSG and proceeding through the CO_2 recovery unit. The composition of the mixed stream of air and recycle flue gas is shown as stream number 40. The stream numbers correspond to the numbers in the scheme at the end of this section. The composition is in molar percentage.

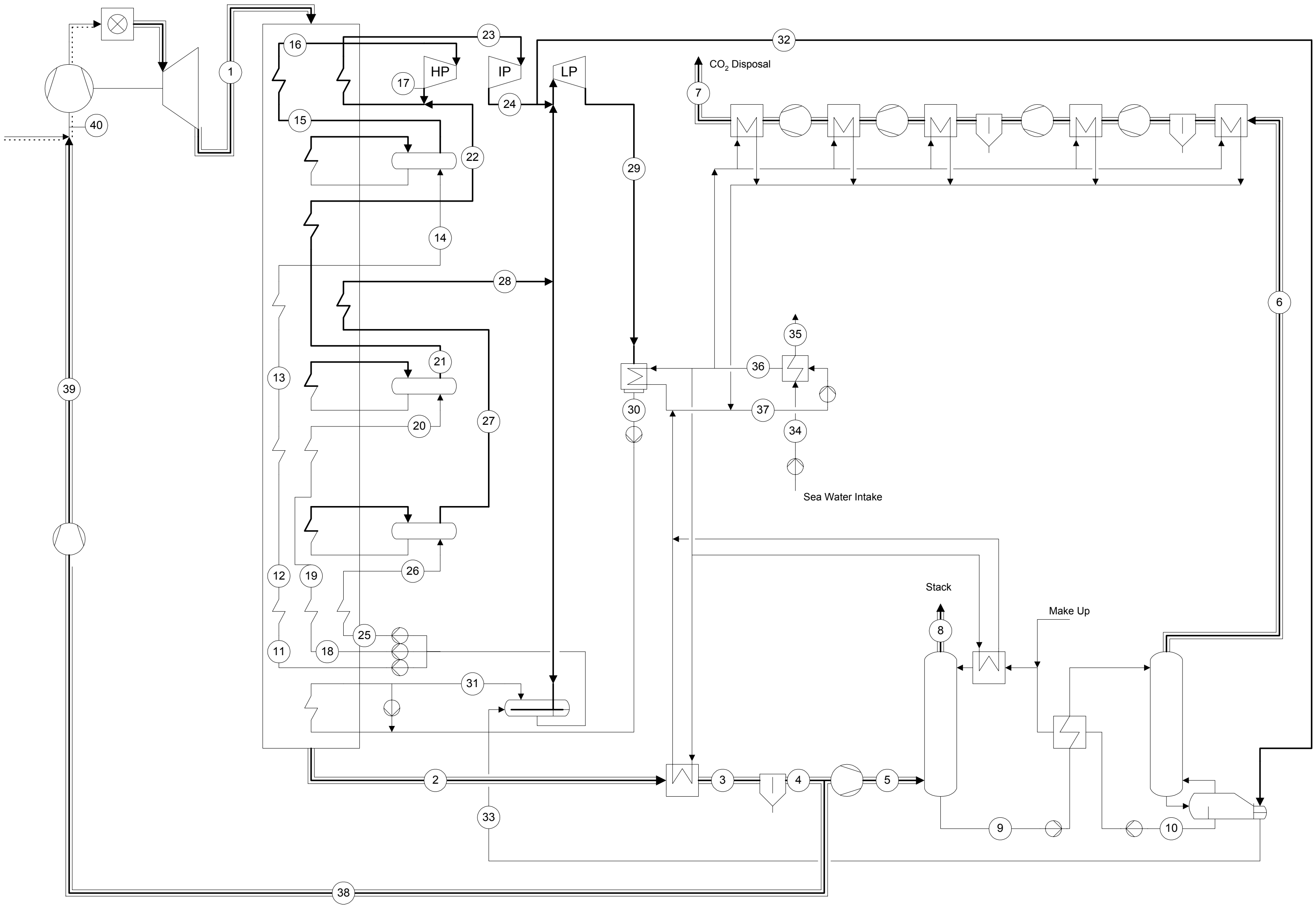
Component	*Air*	*2*	*4*	*6*	*7*	*8*	*9*	*10*	*40*
Ar	0.92	0.91	0.97	0.00	0.00	1.02	0.00	0.00	0.95
O_2	20.77	4.66	4.97	0.00	0.02	5.24	0.00	0.00	13.06
N_2	77.40	76.29	81.36	0.07	0.12	85.85	0.00	0.00	79.33
H_2O	0.87	9.73	3.73	41.99	0.32	6.46	92.40	93.51	2.26
CO_2	0.03	8.41	8.97	57.93	99.54	1.42	2.71	1.50	4.39
MEA	-	-	-	0.00	-	-	4.88	4.99	-

Table A4.3: Air and Gas compositions in molar %

The fuel gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves. The composition in molar percentage is as follows:

Component	
Methane	83.9 %
Ethane	9.2 %
Propane	3.3 %
Butane +	1.4 %
Carbon-dioxide	1.8 %
Nitrogen	0.4 %
Sulphur (as H_2S)	4 mg/Nm^3
Lower Heating Value	46.899 MJ/kg

Table A4.4: Fuel gas composition in molar % and LHV



HP
IP
LP
CO2 Disposal
Sea Water Intake
Stack
Make Up
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
31
32
33
34
35
36
37
38
39
40

Figure A4.1

MASS & ENERGY BALANCE

CASE

$C1_{W/O}$

IEA

THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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1. INTRODUCTION

Case $C1_{w/o}$ represents power generation in a pulverised coal fired critical steam cycle. The current state of development can be represented by a double reheat and steam conditions of 310/74/19 bar and 593 °C.

The state of the art in the year 2000 will not differ too much from this. The latest developed coal fired power plant is taken in operation in October 1998. In the near future (2005 - 2010) it is expected that it will be possible to design and build a super critical boiler with a pressure of 400 bar and 700 °C.

2. BOILER DESIGN

The boiler is an ultra supercritical once-through Benson tower type boiler with a spiral wound evaporator and a double reheat. The double reheat cycle is necessary to achieve high efficiency and keep the steam humidity low at the inlet of the LP turbines.

The boiler produces and delivers steam to the steam turbine at the following conditions:

		pressure	temperature
VHP	Very High Pressure	310 bar	593 °C
HP	High Pressure	74 bar	593 °C
IP	Intermediate Pressure	19 bar	593 °C

Table A5.1: Steam conditions HRSG

Coal is transferred from the coal bunkers and milled and burned in a set of low NOx burners. The coal specification is based on an open-cut coal from Eastern Australia; the proximate and ultimate analysis of this type of coal are specified in the technical reference document, appendix A. A fraction of unburned carbon of 0.47 % is lost through the hot ashes. Approximately 0.2% of the heat input is lost due to radiation of the boiler.

A plate type air preheater is used in which the combustion air is preheated to 320 °C by means of cooling down the flue gases to 120 °C. A plate type air preheater has no air leakage to the flue gas stream as opposed to a rotary type air preheater. The combustion air enters the air preheater at a temperature of 35 °C.

The following components in the boiler have a substantial power consumption:

- Induced draught fans
- Forced draught fans
- Primary air fans
- Milling equipment

3. STEAM TURBINE

The Steam turbine is split up in the following sections:

- A VHP section which is supplied with steam from the VHP superheater, expanded steam is supplied back to the boiler
- A HP section which is supplied with steam from the HP superheater, expanded steam is supplied back to the boiler
- A MP section which is supplied with steam from the MP superheater, expanded steam is supplied to the LP section
- A LP section which is supplied with steam from the MP section, expanded steam is supplied to the condenser

The Steam turbine has the following characteristics:

Section	*Overall isentropic efficiency*	*Inlet pressure*	*Inlet temperature*	*Outlet pressure*	*Outlet temperature*
Very High pressure	88.5 %	285 bar	580 °C	78 bar	375 °C
High pressure	88.5 %	74 bar	580 °C	20 bar	389 °C
Intermediate pressure	91.0 %	19 bar	580 °C	4.6 bar	374 °C
Low pressure	89.0 %	5.5 bar	397 °C	0.04 bar	29 °C

Table A5.2: Steam turbine characteristics

Steam is extracted from the MP section exhaust and 4 points of the LP section to preheat the condensate water. The deaerator is supplied with steam extracted from the MP section. Steam extracted from the VHP exhaust and the HP section further heats up the boiler feedwater.

4. CONDENSATE & FEED WATER SECTION

The condenser pressure is 0.04 bar. This is the saturation pressure at 29°C. This temperature is based on the sea water temperature of 12°C, the maximum allowed temperature rise of 7°C and a approach temperature of 3°C of the closed cooling water system. The sea water temperature and rise are specified in the technical reference document.

The condensate is preheated to a temperature of 155 °C in five steps by means of five condensate preheaters. The preheaters are supplied with steam extracted from the LP steam turbine section and the exhaust of the IP steam turbine.

The design of the condensate heating/deaerator system has been based on a maximum deaerating efficiency in combination with a maximum thermal efficiency.
Therefore the deaerator system will operate for the coal fired power plant at a pressure of 8 bar; 170 °C with a condensate feedwater temperature of 155 °C. For deaeration and heating of the condensate steam extracted from the MP steam turbine section will be used.

The boiler feedwater produced by the deaerator is brought to a pressure of 294 bar by means of a high efficiency boiler feedwater pump. Three boiler feedwater preheaters increase the temperature of the feedwater to 295 °C. The preheaters are supplied with steam extracted from the HP steam turbine section and from the exhaust of the VHP steam turbine section.

An economiser finally heats up the boiler feedwater to a temperature of 320 °C before it enters the spiral wound evaporator of the boiler.

5. FLUE GAS CLEANING

The flue gas cleaning of the power plant comprises three separate operations. Seen upstream of the flue gas these are:

- NOx removal (high dust Selective Catalytic Reduction, SCR)
- Dust removal by electrostatic precipitator (ESP)
- SO_2 removal (wet scrubbing)

The SCR DeNox reactor is integrated between the boiler and the air preheater. Based on a DeNox efficiency of over 80%, the NOx content in the reactor can be as low as 40 mg/MJ.

The plant consists of the following main components: an injection system for NH_3 placed directly after the boiler flue gas outlet.; an SCR DeNOx reactor with catalyst and sootblowers; and an NH3 supply plant.

The ESP is installed right after the air preheater. The flue gas passes to the ESP through a ducting connected to the inlet box arranged with a number of screens for equal gas distribution. The removed dust is stored in a flyash silo for transportation by truck to a buyer such as a cement factory.

For high level flue gas desulphurisation a single loop in situ oxidation process can be used. The flue gas is cleaned through an absorber system with ability of using either chalk or limestone as an absorbing agent. Gypsum that is produced can be the delivered to a series of buyers.

6. ENERGY BALANCE

The resulting energy balance becomes:

Energy balance		
Fuel Consumption LHV	1098.18 MW	
Steam Turbine	533.75 MW	
ST Shaft power		*541.71 MW*
ST Generator losses		*-7.96 MW*
ST Generator output		*533.75 MW*
Balance of Plant losses	-33.10 MW	
Boiler feedwater pumps		*-15.66 MW*
Cooling water pumps		*-6.60 MW*
Combustion air fans		*-2.18 MW*
Draught fans		*-4.0 MW*
Primary air fans		*-1.33 MW*
Electrostatic filter		*-0.36 MW*
Coal Pulveriser		*-2.86 MW*
Coal feeders		*-0.11 MW*
BOP losses		*-33.10 MW*
Total Plant net power	500.65 MW	
Net efficiency	45.59 %	

Table A5.3: Results energy balance

7. STREAM REPORT

Using the data specified in the technical reference document the following results were calculated using GateCycle.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	29.1	40.3	68.6	93.4	120.9	147.3	176.4	231.1	290.2	295.0
p (bar)	13.0	12.0	11.0	10.0	9.0	8.0	294.0	292.0	290.0	288.0
m (kg/s)	229.4	229.4	240.6	262.2	262.2	273.6	363.6	363.6	363.6	363.6
h (kJ/kg)	122.5	169.4	287.4	391.5	507.4	620.3	762.5	1002.0	1278.3	1302.5
quality	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	580.0	374.6	580.0	388.6	580.0	373.9	29.0	12.0	19.0	22.0
p (bar)	285.0	78.0	74.0	20.0	19.0	4.6	0.0	2.0	1.0	2.0
m (kg/s)	363.6	314.7	314.7	282.3	282.3	262.2	224.8	17959	17959	17769
h (kJ/kg)	3393.8	3069.0	3598.6	3222.1	3645.7	3217.7	2434.7	50.2	79.3	92.0
quality	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.00	0.00	0.00

Stream	*21*	*Combustion air*	*Flue gas*
T (C)	15.0	35.0	120.0
p (bar)	2.0	1.0	1.0
m (kg/s)	17769	451.6	488.8
h (kJ/kg)	62.7	19.8	109.8
quality	0.00	-	-

Table A5.4: Stream report results for a supercritical steam cycle

8. GAS COMPONENTS

The following Table shows the composition of combustion air and the flue gas of the considered supercritical steam cycle. The composition is given in mole fractions.

