IMPROVEMENT IN POWER GENERATION WITH POST-COMBUSTION CAPTURE OF CO_2

Report Number PH4/33
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Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) evaluates technologies for abatement of greenhouse gas emissions, with particular emphasis on capture and storage of CO_2 from use of fossil fuels. One of the leading technologies for capture of CO_2 from power generation is post-combustion solvent scrubbing. A study has been carried out to estimate the performance and costs of coal and natural gas fired power plants with and without post-combustion CO_2 capture. The study evaluates plants based on current technology and also predicts the performance and costs of plants that could be built in the year 2020. The study was carried out for IEA GHG by Fluor, in collaboration with Mitsui Babcock, Alstom and Imperial College London. The study is based on Fluor's Econamine FG+^{SM} CO_2 capture technology, which uses a mono-ethanolamine (MEA) based solvent. This process includes a split-flow configuration, an improved solvent formulation and better heat integration, resulting in significantly lower energy consumption than earlier MEA-based processes.

In parallel with Fluor's study, Mitsubishi Heavy Industries (MHI) carried out a separate study for IEA GHG to assess the performance and costs of their CO_2 capture technology, which is based on a hindered amine solvent called KS-1 and which has a lower energy consumption than MEA. Unlike Fluor's study, MHI's study was limited to only the CO_2 capture units and did not consider complete power plants. However, the two studies were carried out on a consistent basis, so IEA GHG was able to estimate overall plant performance and costs by combining MHI's information on the capture units and information on power plants from Fluor's study. This made it possible to compare the two proprietary CO_2 capture processes on a consistent basis. MHI's report was provided to IEA GHG under a confidentiality agreement. Members of IEA GHG who are interested in obtaining a copy of the report should contact IEA GHG and would be expected to sign a confidentiality agreement with MHI.

Study basis

The study was carried out using IEA GHG's standard assessment criteria. The main criteria are:

- Netherlands coastal plant location
- Australian bituminous coal
- Coal price $1.5/GJ, LHV basis (equivalent to $1.57/GJ HHV basis)
- Natural gas price $3/GJ, LHV basis (equivalent to $3.315/GJ HHV basis)
- 85% load factor
- 10% discount rate (constant money values)
- 25 year operating life

CO_2 capture significantly reduces the thermal efficiency of power generation. It is therefore important that a power cycle with a high thermal efficiency is used, to ensure that the efficiency is still acceptably high when CO_2 is captured. The current technology pulverised coal plants in this study are based on an ultra-supercritical steam cycle, with main steam conditions of 29 MPa, 600°C and a reheat temperature of 620°C. Plants with such steam conditions are commercially available.

The current technology combined cycle plants are based on the GE 9FA gas turbine, which is typical of the large gas turbines currently being produced by the main manufacturers. More advanced and efficient gas turbines such as the H class are being demonstrated but the first fully commercial H class power plant is not expected to commence operation until 2008. Plants based on H class turbines were assessed as a sensitivity case.

IEA GHG's standard assessment criteria state that all plants should, as far as possible, have the same net power output. In practice it is not possible to fix the net outputs of power plants based on gas turbines, because gas turbines are essentially fixed throughput machines. Any variations in ancillary power and steam consumptions affect the net power output. The combined cycle plants in this study are based on two gas turbines, in common with a recent IEA GHG study on CO_2 capture in Integrated Gasification Combined Cycle (IGCC) plants[1]. The net power output of the natural gas fired plant without capture in Fluor's study is about 750 MW and the net output of the plant with capture is about 670 MW. The net power outputs of the pulverised coal plants were set to be approximately the same as those of the corresponding natural gas fired plants. To achieve this, the plant with capture has a higher coal feed rate than the plant without capture.

Results and Discussion

Status of capture technology

Post-combustion MEA scrubbing has been demonstrated in commercial plants which produce CO_2, mainly for enhanced oil recovery, chemicals production and the food industry. Plants have been operated for over 20 years, with outputs of up to 1,000 t/d of CO_2. The plants in this study capture up to about 13,000 t/d of CO_2, so significant scale up is needed.

One of the main processes used in existing plants is Fluor's Econamine FG^{SM} process. The Econamine FG+^{SM} process, which is used as the basis for Fluor's study for IEA GHG, is a modification of the Econamine FG ^{SM} process. No commercial scale Econamine FG+^{SM} plants are currently operating but the process is being offered commercially by Fluor and a plant which will capture 375 t/d of CO_2 from reformer flue gas is being designed. MHI's study for IEA GHG is based on their KS-1 process. A KS-1 plant which captures about 200 t/d of CO_2 from reformer flue gas has been operating since 1999. Fluor and MHI's existing capture units are at gas fired plants. 150-200 t/d capture units based on the ABB Lummus Global/Kerr McGee MEA scrubbing process are operating at two coal fired power plants in the USA. Post-combustion CO_2 capture processes can be regarded as current technology but some demonstration of these technologies at large coal fired plants is needed before they can be widely adopted with an acceptable level of commercial risk.

The flue gas input to a solvent scrubbing unit has to have low concentrations of SO_X and NO_2, as these substances result in loss of solvent. The SO_X limit is set at 10ppm(v) by Fluor and 1ppm(v) by MHI. Such low concentrations can be achieved by current FGD technologies. The NO_2 limit set by Fluor is 20 ppm(v) but the selective catalytic reduction (SCR) unit included in the coal fired plants in this study produces a flue gas with a NO_2 concentration to 5 ppm(v).

Performance and costs of plants based on current technology

The performance and costs of plants from Fluor's study are summarised in table 1. The capital costs in table 1 exclude interest during construction, but this is taken into account in the calculation of the overall electricity generation costs. The costs of avoiding CO_2 emissions are calculated by comparing the same type of plant with and without capture.

The cost per tonne of CO_2 avoided is higher in the gas fired plant than the coal fired plant, mainly because the concentration of CO_2 in the flue gas is lower, so a greater volume of flue gas has to be processed. Despite this, the cost of capture in terms of c/kWh and the thermal efficiency penalty for capture are lower in the gas fired plant, mainly because less than half as much CO_2 has to be captured per kWh.

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[1] Potential for improvement in gasification combined cycle power generation with CO_2 capture, report PH4/19, May 2003.

Table 1: Cost and performance summary, Fluor current technology

	Pulverised coal			Natural gas combined cycle		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Plant performance						
Fuel input (MW, LHV)	1723	1913		1396	1396	
Gross power output (MW)	831	827		800	740	
Ancillary power consumption (MW)	73	161		24	78	
Net power output, MW	758	666		776	662	
Efficiency and emissions						
Thermal efficiency, % (LHV)	44.0	34.8	9.2	55.6	47.4	8.2
Increase in fuel use due to capture, %			26			17
Fuel for capture, kWh/t CO_2 avoided			0.96			0.99
CO_2 emissions, g/kWh	743	117		379	66	
CO_2 captured, g/kWh		822			378	
Costs						
Capital cost, $/kW net power	1222	1755	533	499	869	370
Electricity cost, c/kWh	4.39	6.24	1.85	3.13	4.40	1.27
Cost of CO_2 avoidance, $/t$CO_2$			29.5			40.7

Performance and cost data for plants based on MHI's capture technology are summarised in table 2. The coal fired plant without capture is slightly different to the Fluor plant, because it uses an MHI FGD unit.

Table 2: Cost and performance summary, MHI current technology

	Pulverised coal			Natural gas combined cycle		
	Without capture	With capture	Capture penalty	Without capture	With capture	Capture penalty
Plant performance						
Fuel input (MW, LHV)	1723	1913		1396	1396	
Gross power output (MW)	831	838		800	758	
Ancillary power consumption (MW)	77	162		24	66	
Net power output, MW	754	676		776	692	
Efficiency and emissions						
Thermal efficiency, % (LHV)	43.7	35.3	8.4	55.6	49.6	6.0
Increase in fuel use due to capture, %			24			12
Fuel for capture, kWh/t CO_2 avoided			0.83			0.69
CO_2 emissions, g/kWh	747	92		379	63	
CO_2 captured, g/kWh		832			362	
Costs						
Capital cost, $/kW	1171	1858	687	499	887	388
Electricity cost, c/kWh	4.28	6.30	2.02	3.13	4.29	1.18
Cost of CO_2 avoidance, $/t$CO_2$			30.9			37.2

The thermal efficiency penalties for CO_2 capture are lower for MHI's process as shown in figure 1.