Component	*Combustion Air*	*Flue Gas*
Ar	0.90 %	0.86 %
O_2	20.25 %	3.23 %
N_2	75.48 %	71.97 %
H_2O	3.33 %	10.09 %
SO_2	-	4800 mg/Nm3
CO_2	0.03 %	13.79 %

Table A5.5: Exhaust gas composition in molar percentage

9. COAL

The coal specification is based on an open-cut coal from Eastern Australia

Proximate analysis:	*weight %*
coal (dry, ash free)	78.3
ash	12.2
moisture	9.5

Ultimate analysis: *Dry, ash free*	*weight %*
Carbon	82.5
Hydrogen	5.6
Oxygen	9.0
Nitrogen	1.8
Sulphur	1.1
Chlorine	0.03

Ash analysis:	*weight %*
SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7

HHV	27.06 MJ/kg
LHV	25.87 MJ/kg
Hardgrove index	45
Ash fusion point (reducing atmosphere)	1350 °C

Table A5.6: Coal characteristics

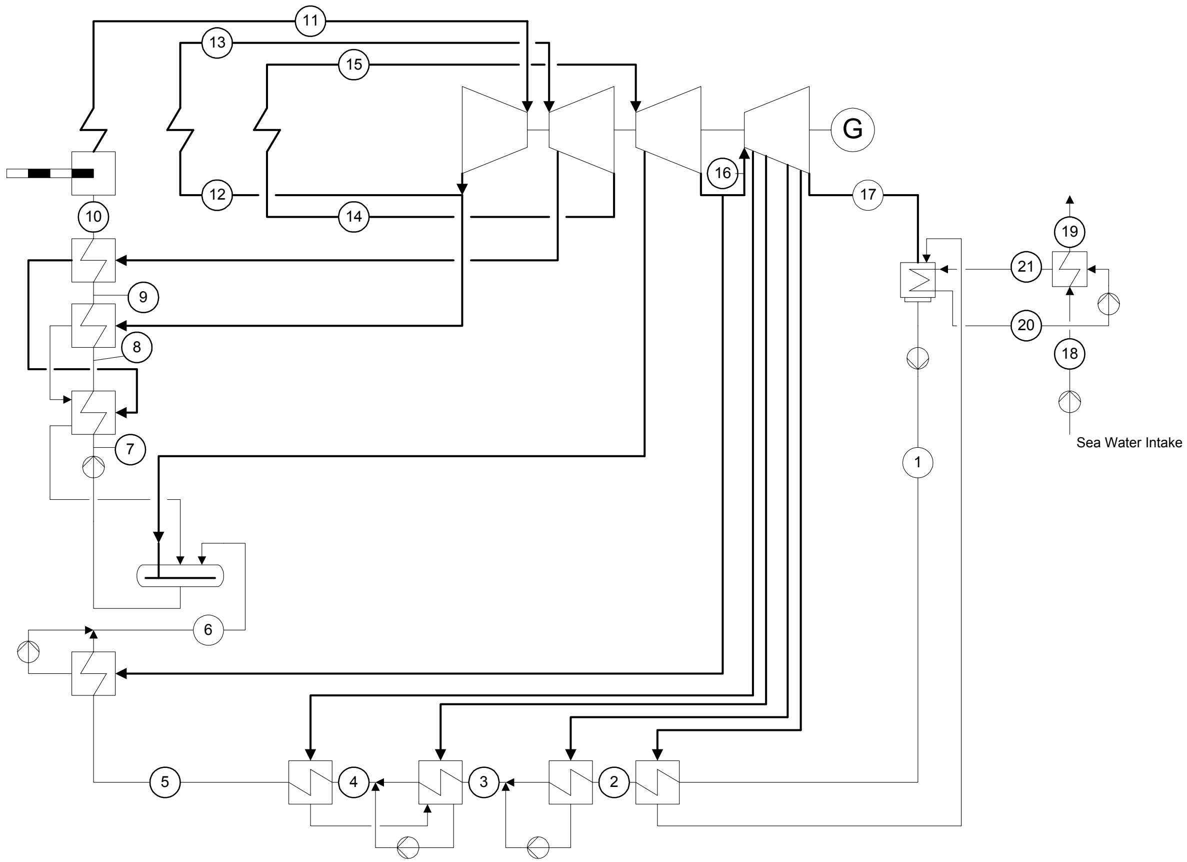

Figure A5.1

MASS & ENERGY BALANCE

CASE

$C1_W$

IEA

THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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Made by : HOY
Checked by : KOMI
Project appr'd by : WASE

1. INTRODUCTION

Case $C1_w$ represents power generation in a pulverised coal fired critical steam cycle with CO_2 recovery from the flue gasses. The design of the super critical steam cycle is in accordance with case C1, the coal fired power plant without CO_2 recycle.

2. CO_2 RECOVERY UNIT

The following components are added for the CO_2 recovery unit:

- **flue gas cooling** to cool down the flue gas to a temperature of 32 °C
- **flue gas fan** to force the flue gas through the absorber column, the pressure increase of this fan is 40 mbar
- **CO_2 absorber unit** to absorb the CO_2 from the flue gases
- **CO_2 compressor** to compress the CO_2 to the injection pressure of 110 bar
- **steam extraction** for the regenerator of the CO_2 absorber

For the overall design of the CO_2 recovery unit reference is made to case G1w, the combined cycle with CO_2 recovery.

Steam Extraction Points

The stripper requires a heat duty to remove the CO_2 from the MEA solution. A reboiler condenses LP steam extracted from the steam turbine to supply the heat duty to the stripper. LP steam is extracted from the IP steam turbine exit at 4.6 bar and 374°C and condensed in the reboiler to 3.6 bar and 125 °C. The steam is extracted from the main steam flow entering the LP turbine. The condensate returning from the reboiler is brought to pressure by a pump and added to the condensate flow, just before the last condensate preheater.

3. ENERGY BALANCE

The resulting energy balance becomes:

Energy balance		
Fuel Consumption LHV	1098.18 MW	
Steam Turbine	440.51 MW	
ST Shaft power		*447.08 MW*
ST Generator losses		*-6.57 MW*
ST Generator output		*440.51 MW*
Balance of Plant losses	-31.00 MW	`
Boiler feedwater pumps		*-15.59 MW*
Cooling water pumps		*-4.57 MW*
Combustion air fans		*-2.18 MW*
Draught fans		*-4.00 MW*
Primary air fans		*-1.33 MW*
Electrostatic filter		*-0.36 MW*
Coal Pulveriser		*-2.86 MW*
Coal feeders		*-0.11 MW*
BOP losses		*-31.00 MW*
CO_2 recovery unit	-47.24 MW	
flue gas fan		*-2.06 MW*
Absorber recycle pump		*-5.99 MW*
Compressor		*-34.32 MW*
Add. Cooling water pumps		*-4.87 MW*
CO_2 recovery penalty		*-47.24 MW*
Total Plant net power	362.27 MW	
Net efficiency	32.99 %	

Table A6.1: Results energy balance

4. STREAM REPORT

Using the data specified in the technical reference document the following results were calculated using GateCycle.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	29.1	40.3	68.6	93.4	123.1	147.3	176.4	231.1	290.2	295.0
p (bar)	13.00	12.00	11.00	10.00	9.00	8.00	294.00	292.00	290.00	288.00
m (kg/s)	114.7	114.7	120.4	131.3	263.1	273.6	363.6	363.6	363.6	363.6
h (kJ/kg)	122.5	169.4	287.4	391.5	516.7	620.3	762.5	1002.0	1278.3	1302.5
quality	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	1.00	1.00

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	580.0	374.6	580.0	388.6	580.0	373.9	29.0	12.0	19.0	22.0
p (bar)	285.00	78.00	74.00	20.00	19.00	4.60	0.04	2.00	1.00	1.50
m (kg/s)	363.6	314.7	314.7	282.3	282.3	131.3	112.4	19473.8	19473.8	19252.2
h (kJ/kg)	3393.8	3069.0	3598.6	3222.1	3645.7	3217.7	2434.7	50.2	79.4	92.0
quality	1.00	1.00	1.00	1.00	1.00	1.00	0.95	0.00	0.00	0.00

Stream	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
T (C)	15.0	120.0	32.0	32.0	36.3	87.7	35.0	45.2	43.5	111.03
p (bar)	2.00	1.01	1.01	1.01	1.05	1.50	110	1.01	1.05	1.6
m (kg/s)	19252.2	488.8	488.8	471.9	471.9	111.2	85.6	395.9	3167.9	3056.7
h (kJ/kg)	62.7	109.8	17.1	16.6	21.0	-	-	-	-	-
quality	0.00	-	-	-	-	-	-	-	-	-

Stream	*31*	*32*	*Combustion Air*
T (C)	373.9	125	35.0
p (bar)	4.6	3.6	1.01
m (kg/s)	131.8	131.8	451.6
h (kJ/kg)	3217.6	524.6	19.8
quality	1.0	0.0	-

Table A6.2: Stream report results for a supercritical steam cycle

5. GAS COMPONENTS

The following table shows the composition of gas and liquid flows in the power plant and absorber unit. The composition is given in mole fractions.

Component	*Combustion Air*	*22*	*24*	*26*	*27*	*28*	*29*	*30*
Ar	0.90 %	0.86 %	0.91 %	0.00 %	0.00 %	1.00 %	-	-
O_2	20.25 %	3.23 %	3.42 %	0.01 %	0.02 %	3.76 %	-	-
N_2	75.48 %	71.97 %	76.29 %	0.06 %	0.10 %	83.84 %	-	-
H_2O	3.33 %	10.09 %	4.70 %	42.33 %	0.32 %	8.91 %	92.38 %	93.51 %
SO_2	-	-	-	-	-	-	-	-
CO_2	0.03 %	13.79 %	14.61 %	57.58 %	99.52 %	2.41 %	2.74 %	1.50 %
MEA	-	-	-	-	-	-	4.88 %	4.99 %

Table A6.3: Exhaust gas composition in molar percentage

6. COAL

The coal specification is based on an open-cut coal from Eastern Australia

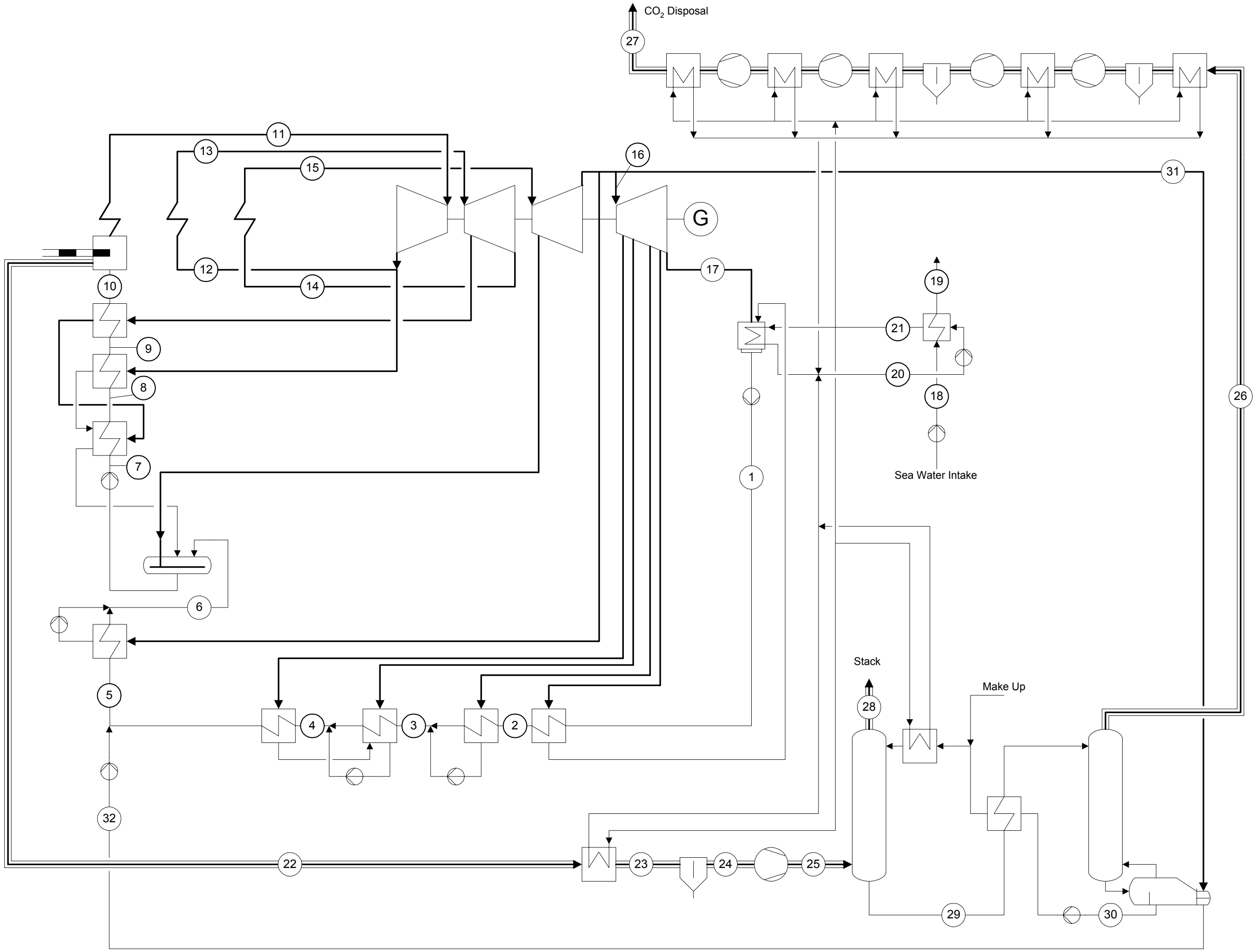
Proximate analysis:	*weight %*
coal (dry, ash free)	78.3
ash	12.2
moisture	9.5

Ultimate analysis: Dry, ash free	*weight %*
Carbon	82.5
Hydrogen	5.6
Oxygen	9.0
Nitrogen	1.8
Sulphur	1.1
Chlorine	0.03

Ash analysis:	*weight %*
SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7

HHV	27.06 MJ/kg
LHV	25.87 MJ/kg
Hardgrove index	45
Ash fusion point (reducing atmosphere)	1350 °C

Table A6.4: Coal characteristics


CO2 Disposal
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Make Up
Sea Water Intake
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Figure A6.1

MASS & ENERGY BALANCE
CASE
$C2_{W/O}$

IEA
THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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Issue : 2, final
Made by : HOY
Checked by : KOMI
Project appr'd by : WASE

1. INTRODUCTION

Case $C2_{w/o}$ represents power generation in an Integrated coal Gasification Combined Cycle (IGCC). The power plant consists of a gasifier, a gas treatment section, a gas turbine and a Heat Recovery Steam Generator (HRSG) with a steam turbine. The current state of the art suggests a cold gas treatment, further development steps towards hot gas treatment are not to be expected in the near future.