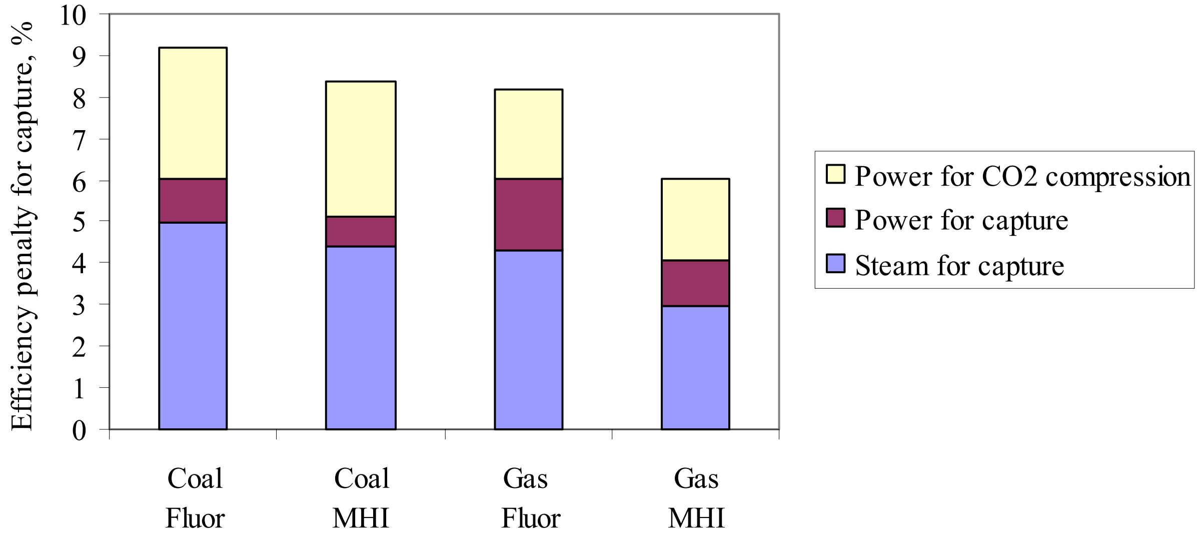

Figure 1: Thermal efficiency penalties for CO_2 capture

The CO_2 capture processes consume low pressure steam for solvent regeneration. This steam is extracted from the steam turbine, thereby reducing the net power output. The consumption of low pressure steam in Fluor's MEA scrubbing process (Econamine FG+^{SM}) is substantially lower than in conventional MEA scrubbing processes but the steam consumption in MHI's process is even lower because a hindered amine solvent is used rather than MEA. The steam consumption accounts for about half of the energy penalty for CO_2 capture and compression in all cases.

The power consumption of MHI's CO_2 capture unit is significantly lower than Fluor's, mainly because the flue gas fan power consumption is lower. This is probably due to the use of a structured packing with a low pressure drop, such as their KP-1 packing, in the absorber tower. Fluor's design is based on random tower packing but alternative packings could be used in principle. The power consumptions for CO_2 compression are similar in the MHI and Fluor processes, because they both produce CO_2 at close to atmospheric pressure and use similar types of compressor.

A breakdown of the capital costs of the plants with CO_2 capture is shown in figure 2.

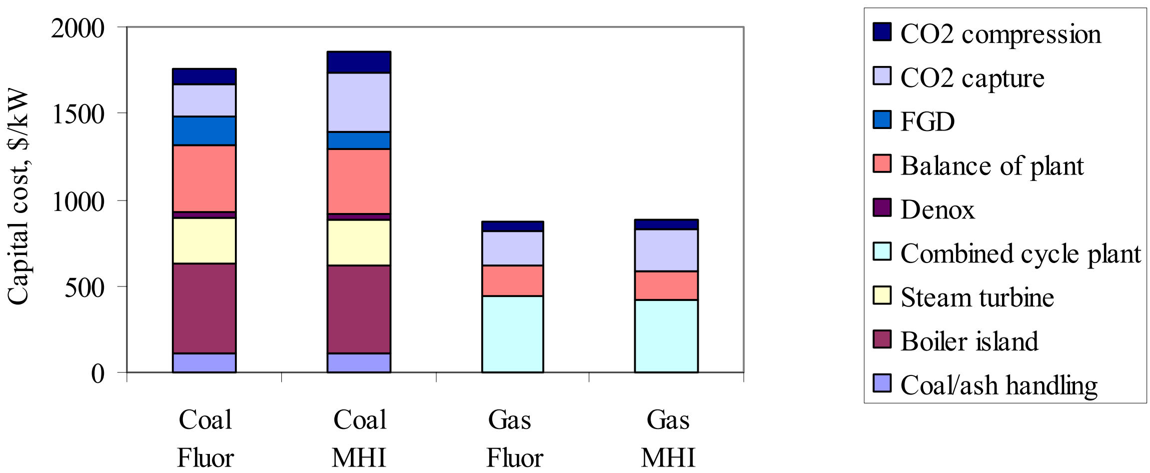

Figure 2: Power plant capital costs

The overall capital costs of the Fluor coal and gas fired plants are 5% and 2% lower respectively than the costs of the MHI plants. The costs of the power generation units (fuel handling, boiler, steam turbine, combined cycle plant, denox and balance of plant) are the same in $M for the Fluor and MHI plants, because they are based on the same source data. The costs in terms of $/kW are slightly lower for the MHI plants because the thermal efficiencies and net power outputs are higher. The cost of the FGD unit is lower in the MHI plant because it is based on MHI's technology. The capital cost of the capture unit in the Fluor gas fired plant is about 20% lower than that of the MHI plant, but this is within the limits of accuracy of the cost estimates. For the coal fired plants, the capture cost of the capture unit in Fluor's study is 45% lower than in MHI's study. Although there are some real differences in the plant designs, e.g. the degree of integration with the FGD, amine flow rates, types of column packing, quantities of heat transferred, etc., it appears unlikely that these differences would account for the magnitude, or even necessarily the direction, of the differences in the costs provided by the licensors. Cost estimating is not a precise science and there are inevitably differences between estimates prepared by different contractors, even when they are prepared on the same basis. The cost differences cannot be analysed further at present because the detailed dimensions and costs of the equipment in the capture units are commercially confidential.

The costs of electricity generation and CO_2 capture are broadly similar for Fluor and MHI capture technologies, as shown in tables 1 and 2. A breakdown of the cost of capture is shown in figure 3. This shows that the additional cost of fuel is a relatively small fraction of the total cost of capture. However, there are also capital and other operating and maintenance costs associated with producing the electricity and steam used for CO_2 capture and compression, and this are shown in the second block from the bottom on the bars in figure 3. The total costs associated with the energy consumptions account for 30-50% of the cost of capture.

The other major cost is the capital and O+M costs of the CO_2 capture and compression equipment. This is the part with the greatest uncertainty at present, because no capture plants of this size have yet been built. A significant part of the O+M cost is the cost of the chemicals consumed by the capture process, which is shown as a separate item in figure 3. Chemicals account for 8-14% of the total cost of capture in the Fluor plants and 5% in the MHI plants. The cost is lower in the MHI plants, even though the solvent is more expensive[2], because the solvent consumption is lower.

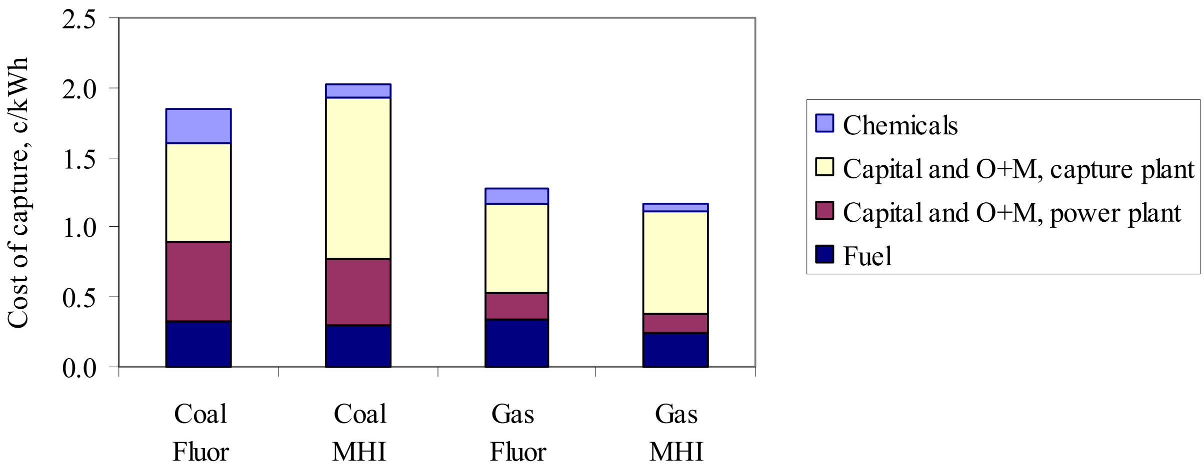

Figure 3 Breakdown of CO_2 capture costs

[2] In this study the cost of the KS-1 solvent used in the MHI process was assumed to be $4.5/kg, based on MHI's projection of the cost of large scale production, rather than current costs. The cost of Fluor's solvent (MEA + inhibitors) is $1.7/kg.