To obtain mass and energy balances a model has been set up in GateCycle 5.2. The model simulates the gasifier by minimising the free Gibbs energy of the flows entering the Gasifier. The approach temperature at which GateCycle calculates this chemical equilibrium is 1563 °C.

2. GASIFIER

The gasifier is based on the Shell coal Gasification technology, operating at 27 bar and 1613 °C. The Shell coal gasifier converts coal to a syngas, the main characteristic of the Shell process is that the syngas is quenched at the exit of the gasifier to a temperature of 900 °C. Recycled and cooled down syngas is used to quench the hot syngas in the gasifier.

Coal dried to 3% (mass) moisture enters the gasifier through a pneumatic feeder, a small amount of inert nitrogen to seal of the lockhopper enters through this feeder. The inert Nitrogen is produced by the air separation unit. To enable gasification of the coal oxygen from the air separation unit is provided to the gasifier after it has been compressed to 32 bar.

To prevent too high wall temperatures in the gasifier, water cooled walls have been provided. Water is evaporated at 44 bar in the wall section and routed to a superheater in the gascooling section prior to feeding the steam to the steam turbine. Part of this steam is supplied to the gasifier to enable the gasification process.

The following proportions of coal, oxygen, steam, and nitrogen enter the gasifier:

Per kg of dry coal (3% moisture)	
Oxygen	0.848 kg
Steam	0.066 kg
Nitrogen	0.066 kg

Table A7.1: Gasifier feed per kg of dry coal

The gas produced by the gasifier at 1613 °C is directly quenched and cooled down to about 230 °C prior to the first cleaning step (i.e. dust extraction). The cooling of the syngas is achieved by:

- quenching to 900 °C with cooled syngas, which is derived from he syngas stream downstream of the gascooler.
- cooling the syngas further to 230 °C by means of a gas cooler. The heat extracted from the syngas is used for generating and superheating IP and HP steam, which is supplied to the steam turbine for generating power.

A compressor brings the recycle gas, used to quench the syngas, to the desired pressure.

The moisture level of the wet coal is reduced to 3% moisture by means of a coal dryer. Approximately 0.23 MW of fuel is necessary per kg wet coal. The fuel gas is extracted from the main fuel gas flow after it leaves the gas cleaning section. Drying of the coal is necessary to enable a proper feed of the coal into the gasifier.

3. GAS TREATMENT

The gas treatment of the syngas produced in the gasifier is required to make the gas suitable for combustion in the gas turbine. The Gas turbine requirements are, amongst others, no particulates and a low sulphur level, both in terms of Hydrogen Sulphide and Carbonyls Sulphide.

To enhance the cycle efficiency and reduce NOx emissions of the Gas Turbine the syngas is saturated with water and the remainder of the Nitrogen, that is produced by the air separation unit, is added to the syngas stream.

This implies the following steps in the gas treatment section:

- Removal of particulates in a Scrubber
- Hydrolysis of the Carbonyl Sulphide
- Desulphurisation
- Saturating the syngas with water
- Diluting the syngas with Nitrogen

The preceding steps and especially the Desulphuriation are performed at low temperature. Within the current state of the art there is little experience with equipment that can clean the syngas at a high temperature.

After the gas is quenched to 908°C, the gas is cooled to 232 °C in a gas cooling section. This section contains a radiation screen which evaporates water of 130 bar, two parallel super heaters, an evaporator and an economiser. The water used in the gas cooler is derived from the HRSG that is connected to the Gas Turbine. The full details are given in the mass balances in the stream report.

Gas of 232°C is passed through a wet scrubbing section which removes the particulates. A flash tank removes the liquid droplets of water present in the flow downstream of the wet scrubber. The scrubber cools down the gas to 123°C and increases the mass flow by adding water to the syngas flow.

A COS Hydrolysis unit reduces the amount of Carbonyl Sulphide (COS) present in the syngas to a level below 10 ppm. This process takes place at 180°C. High pressure water (135 bar, 200 °C) derived from the HRSG economiser heats up the gas to this level.

The desulphurisation process takes place at a low temperature of 38 °C of the syngas. The gas is cooled to this temperature by:

- Water used for saturating the syngas in the next step
- Cooling water

After cooling the condensate that is formed in the gas is separated from the gas by a knock-out vessel. Steam of 11.5 bar supplies the heat duty for the desulphurisation process. This steam is derived from the HRSG.

After desulphurisation the clean gas is saturated with water to enhance the gas turbine performance and reduce the NOx emissions. Nitrogen, originating from the air separation unit, of 300 °C is added to dilute the combustion gas. The syngas is heated to 300 °C by cooling down nearly saturated HP water derived from the HRSG.

4. GAS TURBINE

The Gas turbine is a modified GE frame 9. The following modifications are required for this gas turbine:

- The compressor to enable the export of compressed air to the oxygen plant
- The fuel nozzle to allow for a higher mass flow of the low LHV syngas fuel.

The combustion of a low LHV syngas fuel and the extraction of air from the compressor is modelled in such a way that the fluegas flow and temperature entering the turbine expander are similar compared to a natural gas fired gas turbine.

5. HRSG

The HRSG is a non fired double pressure natural circulation boiler with single reheat. As the installation is considered to be a base load operating power plant the design is optimised with respect to the overall efficiency of the system. The higher overall efficiency will consequently result in reduction of the CO_2 emission. Therefore the following design conditions have been selected:

1. The HRSG supplies steam to the steam turbine at the following pressures and temperatures:

		Pressure	*Temperature*
HP:	High pressure	120 bar	560 °C
IP:	Intermediate pressure	29 bar	560 °C
LP:	Low pressure	3.2 bar	200 °C

Table A7.2: Steam properties HRSG

In order to achieve this the heat exchangers in the HRSG are set up according to the following table:

High pressure superheater	Steam temperature	560 °C
Medium pressure superheater / reheater	Steam temperature	560 °C
Low pressure superheater	Steam temperature	200 °C
High pressure economiser	Degrees of subcooling	5 °C
Water preheater	Exit temperature	120 °C
Evaporator (low and high pressure)	Pinch delta temperature	8 °C

Table A7.3: HRSG set-up

2. The HRSG supplies HP economiser water at two temperature levels to the following equipment:

HP economiser water	*equipment*
at 200 °C	COS Hydrolysis
	Gasifier water walls (let down to 44 bar)
	Gas cooler economiser
at 328 °C	Fuel gas heater
	Gas cooler evaporator

Table A7.4: Water consumers

3. Economiser water that has been used for heating is increased in pressure and integrated in the HRSG.

4. HP steam that has been generated and superheated by the Gas cooler is mixed with HP steam from the HRSG and further superheated before it is supplied to the HP steam turbine section.

5. IP steam that has been generated in the water cooled walls of the gasifier and superheated in the gas cooler is mixed with steam exiting the HP steam turbine section and superheated in the HRSG before it enters the IP steam turbine section.

6. In the design no additional facilities have been shown which are required for operation of the plant over the complete operating range such as de-superheating equipment.

The design of the condensate heating/deaerator system has been based on a maximum deaerating efficiency in combination with a maximum thermal efficiency. The deaerator water is directly supplied to the LP evaporator. The deaerator system operates at a pressure of 3.0 bar; 134 °C with a condensate feedwater temperature of 120 °C. For deaeration and heating of the condensate LP steam will be used. Condensate returning from the desulphurisation unit is also fed into the deaerator.

The condensate out of the condensor will be heated from 29° C to 120 °C by means of a closed water loop which is using the flue gas heat from the stack to preheat the condensate. Direct heating the condensate with flue gas is not possible because the condensate entry temperature is below the dew point of the flue gas. For modelling purposes this is achieved not by a closed water loop but by mixing 120 °C water exiting the preheat section with 29 °C water entering the preheat section in order to increase this temperature from 29 °C to a safe level of 60 °C.

List of remaining starting points:

- For calculation of the auxiliary power consumption all the pumps used have an overall efficiency of 75%.
- The steam turbine generator efficiency is 98%
- The cooling water consumption used by auxiliary systems other than the condensor and gas coolers is set at 1000 m^3/hr
- Blow down is set at 0%
- Minor steam losses, such as the ejector steam and gland steam are neglected.

6. STEAM TURBINE

The steam turbine is a condensing steam turbine consisting of the following sections:

- a HP section which is supplied with steam from the HP superheater
- an IP section which is supplied with a mixture of IP steam from gas cooler superheater and steam from the HP turbine which is reheated in the reheat section. Steam is extracted from the IP steam section to supply heat to the desulphurisation unit.
- a condensing LP section which is supplied with a mixture of steam from the LP superheater and steam from the IP turbine section

The steam turbine has the following characteristics:

Section	*Overall isentropic efficiency*	*Inlet pressure*	*Inlet temperature*	*Outlet pressure*	*Outlet temperature*
High pressure	86.5 %	120 bar	560 °C	30.5 bar	363 °C
Intermediate pressure	88.0 %	29 bar	560 °C	3.2 bar	272 °C
Low pressure	89.5 %	3.2 bar	271 °C	0.04 bar	29 °C

Table A7.5: Steam turbine characteristics

The condenser pressure is 0.04 bar. This is the saturation pressure at 29°C. This temperature is based on the sea water temperature of 12°C, the maximum allowed temperature rise of 7°C and a approach temperature of 3°C of the closed cooling water system. The closed cooling water system also supplies cooling water to other equipment in the installation. The sea water temperature and rise are specified in the technical reference document.

7. AIR SEPARATION UNIT

The cryogenic air-separation process produces 95 % pure oxygen, necessary for the gasification process, from air extracted from the gas turbine compressor. The air separation unit (ASU) liquefies the air and separates it into Nitrogen an Oxygen. The product gasses are compressed to their desired pressure levels by intercooled multistage compressors.

The gas turbine compressor delivers air at a pressure of 15 bar, however for the ASU a pressure of only 11 bar is necessary. To simplify the integration with the gas turbine, the air is not extracted at a lower pressure from a point half way the compressor, but it is expanded to the desired pressure by means of an expander-turbine. Power generated by the expander contributes to the power requirement of the ASU.

The nitrogen produced by the ASU is partly used to feed the coal into the gasifier. The remainder part is mixed with the fuel gas in order to lower the flame temperature and to increase the power output of the gas turbine and the overall plant efficiency.

8. STREAM REPORT

Using the data specified in the technical reference document the following results were calculated using GateCycle.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	908	778	232	232	123	162	180	180	140	99
p (bar)	27.34	27.34	26.50	26.50	25.83	25.53	23.83	23.83	23.53	23.33
m (kg/s)	125.4	125.4	125.4	67.6	61.5	61.5	61.5	61.5	61.5	61.5
h (kJ/kg)	1399.1	1188.4	351.9	351.9	342.4	401.0	427.4	427.4	368.9	306.9
quality										

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	40	40	38	115	300	300	1330	619	81	134
p (bar)	22.80	22.60	22.10	21.61	21.61	21.61	14.91	1.04	1.01	4.70
m (kg/s)	59.1	57.1	55.3	59.2	59.2	136.5	-	641.5	641.5	8.5
h (kJ/kg)	127.0	41.9	38.4	315.7	591.3	425.1	1633.0	740.3	149.9	561.7
quality										0.00

Stream	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
T (C)	141	200	200	272	270	136	200	200	328	330
p (bar)	3.70	3.20	3.20	3.20	3.20	137.50	135.50	135.50	133.50	128.50
m (kg/s)	8.5	8.5	2.6	119.3	121.9	130.6	147.9	109.0	50.2	50.2
h (kJ/kg)	2734.5	2864.1	2864.1	3011.1	3008.0	580.9	857.0	857.0	1507.7	2665.3
quality	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	1.00

Stream	*31*	*32*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*40*
T (C)	345	560	328	328	328	331	331	363	328	200
p (bar)	125.00	120.00	133.50	133.50	132.00	130.00	130.00	125.00	133.50	135.50
m (kg/s)	124.8	124.8	58.9	34.0	51.7	51.7	74.6	74.6	24.9	38.9
h (kJ/kg)	2799.4	3505.8	1507.7	1507.7	1509.8	2661.8	2661.8	2889.6	1507.7	857.0
quality	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00	0.00	0.00

Table A7.6: Stream report

Mass & Energy Balance $C2_{w/o}$

Stream	*41*	*42*	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*
T (C)	200	328	200	167	328	331	200	201	256	350
p (bar)	135.50	132.00	135.50	126.50	132.00	130.00	135.50	44.00	44.00	41.00
m (kg/s)	40.7	40.7	11.4	11.4	22.9	22.9	6.0	5.8	5.8	5.8
h (kJ/kg)	856.0	1511.5	856.0	712.9	1509.8	2661.8	856.0	856.0	2798.6	3089.6
quality	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	1.00	1.00

Stream	*51*	*52*	*53*	*54*	*55*	*56*	*57*	*58*	*59*	*60*
T (C)	350	363	560	350	363	139	97	38	94	105
p (bar)	41.00	30.50	29.00	41.00	30.50	32.00	21.61	32.53	33.00	32.50
m (kg/s)	3.7	128.5	128.5	2.1	124.8	83.0	79.1	3.9	83.0	83.0
h (kJ/kg)	3089.6	3143.0	3592.1	3089.6	3144.6	586.4	405.5	160.3	395.5	441.4
quality	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00

Stream	*61*	*62*	*63*	*64*	*65*	*66*	*67*	*68*	*69*	*70*
T (C)	29	29	120	9	399	347	224	120	300	120
p (bar)	0.04	0.04	5.00	1.01	15.45	11.00	11.00	21.90	21.90	32.24
m (kg/s)	121.9	121.9	178.6	628.0	123.0	113.2	113.2	77.3	77.3	26.7
h (kJ/kg)	2357.8	120.7	503.4	4.1	407.1	351.9	222.6	108.4	297.8	95.2
quality	0.92	0.00	0.00							

Stream	*71*
T (C)	180
p (bar)	31.24
m (kg/s)	26.7
h (kJ/kg)	151.1
quality	

Table A7.6: Stream report (cont.)

9. SYNGAS AND FLUE GAS COMPONENTS

The following Table shows the syngas and flue gas composition of the considered IGCC.

Stream #	1	5	8	12	13
Ar	1.0	1.0	1.0	1.0	1.0
H_2	29.5	27.6	27.6	30.0	30.1
O_2	-	-	-	-	-
N_2	3.6	3.4	3.4	3.7	3.7
H_2O	1.8	8.4	8.4	0.3	0.3
H_2S	0.3	0.3	0.3	0.3	0.0
SO_2	-	-	-	-	-
CO	62.7	58.6	58.6	63.7	63.9
CO_2	1.0	0.9	0.9	1.0	1.0
COS	0.0	0.0	0.0	0.0	0.0
CH_x	0.0	0.0	0.0	0.0	0.0

Stream #	16	19	64	68	70
Ar	0.6	0.9	0.9	0.2	3.5
H_2	14.3	0.0	0.0	-	-
O_2	0.3	10.0	20.81	0.7	95.1
N_2	49.8	74.6	77.55	99.0	1.4
H_2O	4.0	5.7	6.79	0.0	0.0
H_2S	0.0	0.0	0.0	-	-
SO_2	-	-	-	-	-
CO	30.3	0.0	0.0	-	-
CO_2	0.5	8.7	0.0	0.0	0.0
COS	0.0	0.0	0.0	-	-
CH_x	0.0	0.0	0.0	-	-

Table A7.7: Gas compositions in molar percentages.

10. ENERGY BALANCE

Energy balance		
Fuel Consumption LHV	880.00 MW	
Gas Turbine	250.71 MW	
GT Shaft power		*255.31 MW*
GT remaining losses		*-1.54 MW*
GT Generator losses		*-3.13 MW*
Net GT power		*250.71 MW*
Steam turbine	192.32 MW	
ST Shaft power		*196.24 MW*
ST Generator losses		*-3.92 MW*
ST Generator output		*192.32 MW*
Balance of plant losses	-7.53 MW	
Boiler feedwater pumps		*-2.81 MW*
Cooling water pumps		*-2.76 MW*
Remaining losses		*-1.96 MW*
BOP losses		*-7.53 MW*
Air Separation Unit	-20.26 MW	
Air expander power		*9.46 MW*
Oxygen compressor		*-8.09 MW*
Nitrogen compressor		*-21.63 MW*
ASU losses		*-20.26 MW*
Gasifier losses	-7.47 MW	
Recycle compressor		*-1.46 MW*
Saturator pumps		*-0.13 MW*
Coal treatment		*-1.53 MW*
Aux power		*-4.35 MW*
Gasifier losses		*-7.47 MW*
Total plant net power	407.76 MW	
Net Efficiency	46.34%	

Table A7.8: Results energy balance

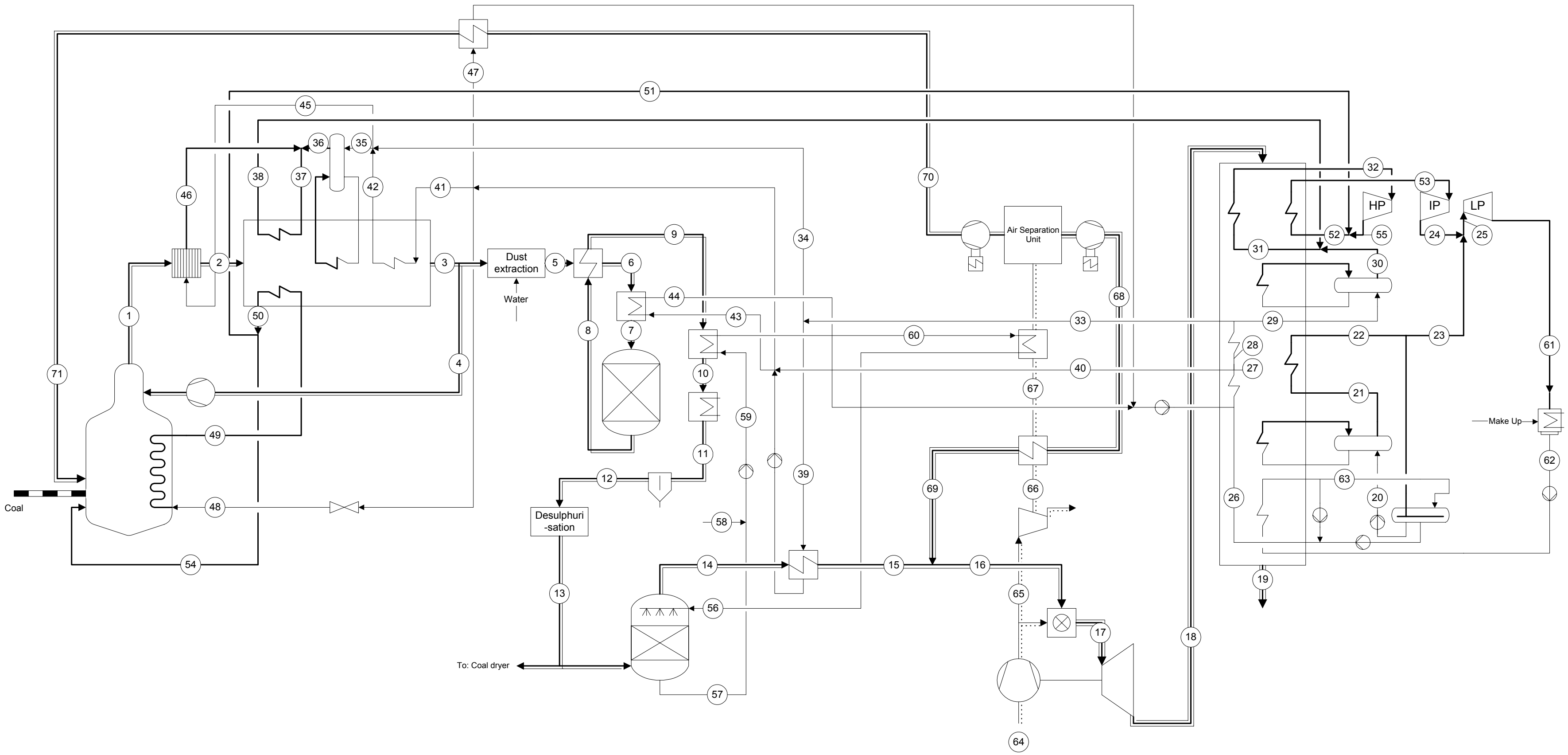
Coal
Dust extraction
Water
Desulphuri -sation
To: Coal dryer
Air Separation Unit
HP
IP
LP
Make Up

Figure A7.1

MASS & ENERGY BALANCE
CASE
$C2_W$

IEA
THE ASSESSMENT OF LEADING TECHNOLOGY
OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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Project appr'd by	:	WASE

1. INTRODUCTION

Case $C2_w$ represents an integrated gasification combined cycle (IGCC) with pre-combustion CO_2 removal by means of a double shift reaction and a physical solvent based absorber. The shift reactor transforms the CO/H_2 syngas produced by the coal gasifier into a mixture of H_2 and CO_2. The absorber combination removes the CO_2 from the fuel gas stream and a hydrogen rich fuel gas can be combusted in the gas turbine. A compressor brings the CO_2 to injection pressure.

The design of the IGCC is done as much as possible with the design specifications mentioned in case $C2_{wo}$. Due to the integration of the double shift reactor and the absorber some modifications are inevitable. Only the modifications will be mentioned throughout this mass and energy balance, for the design of the IGCC reference is made to the mass and energy balance of case $C2_{wo.}$

2. SHIFT REACTOR AND CO_2 REMOVAL

The syngas produced by the gasifier passes the gas cooler, dust extraction unit, COS hydrolysis unit and desulphurisation unit before entering the double shift reactor.
The double shift reactor shifts the CO/H_2 syngas produced by the gasifier in two separate steps into a mixture of H_2 and CO_2. To enable the shift reaction, IP steam must be added to the syngas stream entering the first shift reactor and the steam / gas mixture entering has to be heated up to 350 °C. As the processes in the two shift reactors are exothermic, heat can be recovered. The heat recovering system is integrated into the cycle according to the following table.

Heat recovered from the:	*Cycle integration:*	*MWth (approx.)*
First Shift reactor	HP evaporator	12 MWth
	heating of feed for first shift reactor	7 MWth
	heating of syngas	12 MWth
	LP evaporator	24 MWth
	cooling water loss	10 MWth
Second shift reactor	heating of syngas	11 MWth
	cooling water loss	15 MWth

Table A8.1: Heat recovery shift reactors

The H_2 / CO_2 mixture then enters a physical solvent process where a selexol solution physically removes the CO_2 from the mixture. The CO_2 is recovered from the solution by reducing the pressure in two steps. The first step releases CO_2 at 6.3 bar, the second at 1.5 bar. The CO_2 than enters the CO_2 compressor at these two pressure levels to reduce the amount of work necessary to compress the CO_2 to 110 bar. For the design of the compressor station reference is made to case $G1_w$.

In the selexol recovery process, energy is required for pumping the selexol. A hydraulic turbine recovers some of the energy by reducing the pressure of the selexol.

The H_2 rich fuel gas proceeds through the saturator where water is added to enhance the performance of the gas turbine and reduce NO_x emissions. The remainder of the N_2 from the ASU is added to enhance the cycle performance, and the gas is combusted in the GE Frame 9 FA gas turbine.

3. GAS TURBINE

The Gas turbine is a modified GE frame 9. The following modifications are required for this gas turbine:

- The compressor to enable the export of compressed air to the oxygen plant
- The fuel nozzle to allow for a higher mass flow of the low LHV syngas fuel.
- The combustor should be able to combust a H_2 rich gas without excessive NOx emissions (limits are stated in the technical reference document)
- The expander turbine should allow the expansion of flue gas with a high H_2O content due to the combustion of the H_2 rich syngas.

The combustion of a low LHV syngas fuel and the extraction of air from the compressor is modelled in such a way that the fluegas flow and temperature entering the turbine expander are similar compared to a natural gas fired gas turbine.

The higher combustion value of the H_2 rich gas (compared to case $C2_{w/o}$) reduces the amount of air extracted from the gas turbine compressor: A higher combustion value reduces the fuel flow in the combustor therefore less air has to be extracted from the compressor to establish a flow through the turbine that is similar to the natural gas operation mode of the gas turbine.

4. HRSG

To enable the shift reaction, IP steam will be extracted from the HP steam turbine section exhaust flow. This steam is mixed in the syngas flow and additional make up flow is necessary to compensate for this loss.

The exothermic shift reactors supply extra heat duty to the steam cycle. The hot stream out of the first shift reactor provides heat to evaporate HP water (12 MWth) and LP water (24 MWth).

5. AIR SEPARATION UNIT

The design of the air separation unit does not differ from the ASU in case $C2_{w/o}$. The amount of air that is extracted from the gas turbine compressor is however not enough to fully supply the ASU with pressurised air. Therefore an additional air compressor will be installed to supply the remainder of pressurised air.

The amount of air that is extracted from the gas turbine compressor is lower than in case $C2_{w/o}$ due to the high heating value of the H_2 rich gas. This is explained in paragraph 3, covering the gas turbine.

6. STREAM REPORT

Using the data specified in the technical reference document the following results were calculated using GateCycle.