Cost sensitivities

CO_2 storage

The plants in this study include CO_2 compression to 11.0 MPa but transport and storage of CO_2 is not included. Costs of CO_2 storage depend greatly on local factors, such as the transport distance, the method of transport (pipeline or ship), the pipeline diameter and the type of storage reservoir. At some locations CO_2 could have a positive value for enhanced oil or gas recovery, which could result in a negative net cost of storage. As an illustration of the possible effects of CO_2 transport and storage on the overall cost of electricity, a cost of \$10/tonne of CO_2 stored would increase the cost of coal and gas fired electricity generation by 0.8 c/kWh and 0.4c/kWh respectively.

Fuel price

This study is based on coal and gas prices of \$1.5/GJ and \$3/GJ respectively (LHV basis). However, it is recognised that fuel prices are different in different locations and in many cases they fluctuate greatly over time. Sensitivities to fuel prices are therefore calculated and are shown in figure 4. This shows that the cost of generating power in a coal fired plant without capture, using coal at \$1.5/GJ, would be the same as that of a gas fired plant using gas at about \$5/GJ. Adding CO_2 capture increases the breakeven gas price slightly, to about \$5.5/GJ. The breakeven price would be slightly higher if the cost of CO_2 transport and storage was included, for example about \$6/GJ if the transport and storage cost was \$10/tonne of CO_2 stored.

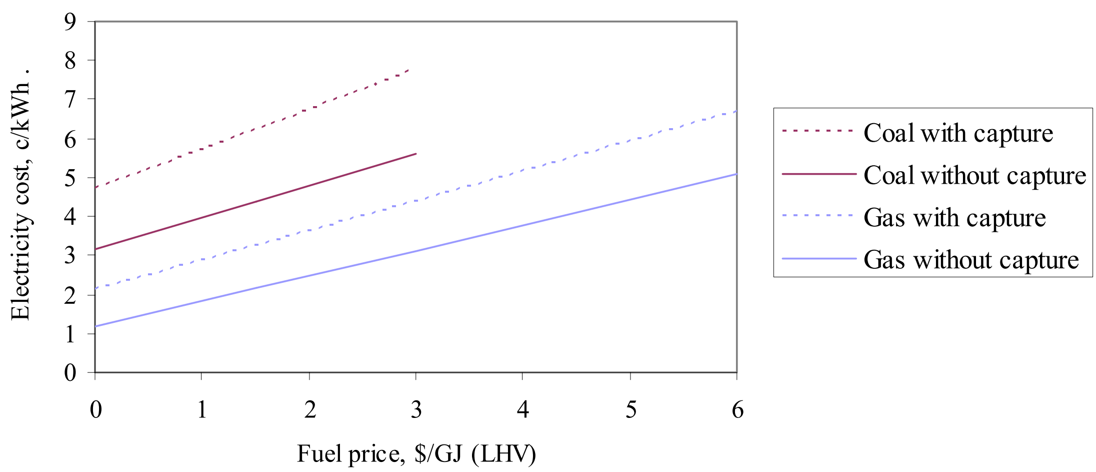

Figure 4 Sensitivity of electricity cost to fuel price

Other sensitivities

Sensitivities to discount rate, use of a 9H gas turbine, capture unit capital cost and stripping steam energy consumption are included in the main study report.

Technology stretch to 2020

Post-combustion solvent scrubbing processes are expected to improve between now and 2020. Improvements will be made by a combination of design optimisation in a competitive market and technology developments, such as new solvents. Combustion power generation processes are also expected to improve and these improvements will contribute to an overall improvement in the economics of power plants with post-combustion capture.

Fluor projects a 30% reduction in stripping steam consumption compared to their current technology and a reduction in the ancillary power consumptions due to lower pressure drops. MHI also expects energy consumptions to decrease. They have developed improved integration between the steam turbine and capture unit which can reduce the energy consumption by 4%. This could be applied now but was not included in the designs in this study. MHI is also carrying out R&D on solvents, with a target of reducing the steam consumption by 20%. The steam consumption of MHI's process is currently 12-30% lower than that of Fluor's process.

The overall capital cost of CO_2 capture and compression units in 2020 was projected by Fluor to be 60-70% of current cost. A breakdown of the cost improvements is given in the main report. A market for CO_2 capture plants would probably be necessary to fully achieve these improvements.

Because of the market pull which already exists for higher efficiency power plants, there is strong possibility of significant improvements in the efficiencies of power plants without CO_2 capture by 2020. The efficiencies of natural gas combined cycle and pulverised coal steam cycle plants without CO_2 capture are projected to increase by 6 and 5 percentage points respectively. Capital costs are also projected to decrease.

Fluor's projections of the performance and costs of power plants with CO_2 capture in 2020 are shown in table 3. The costs are based on current fuel prices.

Table 3: 2020 plant performance and costs

	Pulverised coal	Natural gas combined cycle
Efficiency, % (LHV)	40.2	55.4
Capital cost, $/kW	1240	602
Electricity cost, c/kWh	4.7	3.5
Cost penalty for capture, c/kWh	1.2	0.8
Cost of emissions avoidance, $/t CO_2	21	27

Research is currently being carried out on various novel post-combustion CO_2 separation technologies such as membranes and solid sorbents. If these developments are successful and the technologies become commercially established by 2020, they could further reduce the costs of CO_2 capture.

Expert Reviewers' Comments

Fluor's draft report was sent to expert reviewers for comment. The report was generally well received by those reviewers that responded. The most substantial comment was from MHI, who were sceptical about the capital costs of the CO_2 capture units in Fluor's study, particularly for the coal fired plant. This issue is discussed in this report summary. Other comments from reviewers were taken into account as far as possible in the final version of the report. MHI's report could not be sent to reviewers because of confidentiality.

Major Conclusions

The energy consumptions of the latest generation of CO_2 capture processes, as assessed in this study, are significantly lower than those of conventional MEA scrubbing processes.

Adding post-combustion CO_2 capture and compression would reduce the efficiency of a coal fired power plant by 8-9 percentage points and increase the cost of electricity by about 2 c/kWh, which corresponds to about $30/tonne of CO_2 emissions avoided.

Adding capture and compression would reduce the efficiency of a natural gas combined cycle plant by 6-8 percentage points and increase the cost of electricity by about 1.2 c/kWh. The cost of avoiding CO_2 emissions would be about $40/tonne.

Based on the information provided by the two process licensors, the energy penalty for CO_2 capture using MHI's KS-1 hindered amine solvent is 1-2 percentage points lower than that of the MEA-based Econamine FG+[SM] process offered by Fluor but the capital cost of MHI's process is higher, so the overall cost of capture is similar. However, capital cost estimates are subject to significant uncertainty and it is not clear whether the capital cost difference is due to real differences in plant costs or different estimating assumptions by the two licensors.

Improvements in power generation and post-combustion CO_2 capture technology between now and 2020 are expected to reduce the cost of electricity generation with CO_2 capture to about 4.7 c/kWh for coal fired generation and 3.5 c/kWh for gas fired generation. The costs of avoiding CO_2 emissions will be in the range of 20-30 \$/t CO_2.

Recommendations

IEA GHG should produce a summary of its recent studies on different CO_2 capture technologies.

Discussions should continue with process licensors to attempt to reduce the uncertainties in the capital costs of amine scrubbing plants.

IEA GHG should periodically up-date its assessments of the main CO_2 capture technologies for power generation.

Costs of post-combustion capture of CO_2 from other industrial flue gases should be estimated, to make it possible to produce regional and global cost curves for CO_2 capture and storage (the relationship between costs and the quantity of CO_2 captured and stored).

IMPROVEMENT IN POWER GENERATION WITH POST COMBUSTION CAPTURE OF CARBON DIOXIDE

FINAL REPORT

NOVEMBER 2004

Prepared by FLUOR for IEA GHG Programme

REPORT SECTION INDEX

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SECTION A

INTRODUCTION

1.0 Study Purpose

The International Energy Agency Greenhouse Gas R&D Programme (IEA GHG) was established in 1991 to evaluate technologies that could be used to avoid emissions of greenhouse gas created particularly from the use of fossil fuels. IEA GHG is an international organisation, supported by sixteen countries world-wide, the European Commission and several industrial organizations.

Emissions from fossil fuels could be reduced by capturing CO_2, particularly at large point sources such as power stations. The CO_2 would be injected into storage reservoirs, for example depleted oil and gas fields, deep saline aquifers, un-minable coal seams or the deep ocean. One of the options for capturing CO_2 involves separating the CO_2 from flue gases using solvent scrubbing, often referred to as post-combustion capture.

The aims of this study are to assess the performance and costs of post-combustion capture of CO_2 in power stations and the potential for improvements over the next 20 years. IEA GHG has retained Fluor to undertake this work which is described in this report.

IEA GHG has recently completed a similar study to assess the performance, costs and potential improvements for integrated gasification combined cycle power generation with and without CO_2 capture. The methodology for this study is broadly consistent with that use for the gasification study.

2.0 Study Workscope

One of the options for capturing carbon dioxide from the exhaust gas of power plants involves separating the CO_2 from the flue gas by solvent scrubbing, (often referred to as post combustion capture). It is proposed that the captured CO_2 would then be disposed of by injection into storage reservoirs such as depleted oil fields, gas fields, saline aquifers or un-minable coal seams.

A) The aims of this study are to assess the performance and costs of post combustion capture of carbon dioxide in power stations and the potential for improvement over the next 20 years.

The study work scope necessary to achieve these aims is described as follows:-

- **Identification of the main vendors of solvent scrubbing processes**
- **Summary of these technologies and their distinguishing features**
- **Assessment of commercial experience of each vendor**

- **Selection of a technology to be used in the assessments of power station post combustion capture**

These items are described and reported in Section D of this report. Their design basis development is described in Section C.

***B) Based on the chosen technology the following power station configurations have been assessed*:-**

- **A natural gas combined cycle plant without CO_2 capture**
- **A natural gas combined cycle plant with CO_2 capture**
- **A pulverized coal fired station without CO_2 capture**
- **A pulverized coal fired power station with CO_2 capture**

These four principal cases are described in detail in Section E of this report**.** Capital and operating cost estimates and economic comparisons are presented in Section F and Section G of this report respectively.

C) Additional cases have been formulated to examine cost sensitivities as follows:

- **Sensitivity to percentage recovery of carbon dioxide**
- **Sensitivity to carbon dioxide purity**
- **Sensitivity to gas turbine type in the NGCC cases (CASE 5 & 6)**

These sensitivity cases are presented in Section H of this report.

D) Potential technology stretch improvements in solvent scrubbing CO_2 capture between now and 2020 have been assessed and are presented in Sections J, K, L and M of this report

This assessment includes:

- Potential technology improvement possibilities (Section J)

- Estimates of performance and costs of power stations based on 2020 technology (Sections K and L)

- A roadmap for the introduction of these developments (Section M)

3.0 Acknowledgements

Fluor wishes to acknowledge the following persons and organizations for their particular support and work in the preparation of this study:

- Dr J Gibbins of Imperial College
- Mitsui Babcock for design work on the USCPF cases
- Alstom Power Ltd for design work on the steam turbine power islands
- Alstom Environmental Control Systems for advice and data on flue gas desulphurisation and ultra flue gas desulphurisation
- FLUOR’s US based technology team for the simulation of the EFG+ carbon dioxide capture process units.
- FLUOR’s Camberley based staff for the GTPRO simulations of the NGCC plants and supporting design and estimating work
- All of the above for contributions to the discussions around the 2020 power plant concept

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SECTION B

SUMMARY AND CONCLUSIONS

1.0 Foreword

The results presented in this study are for generic power plants which are not specific to a particular site or market situation. They are not optimised for market conditions which are characterised by a particular market price for generated power. The studies have only been used to calculate production costs on a levelised basis. Thus the calculated power generation costs represent the selling price necessary to pay for all the operating cost of the plants and to pay off the capital cost over the project life at a nominated discount rate (such that if the power were to be sold at the calculated cost, the NPV of the project would be zero).

The power generation costs should only be used, therefore, in making case comparisons within the study scope and these should not be compared with production costs from the real world which relate to particular market situations (which change from producer to producer).

The designs are, however, based on rigorous systems simulations made using industry accepted software and company specific proprietary design software. The results have then been used with existing, non-project specific capital cost data bases to estimate probable market prices for the power plants. It is important to note that these costs have not been estimated as part of a normal, project design programme even though they are believed to be realistic, competitive and representative of what could be achieved in the existing capital goods markets.

This report is based in part on information within the control of Fluor and its subcontractors. Whilst it is believed that the information contained herein will be reliable under the conditions and subject to the limitations set forth herein, Fluor cannot guarantee the accuracy thereof. The use of this report or any of the information contained therein shall be at the user's sole risk. Such use shall constitute an agreement to release, defend and indemnify Fluor and its subcontractors from and against any and all liability in connection therewith (including any liability for special, indirect, incidental or consequential damages) whether such arises in contract, negligence or otherwise.

2.0 Summary points

- The report presents a number of case studies of natural gas fired combined cycle and ultra supercritical pulverized fuel power plants with and without carbon dioxide capture and compression plants. The carbon dioxide capture plants have been properly integrated into the design of the power plants in an attempt to minimize the energy penalties associated with carbon dioxide capture. Plant capacities in the 800 MWe gross output range have been studied.

- The power plant technology employed is that which is currently commercially available in the market place.

- The carbon dioxide capture plant is based on solvent scrubbing of flue gas with amine solvents followed by steam stripping and recycle of the solvent and then drying and compression of the captured carbon dioxide. This is the only applicable technology for post combustion capture which is currently available at commercial scales. The technology is available from three suppliers. Two use MEA solvent and the third uses a proprietary amine (KS-1).

- Study of the processes shows that they all use the same basic flowsheet and all have been used commercially, albeit at nothing like the required scales for use in commercial power plants. Some demonstration of the technology is required at large scale on coal fired plants before it can be widely adopted with an acceptable commercial risk level. In this study it has been assumed that such demonstration would not reveal the need for any further pretreatment of flue gas than that which is currently used: viz: ESP, FGD and DENOX using SCR. The use of amine solvents requires a much higher FGD efficiency than is customarily achieved in the power industry. Levels of SO_2 need to be reduced to around 10 ppm @ 6%O_2 v/v, dry prior to the amine absorbers in the case of MEA use and this is a challenge for current designs of FGD process although there are new developments in the market place which can achieve this level; viz: Alstom Power's Flowpac Technology.. It has been assumed that 10 ppm is achievable without the need for further process development (It would be one of the issues requiring demonstration in a large scale demonstration unit.

- The amine scrubbing process can be operated with higher levels of sulphur dioxide but if higher levels of sulphur dioxide enter the amine absorber there is an increased loss of amine (as amine salts) from the reclaimer. The required level of 10ppm has generally been found to be optimal.

- Conversely, it is likely that application of these processes to gas turbine derived exhaust gas could be made at the required scale without the need for further demonstration. This is because natural gas fired turbine exhaust is free of the contaminants present in coal fired plant exhausts.

- Comparisons on a total life cost basis indicate that all of the amine based processes are roughly equivalent. This equivalence is achieved despite the lower stripping steam needs of KS1 solvent compared with MEA. New highly integrated and efficient flowsheet configurations used in the ECONAMINE + process for example offset this difference.

- FLUOR have selected EFG+ for this study because FLUOR has in house access to detailed simulation capability for it and because the EFG+ flowsheet features are well adapted to thermal integration of the unit with the power plant steam cycle (as discussed below). The study could have been done equally well with the MHI KS1 technology given the necessary capability in simulating its chemical kinetics and absorber behavior. Since all processes are roughly equivalent on a total cost basis this decision is not likely to have a significant effect on the calculated cost of electricity.

- This selection of EFG+ for this study basis does not imply a recommendation to use it although, obviously, Fluor would be happy with such use in any commercial applications.