Stream	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
T (C)	903	778	222	222	123	162	180	180	140	97
p (bar)	27.34	27.34	26.50	26.50	25.83	25.53	23.83	23.83	23.53	23.33
m (kg/s)	142.79	142.79	142.79	76.93	69.96	69.96	69.96	69.96	69.96	69.96
h (kJ/kg)	1390.8	1188.4	336.9	336.9	340.7	399.3	425.7	425.7	367.2	302.6
quality										

Stream	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*
T (C)	40	40	38	155	278	350	422	329	100	177
p (bar)	22.80	22.60	22.10	22.00	21.80	21.60	21.50	21.10	20.50	20.30
m (kg/s)	67.11	65.00	65.00	65.00	65.00	98.10	98.10	98.10	98.10	98.10
h (kJ/kg)	121.3	41.9	38.4							
quality										

Stream	*21*	*22*	*23*	*24*	*25*	*26*	*27*	*28*	*29*	*30*
T (C)	37	34	111	300	1331	611	81	20	20	35
p (bar)	20.00	20.00	19.50	19.50	14.91	1.04	1.01	6.30	1.50	110.00
m (kg/s)	97.06	19.28	23.14	111.14	-	640.16	640.16	42.60	34.85	77.46
h (kJ/kg)		150.8	903.2	595.0	1860.8	897.2	287.8			
quality										

Stream	*31*	*32*	*33*	*34*	*35*	*36*	*37*	*38*	*39*	*40*
T (C)	9	399	9	340	217	120	300	120	180	134
p (bar)	1.01	15.45	1.01	11.00	11.00	21.90	21.90	32.24	31.24	4.70
m (kg/s)	628.03	99.00	29.93	128.93	128.93	88.00	88.00	30.37	30.37	15.23
h (kJ/kg)	4.1	407.1	4.1	344.4	215.2	108.4	297.8	95.2	151.1	561.7
quality										0.00

Table A8.2: Stream report

Stream	*41*	*42*	*43*	*44*	*45*	*46*	*47*	*48*	*49*	*50*
T (C)	141	200	200	272	264	136	200	200	328	330
p (bar)	3.70	3.20	3.20	3.20	3.20	137.50	135.50	135.50	133.50	128.50
m (kg/s)	15.23	15.23	12.49	102.40	114.90	148.36	168.35	121.57	47.89	47.89
h (kJ/kg)	2734.5	2864.1	2864.1	3011.1	2995.1	580.9	857.0	857.0	1507.7	2665.3
quality	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	1.00

Stream	*51*	*52*	*53*	*54*	*55*	*56*	*57*	*58*	*59*	*60*
T (C)	347	560	328	328	328	331	331	363	328	330
p (bar)	125.00	120.00	133.50	133.50	132.00	130.00	130.00	125.00	133.50	128.50
m (kg/s)	132.04	141.77	63.95	33.95	59.04	59.04	84.15	84.15	30.00	9.73
h (kJ/kg)	2808.2	3505.8	1507.7	1507.7	1510.0	2661.8	2661.8	2889.6	1507.7	2665.3
quality	1.00	1.00	0.00	0.00	0.00	1.00	1.00	1.00	0.00	1.00

Stream	*61*	*62*	*63*	*64*	*65*	*66*	*67*	*68*	*69*	*70*
T (C)	200	202	328	202	170	328	331	202	202	256
p (bar)	135.50	135.50	132.00	135.50	126.50	132.00	130.00	135.50	44.00	44.00
m (kg/s)	46.78	50.20	50.20	13.19	13.19	25.10	25.10	6.80	6.59	6.59
h (kJ/kg)	857.0	864.1	1511.5	864.1	723.8	1510.0	2661.8	864.1	864.1	2798.6
quality	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	1.00

Stream	*71*	*72*	*73*	*74*	*75*	*76*	*77*	*78*	*79*	*80*
T (C)	350	350	362	560	350	363	363	94	103	135
p (bar)	41.00	41.00	30.50	29.00	41.00	30.50	30.50	19.50	32.50	32.00
m (kg/s)	6.59	4.24	112.90	112.90	2.35	141.77	33.11	90.39	94.49	94.49
h (kJ/kg)	3089.6	3089.6	3142.6	3592.1	3089.6	3144.6	3144.6	395.6	435.0	569.8
quality	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00

Stream	*81*	*82*	*83*	*84*	*85*	*86*	*87*
T (C)	134	141	29	29	40	55	130
p (bar)	4.70	3.70	0.04	0.04	6.00	6.00	5.00
m (kg/s)	10.47	10.47	114.90	114.90	152.51	152.51	162.55
h (kJ/kg)	561.7	2734.5	2350.0	120.7	167.6	230.6	546.0
quality	0.00	1.00	0.92	0.00	0.00	0.00	0.00

Table A8.2: Stream report (cont.)

7. GAS CONSTITUENTS

The following table shows the syngas and flue gas composition of the considered IGCC in molar percentages.

Stream #	*1*	*5*	*8*	*12*	*13*	*16*	*17*	*20*
Ar	1.0	1.0	1.0	1.0	1.0	0.66	0.66	0.66
H_2	29.5	27.6	27.6	30.0	30.1	19.03	44.90	54.22
O_2	-	-	-	-	-	-	-	-
N_2	3.6	3.4	3.4	3.7	3.7	2.31	2.31	2.31
H_2O	1.8	8.4	8.4	0.3	0.3	36.95	11.08	1.76
H_2S	0.3	0.3	0.3	0.3	0.0	0.00	0.00	0.00
SO_2	-	-	-	-	-	0.00	0.00	0.00
CO	62.7	58.6	58.6	63.7	63.9	40.42	14.55	5.23
CO_2	1.0	0.9	0.9	1.0	1.0	0.63	26.49	35.82
COS	0.0	0.0	0.0	0.0	0.0	-	-	-
CH_x	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00

Stream #	*21*	*22*	*23*	*24*	*25*	*26*	*28*	*29*
Ar	0.66	1.03	0.96	0.62	0.90	0.90	0.00	0.00
H_2	54.85	85.24	79.48	41.14	0.00	0.00	0.33	0.33
O_2	-	-	-	0.34	9.25	10.14	-	-
N_2	2.34	3.65	3.4	49.54	74.37	74.62	0.00	0.00
H_2O	0.61	0.84	7.54	3.90	14.11	13.07	0.20	0.20
H_2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO_2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	5.29	8.11	7.56	3.91	0.00	0.00	0.23	0.23
CO_2	36.24	1.13	1.05	0.54	1.37	1.27	99.24	99.24
COS	-	0.00	0.00	0.00	0.00	0.00	-	-
CH_x	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table A8.3: Gas constituents

Stream #	*30*	*31*	*36*	*38*
Ar	0.00	0.9	0.2	3.5
H_2	0.33	0.0	-	-
O_2	-	20.81	0.7	95.1
N_2	0.00	77.55	99.0	1.4
H_2O	0.20	6.79	0.0	0.0
H_2S	0.00	0.0	-	-
SO_2	0.00	-	-	-
CO	0.23	0.0	-	-
CO_2	99.24	0.0	0.0	0.0
COS	-	0.0	-	-
CH_x	0.00	0.0	-	-

Table A8.3: Gas constituents (cont.)

8. ENERGY BALANCE

Energy Balance		
Fuel Consumption LHV	1001.76 MW	
Gas Turbine	282.63 MW	
GT Shaft power		*287.62 MW*
GT remaining losses		*-1.54 MW*
GT Generator losses		*-3.54 MW*
Net GT power		*282.63 MW*
Steam turbine	183.94 MW	
ST Shaft power		*187.69 MW*
ST Generator losses		*-3.75 MW*
ST Generator output		*183.94 MW*
Balance of plant losses	-7.65 MW	
Boiler feedwater pumps		*-3.14 MW*
Cooling water pumps		*-2.64 MW*
Remaining losses		*-1.88 MW*
BOP losses		*-7.65 MW*
Air Separation Unit	-37.82 MW	
Air compressor power		*-3.98 MW*
Oxygen compressor		*-9.21 MW*
Nitrogen compressor		*-24.63 MW*
ASU power loss		*-37.82 MW*
Gasifier losses	-8.50 MW	
Recycle compressor		*-1.63 MW*
Saturator pumps		*-0.18 MW*
Coal treatment		*-1.75 MW*
Aux. power		*-4.95 MW*
Gasifier losses		*-8.50 MW*
CO2 recovery unit	-30.17	
Absorber recycle pump		*-8.03 MW*
Hydraulic turbine		*3.61 MW*
CO2 compressor		*-25.17 MW*
Cooling water pumps		*-0.59 MW*
CO2 recovery losses		*-30.17 MW*
Total plant net power	382.42 MW	
Efficiency	38.18%	

Table A8.4: Results energy balance

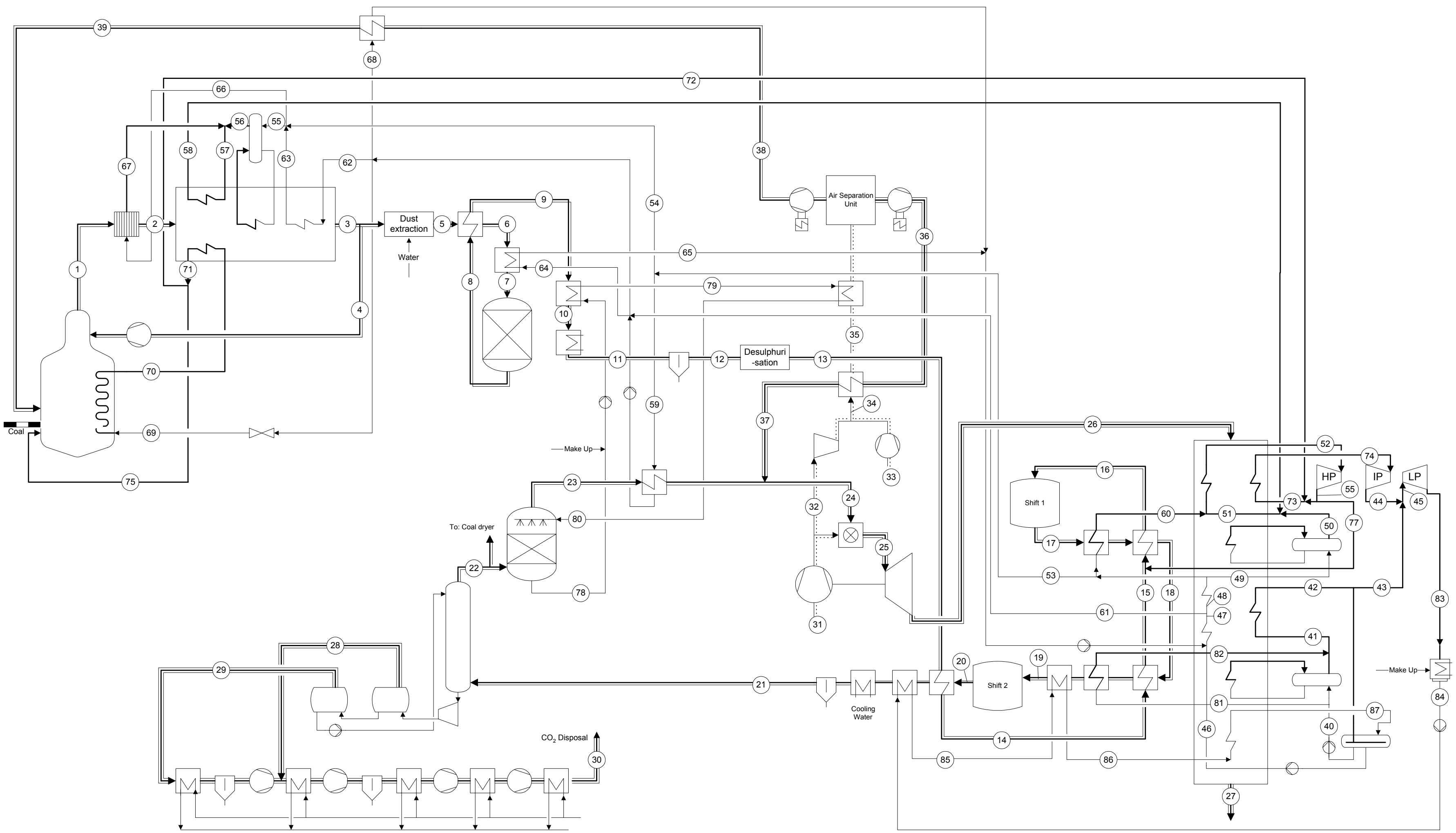
Coal
Dust extraction
Water
Air Separation Unit
Desulphuri -sation
Make Up
To: Coal dryer
Shift 1
Shift 2
Cooling Water
HP
IP
LP
Make Up
CO_2 Disposal

Figure A8.1

CASH FLOW PROJECTION
CASE FOR ALL CASES,
DISCOUNT RATE 10%

IEA
THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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CASH FLOW PROJECTION
FOR ALL CASES,
DISCOUNT RATE 5%

IEA
THE ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

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Efficiency summary	G1wo	G1w	G2w	G3w	C1wo	C1w	C2wo	C2w
Fuel input (MWth)	1405.53	1405.53	1695.77	1393.94	1098.18	1098.18	880	1001.76
Net power (MWe)	789.86	662.67	819.83	665.8	500.65	362.24	407.76	382.42
Net efficiency	56.20%	47.15%	48.35%	47.76%	45.59%	32.99%	46.34%	38.17%
confidence limits	0.0%	2.0%	5.0%	2.0%	0.0%	2.0%	1.0%	5.0%
Specific costs (US$/KWe)								
power generating system	351.07	418.46	338.24	416.49	866.02	1196.93	1236.36	1437.86
CO2 capture system	0.00	192.84	362.15	136.56	0.00	254.69	0.00	278.44
CO2 compression system	0.00	44.33	35.93	43.58	0.00	94.86	0.00	72.92
	351.07	655.63	736.32	596.62	866.02	1546.49	1236.36	1789.23
# operators	9	11	13	11	13	15	20	24
Fuel price US$/GJ	2	2	2	2	1.5	1.5	1.5	1.5
Coal Handling CAPEX (%)	0%	0%	0%	0%	46%	36%	35%	28%
Corr. Net power (MWe)	500	500	500	500	500	500	500	500
Net efficiency	56.20%	47.15%	48.35%	47.76%	45.59%	32.99%	46.34%	38.17%
Corr. Fuel input	889.68	1060.45	1034.13	1046.90	1096.73	1515.82	1078.98	1309.93
kWh price (US$/kWh)	0.0191	0.0275	0.0288	0.0263	0.0300	0.0498	0.0371	0.0528
NPV	M$ 0.0	M$ 0.0	M$ 0.0	M$ (0.0)	M$ 0.0	M$ 0.0	M$ 0.0	M$ 0.0
Kwh price breakdown								
Cost of Fuel	67.0%	55.5%	51.6%	57.2%	39.5%	32.9%	31.4%	26.8%
Capital Expenditures	22.2%	29.2%	32.1%	27.8%	38.3%	42.1%	44.5%	47.1%
Other costs	10.8%	15.3%	16.2%	15.0%	22.3%	25.0%	24.1%	26.2%

LABOUR		
Labour costs	38000	US$/year
Supervision factor	20%	
Admin. + Overhead factor	60%	
# shifts	4	
Discount Rate	5%	
hours/year	8000	
commisioning time	3	months
Insurance	1%	p.a. of overnight construction costs
Capital expenditures		
Land purchase; surveys	5%	
specific services	1%	
fees	2%	
contingencies	10%	
Gas price	2	US$/GJ
Coal price	1.5	US$/GJ
MAINTENANCE		
Coal Handling equipment	4%	pa. of CAPEX
Other equipment	2%	pa. of CAPEX
Fuel price sensitivity factor	100%	