- The report presents designs for power plants which are integrated with the carbon dioxide capture plant. The EFG+ process is already highly integrated within the confines of its battery limits and contains many flow sheet features which minimize steam consumption. However, it still requires the input of large quantities of low pressure steam which in these studies is extracted from the power plant steam turbines. This results in a loss of power output from the turbines since this extract steam is not available for expansion through the low pressure blading of the turbines. This power loss expressed as marginal fuel values (taking account of already high boiler and GT efficiency) represents the real cost of the stripping steam required. Many previous stand-alone CCS studies have allocated fictive import steam costs to evaluate the amine stripping but in this study this has not been done as it leads to overstatement of the true costs achieved in a truly integrated plant in which the only energy input is the fired fuel.

- This integrated approach shows that the “cost” of the stripping steam for amine regeneration in an integrated plant is perhaps not as significant as might have been thought. For example sensitivity calculations show that an as yet undiscovered solvent with a 50% lower stripping steam requirement than that of the base case (MEA solvent used in the EFG+ configuration) saves about 0.22 cents/kWh of generation cost. This is equivalent to a 2.3% gain in net cycle efficiency which is of course well worth having.

- This is based on constant capital expenditure from one sensitivity case point to another and takes no account of the likely high cost of such a solvent nor the changed mass transfer efficiencies and reaction kinetics which might pertain with its use (MEA by way of contrast is a cheap, bulk produced petrochemical commodity with good reactivity and mass transfer characteristics).

- These sensitivity simulations can be used to define stretch targets for amine developments. Thus, Fig B3 shows the effects of amine stripping energy improvement on gross power output in a NGCC integrated with amine capture.

- The thermodynamic principles used in formulating the integration concepts are described in the report. Broadly they consist of appropriate design taking account of both first law (achievable temperature differences) and second law (minimisation of exergy loss) together with appropriate use of pinch technology in the design of water preheat trains. Also, available chemical potential driving forces have been utilised in the use of a split flow amine absorber design in the EFG+ carbon dioxide capture plant.

- The results of the Case studies are shown on the following summary documents:

  Table B1 shows the gross and net outputs for the four cases comprising NGCC, NGCC with carbon dioxide capture, USCPF and USCPF plus carbon dioxide capture. Two further cases are shown for use of the GE 9H turbine concept.

  Table B2 summaries the capital cost estimate data for the cases.

  Fig B1 shows the cost of generation without carbon dioxide capture as a function of fuel cost for the two generation technologies.

  Fig B2 shows the cost of generation with carbon dioxide capture as a function of fuel cost for the two technologies.

- These graphs show very clearly that the generation price curves for natural gas combined cycle plants and ultra supercritical fired pulverized coal plants overlap. This means that there is a natural gas/coal price ratio at which the levelised costs of power are the same for both processes. Beyond this point USCPF becomes the cheaper option despite its much higher capital cost. Thus with a coal price of 1.5 US$/GJ USCPF is the cheapest generator when gas prices exceed 5US$/GJ. It is quite conceivable that these fuel price ratios will be attained and sustained in the medium term. Thus current US Government data (www.EIA.DOE.gov) shows a coal price projected to 1.3 US$/GJ with an equivalent market point gas price of 4.7US$/GJ. It is quite likely that gas prices will reach higher levels whilst coal prices are expected to remain fairly static. This has clear implications for the selection of appropriate generation technology for new plants especially now that USCPF is a high efficiency clean coal technology.

- The studies show that the efficiency loss caused by CO_2 capture is 8%-9%. This is expressed as a loss of efficiency points (**not** the percentage of lost output)

- Production cost sensitivity to changes in capital cost are as follows:

	BASE	**-20% Capex**	**+20% Capex**
NGCC/No capture	3.13	2.9	3.35
NGCC/With capture	4.4	4.01	4.8
USCPF/No capture	4.39	4.9	5.4
USCPF/With capture	6.23	6.4	7.5

- The data also show that use of the new GE 9H gas turbine and associated combined cycle HRSG and steam turbine combination gives a small scale and efficiency benefit. Use of this technology results in larger gross power outputs than is the case for 9FA turbines. The plant gross efficiency for the non capture case rises from 57.3% LHV to 59.9 % LHV but levelised COE remains around 3.1 cents/Kwh. The extra capacity is worth paying for as the specific capital costs (see Table B2) for the 9FA and 9H plants are approximately the same even though the total capital cost is a lot higher for the 9H case since it produces more power and gives a larger capacity plant at the same unit cost as the 9FA plant.

- The capital costs shown on Table B2 have been verified in the market place and represent realistic values. They have been benchmarked against actual contracts undertaken by Duke-Fluor Daniel (NGCC plants) and Mitsui Babcock (USCPF plants).

- Cost of avoidance of carbon dioxide emission is 40 US$ per tonne for the base case NGCC plant and 30 US$ per tonne for the USCPF power plant. Care is needed in the interpretation of these numbers since they can only be calculated with any commercial relevance in a particular commercial scenario. These numbers are calculated by comparing the case with capture to that without.

- The implication in the calculation of avoidance costs is that the reference plant is a true commercial base case. This is unlikely to be so since a commercial base case may be to not invest in power generation at all. There is in reality no carbon dioxide emission avoidance since all plants which are built will emit CO_2 in varying degrees whether mitigated or not. It does not make sense to quote an avoidance cost which is based on how much worse it might have been if something else (which is hypothetical) had been done.

- The true cost of capturing carbon dioxide is to be calculated by comparing costs of electricity generation with and without capture since kWh is the only market product. To date there is no basis for calculating a cost or value of captured carbon dioxide (until, that is, emission trading, emission capping and penalties for overstepping the caps are in vogue and it is then possible to establish a market price for avoided carbon dioxide emission).

- Because of the market pull which already exists for higher and higher efficiency, there is a very strong probability that unabated high efficiency power plants will be available by 2020.

- There are already many joint industry programmes with members acting out of strong self interest to develop better technologies which result in increased business for the equipment suppliers. For example, it is already clear that it is possible to build a clean USCPF plant in 2004 even though public perceptions are not yet aware of this (there is probably a case for action in public outreach to get this message home and to ensure that clean coal remains an option for power generation).

- The situation for carbon dioxide capture is very different since there is as yet no commercial driver for the development of the technology from its current base. It is very unlikely that developments will proceed without encouragement from government via the introduction of legislative programmes and the resulting carbon trading arrangements which force a commercial value onto CCS.

- Both of the commercially active technology owners have active programmes in place aimed at improving the performance of existing amines and finding new ones with the aim of lowering energy requirements, reducing corrosion and increasing carbon dioxide amine loadings. The future of the technology development is not however conditional on successful outcomes form this, nor from the development activities going on in various pure research organizations. Without these developments, the 2020 technology will merely result in higher operating costs and a higher capture cost.

- Given a "cost of carbon" which gave a commercial incentive, it would be possible to build a large scale carbon dioxide capture plant which could be integrated into a NGCC plant, using 2004 technology. This is not so in the case of USCPF plants because of the trace impurities in the flue gas, the removal of which requires demonstration before a very large capture plant could be designed with an acceptable commercial and technical risk level. So for the 2020 USCPF plant with capture to become a reality a fairly large demonstration is required. The absence of this constitutes a barrier which has to be surmounted (either by government/private possibly joint industry funding or development of an acceptable market price for captured CO_2) if a CO_2 mitigated 2020 USCPF plant is to be a commercial reality.

- Calculations of the cost of electricity production have been made for projected 2020 plants. The results (presented in US c/kWh) are summarised in Table L3 below:-

TABLE L3:-Summary of Cost Of Electricity from 2020 plants

	NGCC	NGCC+CO_2Capture	USCPF	USCPF+CO_2 Capture
COE 2004	**3.13**	**4.4**	**4.39**	**6.24**
COE(2020)	**2.68**	**3.47**	**3.54**	**4.7**
Delta	**0.45**	**0.93**	**1.54**	**1.54**
Reduction (%)	**14**	**21**	**19**	**25**

- This data shows that substantial reductions in the cost of electricity will result if the expected developments in the power plant and amine scrubbing technologies materialise by 2020.

- It is interesting to note that for both natural gas and coal fired plants, the cost of electricity **with** carbon dioxide capture in 2020 is roughly the same as costs of current technology **without** carbon dioxide capture; i.e. the expected improvements in technology will offset the expected cost of capture of carbon dioxide.

FIG B1 COST OF GENERATION VERSUS FUEL PRICE

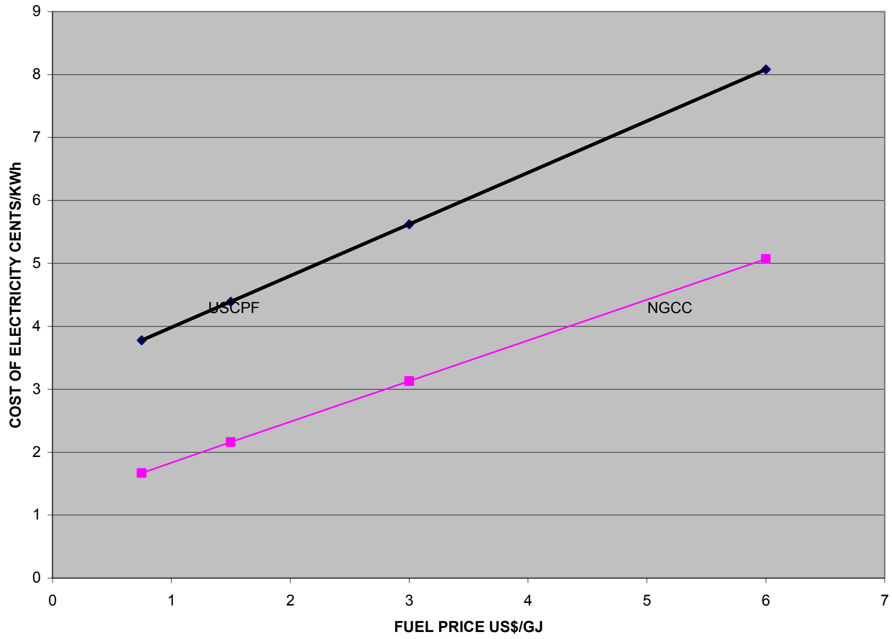

FIG B2 COST OF GENERATION WITH CAPTURE VERSUS FUEL PRICE

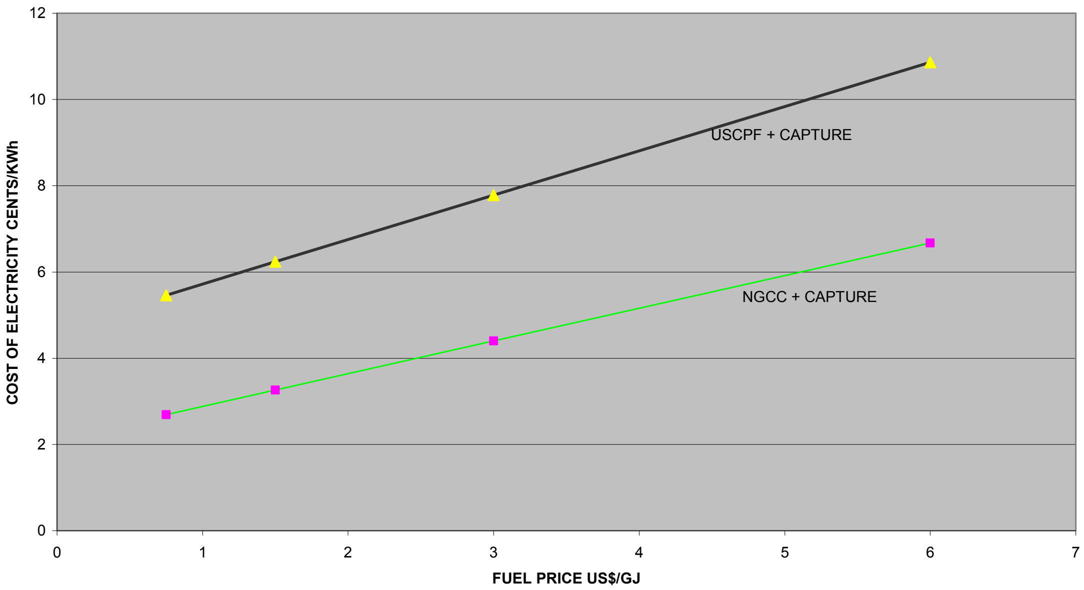

FIG B3 Gross Power output versus Stripping steam fraction

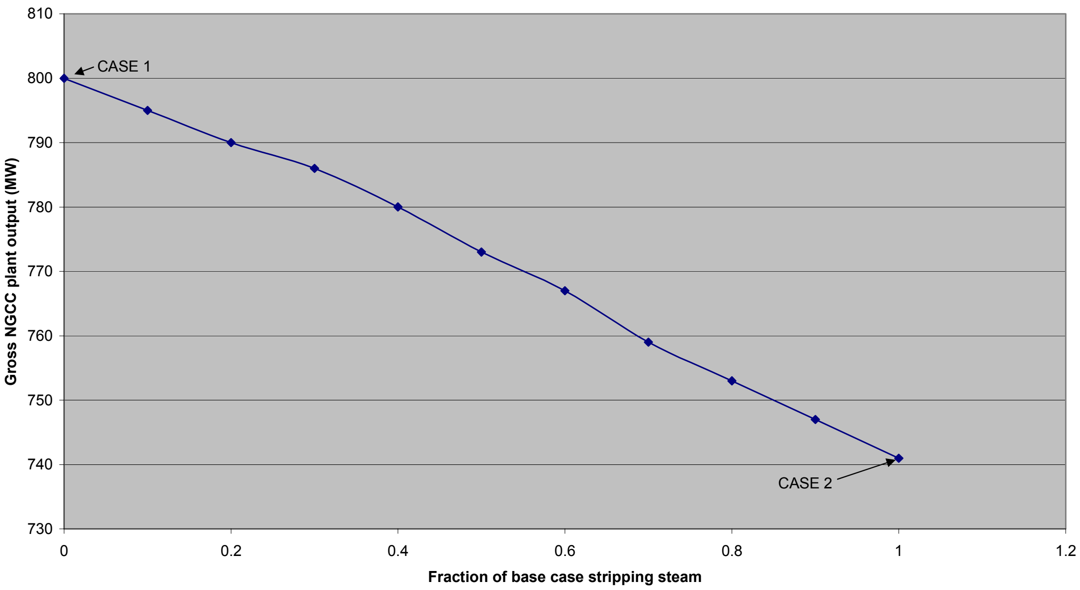

TABLE B1 CASE SUMMARY

	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6
	NGCC	NGCC+Capture	USCPF	USCPF+Capture	9h sensitivity	9h sensitivity plus capture
Fuel Fired	**1396**	**1396**	**1723**	**1913**	**1697**	**1697**
Gross Output	**800**	**740**	**831**	**827**	**1016**	**984**
Gross Efficiency	**57.31%**	**53.01%**	**48.23%**	**43.23%**	**59.87%**	**57.98%**
Losses						
FW Pumps	16	15	34	37	20	20
Draught Plant			8	9		
Coal mills etc			5	5		
ESP			2	2		
Misc			8	9		
Sub Total power plant	**16**	**15**	**57**	**62**	20	20
DCC Blower		20		14		22
Amine pumps		3		3		3
CO2 compression		30		60		36
Utility systems	8	10	10	15	10	13
FGD			6	7		
DENOX			0.3	0.4		
Sub Total Capture	**8**	**63**	**16**	**99**	30	74
Total Losses	**24**	**78**	**73**	**161**	30	94
Net Output	776	662	758	666	986	890
EFFICIENCY (Net power out/fuel in)	**55.59%**	**47.42%**	**43.98%**	**34.79%**	**58.10%**	**52.45%**
DELTA		8.17%		9.18%	APPROXIMATE ONLY see note 1	

NOTE 1 On this summary sheet the CASE 6 data has been manually adjusted for increased steam extraction with a downward reduction in net power (GTPRO sensitivity runs described in section H did not account for increased extraction required for the 9h case with its greater CO2 production)

TABLE B2 SUMMARY OF CAPITAL COSTS

CASE	NGCC	NGCC + CAPTURE	USCPF	USCPF+CAPTURE	NGCC FRAME 9H	NGCC FRAME 9H +CAPTURE
GROSS OUTPUT (MW)	800	740	831	827	1016	984
NET OUTPUT (MW)	776	662	758	666	986	890
PROJECT COST (MMUS$)	388	575	926	1168	504	767
COST (US$/Kw) GROSS	485	777	1114	1412	496	779
COST (US$/Kw) NET	500	869	1222	1754	511	862

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SECTION C

STUDY DESIGN BASIS

1.0 Configuration of power plants

This section gives an overview of the Case development, the chosen plant configuration and the basic engineering data used for the study basis.