IEA **Cash flow projection for case: G1wo**

Production			
Fuel Input LHV	1405.53 MWth	Fuel price sens. factor	100%
Net Efficiency	56.20%		
Net power Output	789.86 MWe		
Fuel price	2.00 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	2% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Operating costs (per year)		
Fuel costs	M$	(81.0)
Maintenenance exp.	M$	(5.5)
Waste disposal	M$	-
Chemicals+Consumables	M$	(1.2)
Insurance	M$	(2.8)
Working capital		
15 day chemical storage	M$	(0.1)
coal storage	M$	-
Total woking capital	M$	(0.1)
Maintenance		
Coal handling Cap. Ex.	M$	-
Remaining Cap. Ex.	M$	277.3
Coal handling Maint. Exp.	M$	-
Remaining Maint. Exp.	M$	5.5
Total Maintenance Exp.	M$	5.5

Labour cost		
# operators	9	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	1.4
Supervision	M$	0.3
Administration	M$	0.8
Total Labour cost	M$	2.5
Revenues		
NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost	0.0191 US$ / kWh	
Revenues / year	M$	120.7

Kwh price breakdown	(%)
Cost of Fuel	67.0%
Capital Expenditures	22.2%
Other costs	10.8%
total	100%

Specific costs		
power generating system (a)	351.1	US$/KWe
CO2 capture system (b)	-	US$/KWe
CO2 compression system (c)	-	US$/KWe

Capital Expenditures		power (a)	capture (b)	compr (c)	total
Overnight construction costs		M$ 277.3	M$ -	M$ -	M$ 277.3
Land purchase; surveys	5%	M$ 13.9	M$ -	M$ -	M$ 13.9
specific services	1%	M$ 2.8	M$ -	M$ -	M$ 2.8
fees	2%	M$ 5.5	M$ -	M$ -	M$ 5.5
contingencies	10%	M$ 27.7	M$ -	M$ -	M$ 27.7
confidence limits	0%	M$ -	M$ -	M$ -	M$ -
Total installed cost		M$ 327.2	M$ -	M$ -	M$ 327.2

Decomissioning costs M$ (13.9)

year	1	2	3	4	5	6	7	8	9	10	11	12	13	26	27	28
load factor			68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Expenditure factor (natural gas fired plant)	40%	60%														
Revenues	M$ -	M$ -	M$ 81.5	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	M$ 108.7	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ (54.6)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	
Maintenance	M$ -	M$ -	M$ (3.7)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	
Labour	M$ -	M$ -	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	M$ (2.5)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Chemicals & Consumables	M$ -	M$ -	M$ (0.8)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	M$ (1.1)	
Insurance	M$ -	M$ -	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	M$ (2.8)	
Fixed Capital Expenditures	M$ (130.9)	M$ (196.3)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ (0.1)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 0.1
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (13.9)
Total cash flow	*M$ (130.9)*	*M$ (196.3)*	*M$ 17.0*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ 24.5*	*M$ (13.8)*

IEA **Cash flow projection for case: G1w**

Production				
Fuel Input LHV	1405.53 MWth	Fuel price sens. factor	100%	
Net Efficiency	47.15%			
Net power Output	662.67 MWe			
Fuel price	2.00 US$/GJ			
hours/year	8000			
Maintenance (p.a.)	2% installed plant cost			
Commissioning time	3 months			
Insurance fee	1% p.a. installed plant cost			

Operating costs (per year)		
Fuel costs	M$	(81.0)
Maintenence exp.	M$	(8.7)
Waste disposal	M$	-
Chemicals+Consumables	M$	(4.8)
Insurance	M$	(4.3)
Working capital		
15 day chemical storage	M$	(0.2)
coal storage	M$	-
Total woking capital	M$	(0.2)
Maintenance		
Coal handling Cap. Ex.	M$	-
Remaining Cap. Ex.	M$	434.5
Coal handling Maint. Exp.	M$	-
Remaining Maint. Exp.	M$	8.7
Total Maintenance Exp.	M$	8.7

Labour cost		
# operators	11	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	1.7
Supervision	M$	0.3
Administration	M$	1.0
Total Labour cost	M$	3.0
Revenues		
NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost		0.0275 US$ / kWh
Revenues / year	M$	145.9

Kwh price breakdown	(%)
Cost of Fuel	55.5%
Capital Expenditures	29.2%
Other costs	15.3%
total	100%

Specific costs		
power generating system (a)	418.5	US$/KWe
CO2 capture system (b)	192.8	US$/KWe
CO2 compression system (c)	44.3	US$/KWe

Capital Expenditures		power (a)		capture (b)		compr (c)		total	
Overnight construction costs		M$	277.3	M$	127.8	M$	29.4	M$	434.5
Land purchase; surveys	5%	M$	13.9	M$	6.4	M$	1.5	M$	21.7
specific services	1%	M$	2.8	M$	1.3	M$	0.3	M$	4.3
fees	2%	M$	5.5	M$	2.6	M$	0.6	M$	8.7
contingencies	10%	M$	27.7	M$	12.8	M$	2.9	M$	43.4
confidence limits	2%	M$	5.5	M$	2.6	M$	0.6	M$	8.7
Total installed cost		M$	332.8	M$	153.4	M$	35.2	M$	521.4

Decomissioning costs M$ (21.7)

year	1	2	3	4	5	6	7	8	9	10	11	12	13	26	27	28
load factor			68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Expenditure factor (natural gas fired plant)	40%	60%														
Revenues	M$ -	M$ -	M$ 98.5	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	M$ 131.3	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ (54.6)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	M$ (72.9)	
Maintenance	M$ -	M$ -	M$ (5.9)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	M$ (7.8)	
Labour	M$ -	M$ -	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Chemicals & Consumables	M$ -	M$ -	M$ (3.2)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	
Insurance	M$ -	M$ -	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	
Fixed Capital Expenditures	M$ (208.5)	M$ (312.8)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ (0.2)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 0.2
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (21.7)
Total cash flow	*M$ (208.5)*	*M$ (312.8)*	*M$ 27.2*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ 39.0*	*M$ (21.5)*

IEA **Cash flow projection for case: G2w**

Production

Fuel Input LHV	1695.77 MWth	Fuel price sens. factor	100%
Net Efficiency	48.35%		
Net power Output	819.83 MWe		
Fuel price	2.00 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	2% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Specific costs

power generating system (a)	338.2	US$/KWe
CO2 capture system (b)	362.2	US$/KWe
CO2 compression system (c)	35.9	US$/KWe

Capital Expenditures		power (a)	capture (b)	compr (c)	total
Overnight construction costs		M$ 277.3	M$ 296.9	M$ 29.5	M$ 603.7
Land purchase; surveys	5%	M$ 13.9	M$ 14.8	M$ 1.5	M$ 30.2
specific services	1%	M$ 2.8	M$ 3.0	M$ 0.3	M$ 6.0
fees	2%	M$ 5.5	M$ 5.9	M$ 0.6	M$ 12.1
contingencies	10%	M$ 27.7	M$ 29.7	M$ 2.9	M$ 60.4
confidence limits	5%	M$ 13.9	M$ 14.8	M$ 1.5	M$ 30.2
Total installed cost		M$ 341.1	M$ 365.2	M$ 36.2	M$ 742.5

Decommissioning costs M$ (30.2)

Operating costs (per year)

Fuel costs	M$	(97.7)
Maintenenance exp.	M$	(12.1)
Waste disposal	M$	-
Chemicals+Consumables	M$	(6.9)
Insurance	M$	(6.0)

Working capital

15 day chemical storage	M$	(0.3)
Catalyst	M$	(4.8)
Total woking capital	M$	(5.1)

Maintenance

Coal handling Cap. Ex.	M$	-
Remaining Cap. Ex.	M$	603.7
Coal handling Maint. Exp.	M$	-
Remaining Maint. Exp.	M$	12.1
Total Maintenance Exp.	M$	12.1

Labour cost

# operators	13	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	2.0
Supervision	M$	0.4
Administration	M$	1.2
Total Labour cost	M$	3.6

Revenues

NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost		0.0288 US$ / kWh
Revenues / year	M$	189.1

Kwh price breakdown	(%)
Cost of Fuel	51.6%
Capital Expenditures	32.1%
Other costs	16.2%
total	100%

year	1	2	3	4	5	6	7	8	9	10	11	12	13	26	27	28
load factor			68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Expenditure factor (natural gas fired plant)	40%	60%														
Revenues	M$ -	M$ -	M$ 127.7	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	M$ 170.2	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ (65.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	M$ (87.9)	
Maintenance	M$ -	M$ -	M$ (8.1)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	M$ (10.9)	
Labour	M$ -	M$ -	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Chemicals & Consumables	M$ -	M$ -	M$ (4.6)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	M$ (6.2)	
Insurance	M$ -	M$ -	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	M$ (6.0)	
Fixed Capital Expenditures	M$ (297.0)	M$ (445.5)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ (5.1)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 5.1
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (30.2)
Total cash flow	*M$ (297.0)*	*M$ (445.5)*	*M$ 34.3*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ 55.7*	*M$ (25.1)*

IEA **Cash flow projection for case: G3w**

Production

Fuel Input LHV	1393.94 MWth	Fuel price sens. factor	100%
Net Efficiency	47.76%		
Net power Output	665.80 MWe		
Fuel price	2.00 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	2% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Specific costs

power generating system (a)	416.5	US$/KWe
CO2 capture system (b)	136.6	US$/KWe
CO2 compression system (c)	43.6	US$/KWe

Capital Expenditures		power (a)	capture (b)	compr (c)	total
Overnight construction costs		M$ 277.3	M$ 90.9	M$ 29.0	M$ 397.2
Land purchase; surveys	5%	M$ 13.9	M$ 4.5	M$ 1.5	M$ 19.9
specific services	1%	M$ 2.8	M$ 0.9	M$ 0.3	M$ 4.0
fees	2%	M$ 5.5	M$ 1.8	M$ 0.6	M$ 7.9
contingencies	10%	M$ 27.7	M$ 9.1	M$ 2.9	M$ 39.7
confidence limits	2%	M$ 5.5	M$ 1.8	M$ 0.6	M$ 7.9
Total installed cost		M$ 332.8	M$ 109.1	M$ 34.8	M$ 476.7

Decommissioning costs M$ (19.9)

Operating costs (per year)

Fuel costs	M$	(80.3)
Maintenence exp.	M$	(7.9)
Waste disposal	M$	-
Chemicals+Consumables	M$	(4.7)
Insurance	M$	(4.0)

Working capital

15 day chemical storage	M$	(0.2)
coal storage	M$	-
Total woking capital	M$	(0.2)

Maintenance

Coal handling Cap. Ex.	M$	-
Remaining Cap. Ex.	M$	397.2
Coal handling Maint. Exp.	M$	-
Remaining Maint. Exp.	M$	7.9
Total Maintenance Exp.	M$	7.9

Labour cost

# operators	11	
Salary	38000	US$/year
# shifts	4	
Supervision	20%	direct cost
Adminstr.	60%	direct cost

Direct labour costs	M$	1.7
Supervision	M$	0.3
Administration	M$	1.0
Total Labour cost	M$	3.0

Revenues

NPV	M$	(0.0)
Discount Rate		**5.00%**
Electricity production cost		0.0263 US$ / kWh
Revenues / year	M$	140.3

Kwh price breakdown	(%)
Cost of Fuel	57.2%
Capital Expenditures	27.8%
Other costs	15.0%
total	100%

year	1	2	3	4	5	6	7	8	9	10	11	12	13	26	27	28
load factor			68%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Expenditure factor (natural gas fired plant)	40%	60%														
Revenues	M$ -	M$ -	M$ 94.7	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	M$ 126.3	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ (54.2)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	M$ (72.3)	
Maintenance	M$ -	M$ -	M$ (5.4)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	M$ (7.2)	
Labour	M$ -	M$ -	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	M$ (3.0)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Chemicals & Consumables	M$ -	M$ -	M$ (3.2)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	
Insurance	M$ -	M$ -	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	M$ (4.0)	
Fixed Capital Expenditures	M$ (190.7)	M$ (286.0)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ (0.2)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 0.2
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (19.9)
Total cash flow	*M$ (190.7)*	*M$ (286.0)*	*M$ 24.8*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ 35.6*	*M$ (19.6)*

IEA **Cash flow projection for case: C1wo**

Production			
Fuel Input LHV	1098.16 MWth	Fuel price sens. factor	100%
Net Efficiency	45.59%		
Net power Output	500.65 MWe		
Fuel price	1.50 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	4% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Operating costs (per year)		
Fuel costs	M$	(47.4)
Maintenenance exp.	M$	(12.7)
Waste disposal	M$	(1.9)
Chemicals+Consumables	M$	(2.0)
Insurance	M$	(4.3)
Working capital		
15 day chemical storage	M$	(0.1)
coal storage	M$	(1.8)
Total woking capital	M$	(1.9)
Maintenance		
Coal handling Cap. Ex.	M$	199.4
Remaining Cap. Ex.	M$	234.1
Coal handling Maint. Exp.	M$	8.0
Remaining Maint. Exp.	M$	4.7
Total Maintenance Exp.	M$	12.7

Labour cost		
# operators	13	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	2.0
Supervision	M$	0.4
Administration	M$	1.2
Total Labour cost	M$	3.6
Revenues		
NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost		0.0300 US$ / kWh
Revenues / year	M$	120.2

Kwh price breakdown	(%)
Cost of Fuel	39.5%
Capital Expenditures	38.3%
Other costs	22.3%
total	100%

Specific costs		
power generating system (a)	866.0	US$/KWe
CO2 capture system (b)	-	US$/KWe
CO2 compression system (c)	-	US$/KWe