1.1 Natural Gas Fired Combined Cycle Cases

The chosen configurations for the two NGCC cases are shown on Figs C1 and C2 below.

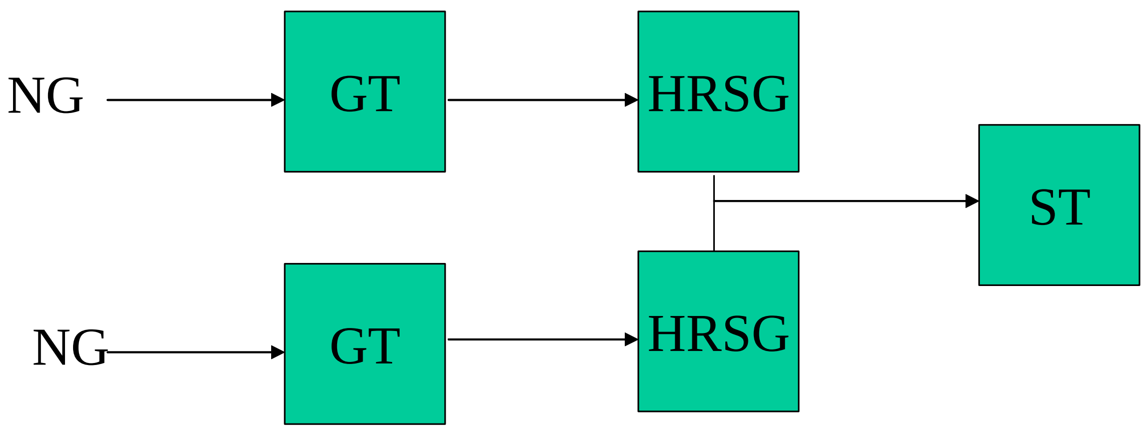


Fig C1 NGCC Without CO2 capture

The assessment (CASE 1) is based on current state-of-the-art design for this type of plant and is configured around 2 GE 9FA type gas turbines. Each turbine has an associated HRSG for steam generation followed by a single steam turbine generating system with a condensing last stage.

In the capture case, (CASE 2) the plant is closely integrated with an Econamine EFG + unit which captures the carbon dioxide. However, other proprietary processes are equally applicable; they all have the same basic flowsheet and differ only in terms of amine type and concentration. This is discussed in Section H and in Section D which describes the raison d'etre for selecting the EFG+ process for this study.

Fig C1 shows the two GE 9351 FA turbines each with a gross output of 260 MWe followed by two HRSG units and one steam turbine set with a gross output of 280MWe giving a total gross output of approx 800 MWe. These turbines are taken as representative of those available from a variety of manufactures and their use for assessment purposes does not constitute any recommendation to use them on a real project.

Fig C2: NGCC with CO2 Capture

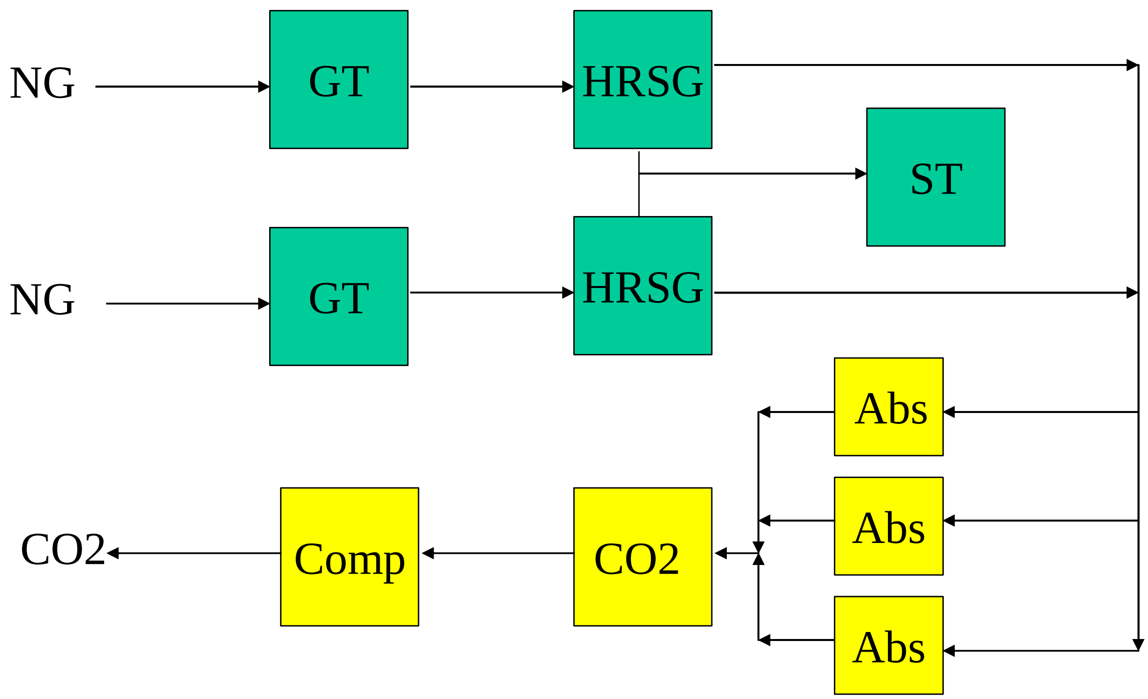


Fig C2 shows the same basic NGCC plant configuration with the addition of an Econamine EFG+ unit. This has three absorption trains with a single common CO_2 recovery and amine stripping stage followed by a carbon dioxide compression plant. The plant has been designed to be self sufficient in its energy balance so that the steam and power requirements of the capture plant are met by extraction of steam from the power cycle and by provision of power from the plants gross output. The extraction of the LP steam for the EFG+ plant causes a loss of output of 60 MWe (since the extract steam does not pass through the condensing turbine) so that the gross output in this capture case is 740 MWe.

The capture plant is designed to be closely integrated with the NGCC plant such that independent operation and retrofit options have not been considered. Viz: this means that the NGCC plus capture case is not the same as an NGCC case with a retrofitted capture plant. In fact, in going from the NGCC standalone case to the capture case, the thermal integration requirements dictate slightly different LP steam conditions and slightly different steam turbine configurations. This is described more fully below.

It should be noted that since the gas turbines operate with a dry low NOx staged combustion system, the anticipated NOx levels will be well below the limits required by the amine scrubber and this means that selective catalytic reduction for NOx abatement is not required in either CASE 1 or CASE 2. Similarly, since the natural gas fuel is very low in sulphur there is no need for any SOx abatement processes in the NGCC cases

1.2 Pulverised Coal Fired Cases

These cases (CASE 3 and CASE 4) are based on the use of a state-of-the-art Mitsui Babcock pulverized fuel fired ultra supercritical design. Again the choice of this technology for assessment purposes does not constitute a recommendation to buy.