Capital Expenditures		power (a)	capture (b)	compr (c)	total
Overnight construction costs		M$ 433.6	M$ -	M$ -	M$ 433.6
Land purchase; surveys	5%	M$ 21.7	M$ -	M$ -	M$ 21.7
specific services	1%	M$ 4.3	M$ -	M$ -	M$ 4.3
fees	2%	M$ 8.7	M$ -	M$ -	M$ 8.7
contingencies	10%	M$ 43.4	M$ -	M$ -	M$ 43.4
confidence limits	0%	M$ -	M$ -	M$ -	M$ -
Total installed cost		M$ 511.6	M$ -	M$ -	M$ 511.6

Decomissioning costs M$ (21.7)

year	1	2	3	4	5	6	7	8	9	10	11	12	13	27	28	29
load factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Expenditure factor (coal fired plant)	20%	45%	35%													
Expenditure factor (chemical plant)	40%	60%														
Revenues	M$ -	M$ -	M$ -	M$ 54.1	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	M$ 102.2	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ -	M$ (21.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	
Maintenance	M$ -	M$ -	M$ -	M$ (5.7)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	M$ (10.8)	
Labour	M$ -	M$ -	M$ -	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	M$ (3.6)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ (0.8)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	
Chemicals & Consumables	M$ -	M$ -	M$ -	M$ (0.9)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	M$ (1.7)	
Insurance	M$ -	M$ -	M$ -	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	M$ (4.3)	
Fixed Capital Expenditures	M$ (102.3)	M$ (230.2)	M$ (179.1)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ -	M$ (1.9)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 1.9
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (21.7)
Total cash flow	*M$ (102.3)*	*M$ (230.2)*	*M$ (179.1)*	*M$ 15.5*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ 39.9*	*M$ (19.8)*

IEA **Cash flow projection for case: C1w**

Production

Fuel Input LHV	1098.18 MWth	Fuel price sens. factor	100%
Net Efficiency	32.99%		
Net power Output	362.24 MWe		
Fuel price	1.50 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	4% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Operating costs (per year)

Fuel costs	M$	(47.4)
Maintenence exp.	M$	(15.2)
Waste disposal	M$	(1.9)
Chemicals+Consumables	M$	(6.3)
Insurance	M$	(5.6)

Working capital

15 day chemical storage	M$	(0.3)
coal storage	M$	(1.8)
Total woking capital	M$	(2.1)

Maintenance

Coal handling Cap. Ex.	M$	201.7
Remaining Cap. Ex.	M$	358.5
Coal handling Maint. Exp.	M$	8.1
Remaining Maint. Exp.	M$	7.2
Total Maintenance Exp.	M$	15.2

Labour cost

# operators	15	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	2.3
Supervision	M$	0.5
Administration	M$	1.4
Total Labour cost	M$	4.1

Revenues

NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost	0.0498	US$ / kWh
Revenues / year	M$	144.3

Kwh price breakdown (%)

Cost of Fuel	32.9%
Capital Expenditures	42.1%
Other costs	25.0%
total	100%

Specific costs

power generating system (a)	1,196.9	US$/KWe
CO2 capture system (b)	254.7	US$/KWe
CO2 compression system (c)	94.9	US$/KWe

Capital Expenditures		power (a)	capture (b)	compr (c)	total
Overnight construction costs		M$ 433.6	M$ 92.3	M$ 34.4	M$ 560.2
Land purchase; surveys	5%	M$ 21.7	M$ 4.6	M$ 1.7	M$ 28.0
specific services	1%	M$ 4.3	M$ 0.9	M$ 0.3	M$ 5.6
fees	2%	M$ 8.7	M$ 1.8	M$ 0.7	M$ 11.2
contingencies	10%	M$ 43.4	M$ 9.2	M$ 3.4	M$ 56.0
confidence limits	2%	M$ 8.7	M$ 1.8	M$ 0.7	M$ 11.2
Total installed cost		M$ 520.3	M$ 110.7	M$ 41.2	M$ 672.2

Decomissioning costs M$ (28.0)

year	1	2	3	4	5	6	7	8	9	10	11	12	13	27	28	29
load factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Expenditure factor (coal fired plant)	20%	45%	35%													
Expenditure factor (chemical plant)	40%	60%														
Revenues	M$ -	M$ -	M$ -	M$ 64.9	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	M$ 122.7	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ -	M$ (21.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	M$ (40.3)	
Maintenance	M$ -	M$ -	M$ -	M$ (6.9)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	M$ (13.0)	
Labour	M$ -	M$ -	M$ -	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	M$ (4.1)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ (0.8)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	M$ (1.6)	
Chemicals & Consumables	M$ -	M$ -	M$ -	M$ (2.9)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	M$ (5.4)	
Insurance	M$ -	M$ -	M$ -	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	M$ (5.6)	
Fixed Capital Expenditures	M$ (164.8)	M$ (325.3)	M$ (182.1)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ -	M$ (2.1)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 2.1
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (28.0)
Total cash flow	*M$ (164.8)*	*M$ (325.3)*	*M$ (182.1)*	*M$ 21.2*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ 52.7*	*M$ (25.9)*

IEA **Cash flow projection for case: C2wo**

Production			
Fuel Input LHV	879.93 MWth	Fuel price sens. factor	100%
Net Efficiency	46.34%		
Net power Output	407.76 MWe		
Fuel price	1.50 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	4% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Operating costs (per year)		
Fuel costs	M$	(38.0)
Maintenenance exp.	M$	(13.6)
Waste disposal	M$	(0.4)
Chemicals+Consumables	M$	(1.7)
Insurance	M$	(5.0)
Working capital		
15 day chemical storage	M$	(0.1)
coal storage	M$	(1.5)
Total woking capital	M$	(1.5)
Maintenance		
Coal handling Cap. Ex.	M$	176.4
Remaining Cap. Ex.	M$	327.7
Coal handling Maint. Exp.	M$	7.1
Remaining Maint. Exp.	M$	6.6
Total Maintenance Exp.	M$	13.6

Labour cost		
# operators	20	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	3.0
Supervision	M$	0.6
Administration	M$	1.8
Total Labour cost	M$	5.5
Revenues		
NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost	0.0371	US$ / kWh
Revenues / year	M$	121.1

Kwh price breakdown	(%)
Cost of Fuel	31.4%
Capital Expenditures	44.5%
Other costs	24.1%
total	100%

Specific costs			
power generating system	(a)	1,236.4	US$/KWe
CO2 capture system	(b)	-	US$/KWe
CO2 compression system	(c)	-	US$/KWe

Capital Expenditures		power (a)		capture (b)		compr (c)		total	
Overnight construction costs		M$	504.1	M$	-	M$	-	M$	504.1
Land purchase; surveys	5%	M$	25.2	M$	-	M$	-	M$	25.2
specific services	1%	M$	5.0	M$	-	M$	-	M$	5.0
fees	2%	M$	10.1	M$	-	M$	-	M$	10.1
contingencies	10%	M$	50.4	M$	-	M$	-	M$	50.4
confidence limits	1%	M$	5.0	M$	-	M$	-	M$	5.0
Total installed cost		M$	599.9	M$	-	M$	-	M$	599.9

Decomissioning costs M$ (25.2)

year	1	2	3	4	5	6	7	8
load factor				45%	85%	85%	85%	85%
Expenditure factor (coal fired plant)	20%	45%	35%					
Expenditure factor (chemical plant)	40%	60%						
Revenues	M$ -	M$ -	M$ -	M$ 54.5	M$ 102.9	M$ 102.9	M$ 102.9	M$ 102.9
Operating Costs								
Fossil Fuel costs	M$ -	M$ -	M$ -	M$ (17.1)	M$ (32.3)	M$ (32.3)	M$ (32.3)	M$ (32.3)
Maintenance	M$ -	M$ -	M$ -	M$ (6.1)	M$ (11.6)	M$ (11.6)	M$ (11.6)	M$ (11.6)
Labour	M$ -	M$ -	M$ -	M$ (5.5)	M$ (5.5)	M$ (5.5)	M$ (5.5)	M$ (5.5)
Solid waste disposal	M$ -	M$ -	M$ -	M$ (0.2)	M$ (0.3)	M$ (0.3)	M$ (0.3)	M$ (0.3)
Chemicals & Consumables	M$ -	M$ -	M$ -	M$ (0.8)	M$ (1.4)	M$ (1.4)	M$ (1.4)	M$ (1.4)
Insurance	M$ -	M$ -	M$ -	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)
Fixed Capital Expenditures	M$ (120.0)	M$ (270.0)	M$ (210.0)	M$ -	M$ -	M$ -	M$ -	M$ -
Working Capital	M$ -	M$ -	M$ -	M$ (1.5)	M$ -	M$ -	M$ -	M$ -
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -
Total cash flow	*M$ (120.0)*	*M$ (270.0)*	*M$ (210.0)*	*M$ 18.3*	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*

year	9	10	11	12	13	27	28	29
load factor	85%	85%	85%	85%	85%	85%	85%	
Expenditure factor (coal fired plant)								
Expenditure factor (chemical plant)								
Revenues	M$ 102.9	M$ 102.9	M$ 102.9	M$ 102.9	M$ 102.9	M$ 102.9	M$ 102.9	
Operating Costs								
Fossil Fuel costs	M$ (32.3)	M$ (32.3)	M$ (32.3)	M$ (32.3)	M$ (32.3)	M$ (32.3)	M$ (32.3)	
Maintenance	M$ (11.6)	M$ (11.6)	M$ (11.6)	M$ (11.6)	M$ (11.6)	M$ (11.6)	M$ (11.6)	
Labour	M$ (5.5)	M$ (5.5)	M$ (5.5)	M$ (5.5)	M$ (5.5)	M$ (5.5)	M$ (5.5)	
Solid waste disposal	M$ (0.3)	M$ (0.3)	M$ (0.3)	M$ (0.3)	M$ (0.3)	M$ (0.3)	M$ (0.3)	
Chemicals & Consumables	M$ (1.4)	M$ (1.4)	M$ (1.4)	M$ (1.4)	M$ (1.4)	M$ (1.4)	M$ (1.4)	
Insurance	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	M$ (5.0)	
Fixed Capital Expenditures	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 1.5
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (25.2)
Total cash flow	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*	*M$ 46.8*	*M$ (23.7)*

IEA **Cash flow projection for case: C2w**

Production			
Fuel Input LHV	1001.89 MWth	Fuel price sens. factor	100%
Net Efficiency	38.17%		
Net power Output	382.42 MWe		
Fuel price	1.50 US$/GJ		
hours/year	8000		
Maintenance (p.a.)	4% installed plant cost		
Commissioning time	3 months		
Insurance fee	1% p.a. installed plant cost		

Operating costs (per year)		
Fuel costs	M$	(43.3)
Maintenence exp.	M$	(17.5)
Waste disposal	M$	(0.4)
Chemicals+Consumables	M$	(7.1)
Insurance	M$	(6.8)
Working capital		
15 day chemical storage	M$	(0.3)
coal storage	M$	(1.7)
Total woking capital	M$	(2.0)
Maintenance		
Coal handling Cap. Ex.	M$	191.6
Remaining Cap. Ex.	M$	492.7
Coal handling Maint. Exp.	M$	7.7
Remaining Maint. Exp.	M$	9.9
Total Maintenance Exp.	M$	17.5

Labour cost		
# operators	24	
Salary	38000 US$/year	
# shifts	4	
Supervision	20% direct cost	
Adminstr.	60% direct cost	
Direct labour costs	M$	3.6
Supervision	M$	0.7
Administration	M$	2.2
Total Labour cost	M$	6.6
Revenues		
NPV	M$	0.0
Discount Rate		**5.00%**
Electricity production cost	0.0528 US$ / kWh	
Revenues / year	M$	161.7

Kwh price breakdown	(%)
Cost of Fuel	26.8%
Capital Expenditures	47.1%
Other costs	26.2%
total	100%

Specific costs		
power generating system (a)	1,437.9	US$/KWe
CO2 capture system (b)	278.4	US$/KWe
CO2 compression system (c)	72.9	US$/KWe

Capital Expenditures		power (a)	capture (b)	compr (c)	total
Overnight construction costs		M$ 549.9	M$ 106.5	M$ 27.9	M$ 684.2
Land purchase; surveys	5%	M$ 27.5	M$ 5.3	M$ 1.4	M$ 34.2
specific services	1%	M$ 5.5	M$ 1.1	M$ 0.3	M$ 6.8
fees	2%	M$ 11.0	M$ 2.1	M$ 0.6	M$ 13.7
contingencies	10%	M$ 55.0	M$ 10.6	M$ 2.8	M$ 68.4
confidence limits	5%	M$ 27.5	M$ 5.3	M$ 1.4	M$ 34.2
Total installed cost		M$ 676.3	M$ 131.0	M$ 34.3	M$ 841.6

Decomissioning costs M$ (34.2)

year	1	2	3	4	5	6	7	8	9	10	11	12	13	27	28	29
load factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Expenditure factor (coal fired plant)	20%	45%	35%													
Expenditure factor (chemical plant)	40%	60%														
Revenues	M$ -	M$ -	M$ -	M$ 72.8	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	M$ 137.4	
Operating Costs																
Fossil Fuel costs	M$ -	M$ -	M$ -	M$ (19.5)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	M$ (36.8)	
Maintenance	M$ -	M$ -	M$ -	M$ (7.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	M$ (14.9)	
Labour	M$ -	M$ -	M$ -	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	M$ (6.6)	
Solid waste disposal	M$ -	M$ -	M$ -	M$ (0.2)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	M$ (0.4)	
Chemicals & Consumables	M$ -	M$ -	M$ -	M$ (3.2)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	M$ (6.1)	
Insurance	M$ -	M$ -	M$ -	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	M$ (6.8)	
Fixed Capital Expenditures	M$ (201.4)	M$ (403.5)	M$ (236.7)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	
Working Capital	M$ -	M$ -	M$ -	M$ (2.0)	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ 2.0
Decomissioning Cost	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ -	M$ (34.2)
Total cash flow	*M$ (201.4)*	*M$ (403.5)*	*M$ (236.7)*	*M$ 26.6*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ 65.9*	*M$ (32.2)*

TECHNICAL REFERENCE DOCUMENT

FOR

ASSESSMENT OF LEADING TECHNOLOGY OPTIONS FOR ABATEMENT OF CO_2 EMISSIONS

IEA GREENHOUSE GAS R&D PROGRAMME

UNITED KINGDOM

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1. DESIGN CASES

The following power generation processes will be evaluated:

Natural gas based power generation

$G1_{w/o}$: Power generation in a combined cycle

$G1_{w}$: Power generation in a combined cycle with carbon dioxide removal from the flue gases using an amine-based solvent

$G2_{w}$: Conversion of natural gas to a synthesis gas followed by CO shift and CO_2 removal. The hydrogen-rich product can be used in a combined cycle to produce electricity. For the conversion of natural gas to a synthesis gas and for the removal of CO_2, several processes are available. Stork Engineering Consultancy will suggest an appropriate scheme. The final selection will be made in close co-operation with IEA-GHG. In the past Stork Engineering Consultancy has performed several evaluations with regard to this pre-combustion decarbonisation processes. The results from this evaluation will be used to make a conscious choice.

$G3_{w}$: Partial flue gas recycling in natural gas fired combined cycles. By re-circulating part of the flue gasses to the gas turbine compressor, the CO_2 concentration will increase which facilitates the CO_2 removal, especially in terms of energy consumption.

Coal based power generation

$C1_{w/o}$: Power generation in a supercritical steam cycle

$C1_{w}$: Power generation in a supercritical steam cycle combined with carbon dioxide removal from the flue gases using an amine-based solvent

$C2_{w/o}$: Power generation in an integrated coal gasification combined cycle

$C2_{w}$: Power generation in an integrated coal gasification combined cycle followed by CO shift and CO_2 capture. The hydrogen-rich product can be used in a combined cycle to produce electricity.

2. TECHNICAL DATA

2.1 FUEL SPECIFICATIONS

COAL

The coal specification is based on an open-cut coal from Eastern Australia

Proximate analysis:	*weight %*
coal (dry, ash free)	78.3
ash	12.2
moisture	9.5

Ultimate analysis: Dry, ash free	*weight %*
Carbon	82.5
Hydrogen	5.6
Oxygen	9.0
Nitrogen	1.8
Sulphur	1.1
Chlorine	0.03

Ash analysis:	*weight %*
SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7

Table A11.1: Coal characteristics

HHV	27.06 MJ/kg
LHV	25.87 MJ/kg
Hardgrove index	45
Ash fusion point (reducing atmosphere)	1350 °C

Table A11.1: Coal characteristics (cont.)

Natural Gas

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves

Component	*volume %*
Methane	83.9
Ethane	9.2
Propane	3.3
Butane +	1.4
Carbon-dioxide	1.8
Nitrogen	0.4
Sulphur (as H_2S)	4 mg/Nm^3
Lower Heating Value	46.899 MJ/kg

Table A11.2: Natural gas characteristics

2.2 SITE CONDITIONS

The plant will be located on the NE coast of The Netherlands at a greenfield site with no special civil works implications.

Ambient air conditions	
Temperature	9 °C
Relative humidity	60%
pressure	1.013 bar

Table A11.3: Site conditions

2.3 COOLING WATER

Indirect sea water cooling will be used at the following sea water conditions:

Sea water cooling conditions	
Summer average inlet temperature	12 °C
Max. temperature rise	7 °C
Salinity	22g/l

Table A11.4: Cooling water assumptions

2.4 EMISSIONS

Emission Limits	
Particulate matter	< 25 mg/Nm^3
NO_x	< 200 mg/Nm^3
SO_2	< 200 mg/Nm^3

Table A11.5: Emission limits

2.5 CO_2 PROCESSING

The levels of CO_2 capture are:

CO_2 capture levels	
Minimum level	80%
Preferred level	85%

Table A11.6: CO_2 capture level

CO_2 will be compressed to 110 bar and liquefied before injection into the transfer pipeline. It will stored in a nearby deep saline reservoir.

2.6 PLANT DATA

Plant data	
Plant size (net)	500 MW_e
Development status	state of the art by 2000
Plant life	25 years
Load factor coal	1^{st} yr 60%
	subs. yrs 85%
Load factor gas	all yrs 90%
Commissioning time	3 months

Table A11.7: Plant data

2.7 HEAT CONTENT

During calculations the Lower Heating Value will always be used.

3. FINANCIAL FACTORS

3.1 DESIGN AND CONSTRUCTION PERIOD

Three years for a coal fired power generation plant. Two years for a natural gas fired combined cycle. Two years for a CO_2 capture plant and 'chemical plants' in general. Two years for an underground CO_2 storage scheme.

Typical 'S-curves of expenditure during construction will be used:

Year	*Coal fired Power Plant*	*Natural Gas fired Power Plant*	*CO_2 capture plant*	*CO_2 storage*
1	20 %	40 %	40 %	40 %
2	45 %	60 %	60 %	60 %
3	35 %	-	-	-

Table A11.8

3.2 COST OF DEBT

Money is required during design, construction an commissioning. For simplicity, all capital requirements will be treated as debt at the same discount rate used to derive capital charges. No allowance for grants, cheap loans etc.

3.3 CAPITAL CHARGES

Discounted cash flow calculations will be expressed at a discount rate of 10 % and, to illustrate sensitivity, at 5%; the resulting capital charge rate will be quoted. All annual expenditures will be assumed to be incurred at the end of the year.

Discount rate	
standard	10 %
for sensitivity study	5 %

Table A11.9

Inflation assumptions will not be made. No allowance will be made for escalation of fuel, labour or other costs relative to each other.

3.4 CURRENCY

The results of the studies will be expressed in 1999 US$. Data obtained in other currencies will be converted at the following rates: (data 23/06/1999)

Exchange rate	*1999 US $*
NL Guilder	0.47
UK pound	1.59
Euro	1.03

Table A11.10

3.5 WORKING CAPITAL

Sufficient storage at rated capacity will be allowed for raw materials, products and consumables (except for natural gas and other gaseous fuels in which case provision should be made for an alternative supply of fuel).

3.6 LOCATION

A cost of 5% of the installed cost (overnight construction) will be assumed to cover land purchase, surveys, general site preparation etc.

3.7 TAXATION AND INSURANCE

Allow 1% p.a. of the installed plant cost (overnight construction) to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments.

Insurance will be taken as 1% p.a. of the installed plant cost (overnight construction).

3.8 FEES

The total contractors and additional fees will be 2% of installed plant cost (overnight construction).
The contractors fees for EPC will form part of the estimate; additional fees include process/patent fees, fees for agents or consultants, legal and planning costs etc.

3.9 CONTINGENCIES

Allow for project contingency costs by adding a factor of 10% to the installed plant cost (overnight construction).

Allowance for estimating error and process unknowns/development will be treated by quoting confidence limits to be agreed on in the section on the economic analysis.
The plant is built on a turnkey basis. The cost of risk should be built into the contractors fees.

3.10 MAINTENANCE

Routing and breakdown maintenance specified as a 5 p.a. of the installed plant cost (overnight construction).

Maintenance cost	*% installed plant cost*
Coal handling plant	4 % p.a.
Gas handling plant	2 % p.a.

Table A11.11

3.11 LABOUR

The cost of maintenance is covered in the preceding paragraph.
Operating labour will work 1960 hr/year in a 4 shift pattern. An allowance of 20 % of the direct labour costs covers supervision. A further 60% of the direct labour costs covers administration and general overheads.

$$total\ costs = direct\ costs + 20\% \cdot direct\ costs + 60\% \cdot direct\ costs$$

3.12 FUELS AND RAW MATERIALS

The cost of coal and natural gas delivered to site are:

Fuel cost	*US $*
Coal	1.5 $ / GJ
Gas	2 $ / GJ

Table A11.12

3.13 DECOMMISSIONING

The costs associated with final shut down of the plant, long term provisions and clearing the sire will be 5 % of installed plant cost (overnight construction).

CONSUMABLES + WASTE PRODUCTS

exchange rate (US$/NLG) 0.47

case	G1wo	G1w	G2w	G3w	C1wo	C1w	C2wo	C2w
limestone MNLG/yr					1.61	1.61		
chemicals for boiler water treatment (MNLG/yr)	0.35	0.35	0.35	0.35	0.88	0.88	0.60	0.67
chemicals for waste water treatment (MNLG/yr)					0.23	0.23		
lubricants (MNLG/yr)	1.15	1.15	1.15	1.15	0.85	0.85	0.80	0.89
potable water (MNLG/yr)	1.15	1.15	1.15	1.15	0.75	0.75	1.75	1.96
Gasification chemicals (MNLG/yr)							0.40	0.46
MEA / Selexol solution + additives (MNLG/yr)		7.52	8.93	7.40		9.20		8.32
Additional water losses (MNLG/yr)			3.02					2.86
total chemicals/ consumables (MNLG/yr)	2.65	10.17	14.60	10.05	4.31	13.51	3.55	15.15
total chemicals/ consumables (MUS$/yr)	M$ 1.2	M$ 4.8	M$ 6.9	M$ 4.7	M$ 2.0	M$ 6.3	M$ 1.7	M$ 7.1
ash / slag (MNLG/yr)					2.75	2.75	2.05	2.29
gypsum (MNLG/yr)					1.22	1.22		
sulphur (MNLG/yr)							-1.20	-1.34
total waste products (MNLG/yr)	0.00	0.00	0.00	0.00	3.96	3.96	0.85	0.95
total waste products (MUS$/yr)	0.00	0.00	0.00	0.00	1.86	1.86	0.40	0.45
Working capital								
15 days chemical storage (MNLG)	0.12	0.46	0.66	0.45	0.19	0.61	0.16	0.68
15 days chemical storage (MUS$)	M$ 0.1	M$ 0.2	M$ 0.3	M$ 0.2	M$ 0.1	M$ 0.3	M$ 0.1	M$ 0.3
Catalyst + internals (MNLG)			10.154					
Catalyst + internals (MUS$)			M$ 4.8					

EVALUATION OF ASSESSMENT CRITERIA
FOR
ASSESSMENT OF LEADING TECHNOLOGY OPTIONS
FOR ABATEMENT OF CO_2 EMISSIONS

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1. INTRODUCTION

This report is an addition to the 'Assessment of leading Technology Options of CO_2 emissions'. This report evaluates the criteria used in the assessment as specified by the IEA, technical study specification: GHG/98/40.

The assessment criteria are subject to change as technology develops and market insights vary. The intention of this document is to give an objective consideration of these criteria as they are experienced by the energy technology department of Stork Engineers & Contractors.

The criteria that need reconsideration are discussed in the following chapter. Only these criteria are mentioned, criteria that do not need reconsideration are left out.

2. EVALUATION OF CRITERIA

The following criteria need reconsideration:

LHV Gas
As discussed earlier the LHV of the natural gas specified in the assessment criteria is higher than 36.25 MJ/Nm3. Based on the molar specification of the gas the proper LHV becomes 46.899 MJ/kg.

Fuel Prices
The fuel prices used in the report are low. A higher fuel price would be more realistic. For natural gas 3 US$/GJ is suggested instead of 2 US$/GJ. For coal a price of 1.8 US$/GJ instead of 1.5 US$/GJ would be more appropriate.

Decommissioning cost
As pointed out in the study, the decommissioning cost are insignificant for the final results. Establishing the decommissioning cost is hard as it is, since you have to look 25 years ahead. But since the cash flow of the decommissioning cost occurs only after 25 years, the

effect after applying the discount ratio becomes negligible. Only in extreme cases such as nuclear power-plants these costs become significant.

State of the Art

The definition of state of the art is ambiguous; for the more complex power plants and for the CO_2 recovery plants there is no state of the art since plants of these types and at these scales do not exist. The techniques used definitely exist but not the integration of such complex techniques and at the size necessary for a 500 MWe power plant.

The developments in field of energy technology and abatement of CO_2 are not at such a high level that this requires a yearly study or even bi-yearly study. Since power plants of these types (with CO_2 capture) are not being actually built there is no development of the state of the art of the power plant as a whole.

CO_2 recovery method

After thorough discussion with our gas treatment department we concluded that there is no such thing as a elementary method to determine which type of CO_2 wash is to be used and how to use this for a technical study. For each case a comprehensive study has to be performed in order to establish a proper CO_2 wash method; only in this way the most efficient, and economically attractive method can be found.

Surely the added value of a conceptual study like this one is that experience allows process engineers to work without comprehensive studies. But the choice of solution and process for CO_2 wash from power plants can not be based on experience, since there is insignificant real life experience. Therefore Stork Engineering Consultancy suggests that in the future a serious study with aid from people experienced in gas treatment should be performed in order to select an CO_2 wash method for power plants that is state of the art.

Plant Size

The specification of a 500 MWe power plant at a high efficiency is not readily achievable by gas turbine based combined cycles. Gas turbines are designed and manufactured for a certain power production. The type of Gas Turbine determines the power production of the plant as a whole, and generally speaking the bigger the gas turbine, the higher the combined cycle efficiency. Generally such as in the case of a General Electric Frame 9 the power that can be achieved is in the range of 400 MWe. Therefore a more flexible specification would be desirable, such as a power plant in the range of 300-600 MWe.

Capital Charges and Cost of Debt

If the interest rate is to be equal to the discount rate then the expenditures for design and construction can be treated as a simple negative cash flow. Over the total lifetime of the plant the NPV of this calculation is equal to a calculation where yearly capital charges are used. Only when the interest rate differs from the discount rate there is a difference between the simple negative cash flows and using yearly capital charges.

For evaluation purposes of a range of power plants the exact method of how to handle capital expenditures is not that interesting. If however on the other hand a more detailed study is to be made than this is of great importance, but then also more specific figures need to be provided such as percentage of equity, taxation, depreciation etc.