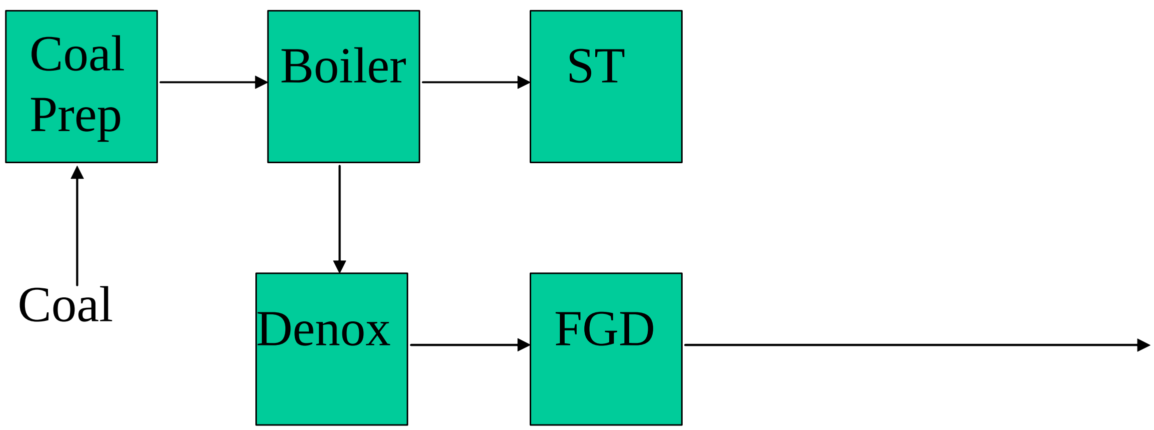


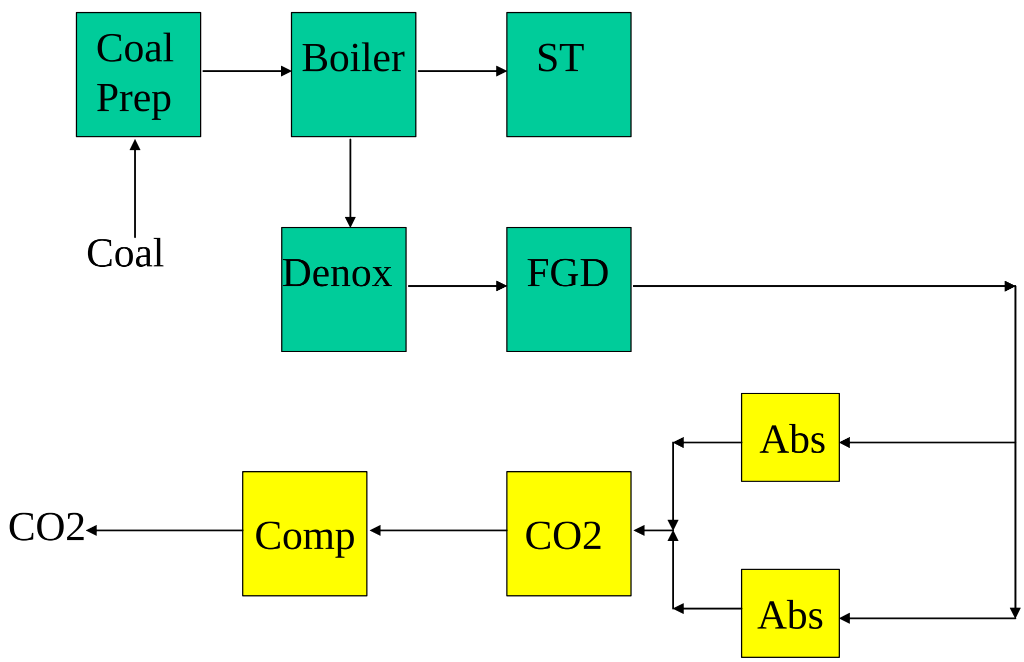
Fig C3: PF without CO2 Capture

In both cases the sulphur content of the coal requires the use of flue gas desulphurization with NOx reduction provided by selective catalytic reduction technology. The treatment requirements for the capture case are more severe than the non capture case since the amine based capture plant has stringent limits on the tolerable levels of NO_2 and SO_2 at the inlet. Excessive concentrations of these components cause high losses of amine as heat stable salts which are not regenerated in the stripping process and which have to be purged from the system.

The configurations of the cases are depicted on Figs C3 and C4. Fig C3 shows a single boiler and flue gas treatment train and Fig 4 shows a capture plant which in this case has two absorbers and a single amine stripping system. Fewer absorbers are needed than in the NGCC case since the volumetric flue gas flow from the boiler is much less.

As in CASE 2 the steam for the amine stripper in CASE 4 is extracted from the power cycle.

Fig C4: PF with CO2 Capture



1.3 Gross and Net Production Capacity of Cases

A summary of the case sizing basis is given on Table C1 below. The following procedure was used to establish the capacity of each case:

- **Case 1**:- Gross output is set by consideration of the maximum available power from two Frame 9FA GE gas turbines followed by steam turbine generation which maximises heat recovery from the gas turbine exhausts. The net power output (i.e. available for sale) is then calculated by subtracting the power consumption of the plant and the necessary balance of plant components.

- **Case 2:-** In this case two frame 9FA gas turbines are used and LP steam is extracted from the steam cycle at the required conditions for the carbon dioxide plant amine stripper reboiler. This means that less steam is available (than CASE 1) for expansion in the downstream steam turbines thus the gross power output for this Case 2 is about 60MWe less than that of CASE 1. The net power output is then calculated by subtracting the power plant auxiliary consumptions (as for CASE 1) plus the loads due to the carbon dioxide capture plant and the carbon dioxide compression plant.

- **Case 3:-** In this case the PF fired boiler was sized to provide the same net output as for CASE 1 after allowing for the estimated power consumptions of the auxiliary plants which in this case includes additional power demand from the FGD and DENOX plants (which are not required for the NGCC CASE 1 and 2)

- **Case 4:-** In this case a similar sized boiler to that used in CASE 3 was selected and incremental coal firing included sufficient to generate the additional energy needed to raise the LP steam required by the carbon dioxide capture plant. Thus CASES 3 and 4 have more or less similar gross power outputs. The gross power is then reduced to the net output by deducting the power consumptions of the auxiliary plants and the carbon dioxide capture and compression plants.

This methodology results in similar (but not identical) net power outputs for CASES 1 and 3 (776 and 758 MW respectively) and for CASES 2 and 4 (662 MW and 665 MW respectively).

This approach differs from that described in the IEA GHG study brief which asked for CASES 3 and 4 to have roughly the same net output as CASE 2 (the NGCC case with carbon dioxide capture). The suggested IEA GHG approach resulted in extensive iterations of design which proved difficult to coordinate effectively. The approach described above is believed to be satisfactory however since it results in four design cases which are all of roughly the same scale and which are therefore all comparable on a cost per kWh basis.

TABLE C1

SUMMARY OF CASE SIZING BASIS

GROSS AND NET POWER OUTPUT

	CASE 1	CASE 2	CASE 3	CASE 4
	NGCC	NGCC+CO_2	PF	PF+CO_2
GROSS MWe	**800**	**740**	**831**	**827**
Power Plant				
FW Pumps etc	16	15	34	37
Draught Plant			8	9
Coal/Ash/Mills			5	5
ESP			2	2
Misc. utilities			8	9
Subtotal MWe	**16**	**15**	**57**	**62**
CO_2 Capture				
DCC Blower		20		14
Pumps		3		3
CO_2 Comp		30		60
Utilities	8	10	10	15
FGD			6	7
DENOX			0.3	0.4
Subtotal MWe	**8**	**63**	**16**	**100**
TOTAL LOSS MWe	**24**	**78**	**73**	**162**
NET OUTPUT MWe	**776**	**662**	**758**	**665**

2.0 Process Integration

2.1 Integration Rules

Prior to finalizing the integration concepts, a study was made of a number of previously published reports as follows. All of these studies included various degrees of integration and some did not formulate integrated designs, usually because the design brief for the study precluded it. (Several of these studies were concerned with retrofits and deliberately limited the possibilities for integration:-

- EPRI-Parsons
- IEA Stork
- ABB Conesville
- Fluor/Transalta
- Waterloo/CANMET amine vs. oxyfuel study

Five principles were then established. Adherence to these principles should lead to the best possible thermal integration between the carbon dioxide capture plant and the power plant.

1. Add "source" heat at as high a temperature as possible so as to achieve the highest possible Carnot efficiency (set by source and sink temperatures). Add this heat to the highest efficiency combustion system and do not add auxiliary low efficiency combustion devices.

2. Reject heat to the "sink" at as low a temperature as possible

3. Extract as much work from the working fluids in the expansion turbines of the power train and only extract LP steam for amine reboilers at the lowest possible pressure and temperature.

4. Reject as little heat as possible to the sink and utilise as much waste heat as possible without violating any pinch rules.

5. Use the lowest possible energy in the amine stripper. This requires the use of the best solvents PLUS intensive integration within the amine capture plant.

Two additional constraints became apparent :-

A) Some theoretically sound integration ideas are not practicable because they require transfer of heat across a heat exchanger wall in situations where there is insufficient temperature difference for economic design. This issue arises in the design of the turbine vacuum condensers and the design of desuperheating plant and amine stripper reboilers.

B) Design of a so called "capture ready" plant could lead to different steam turbine choices to those that would be selected for a plant in which power plant and capture plant are co commissioned. In effect, the capture ready plant requires a retrofit of capture equipment which will then cause difficulties in the steam cycle because of the large extraction of LP steam for the amine stripper reboiler.

In this study, problem (B) is not addressed; ***the basis of design is that the capture plant would be built and commissioned at the same time as its respective host power plant. This means that CASE 2 for example is NOT the same as CASE 1 plus a capture plant. In fact they have different turbines and HRSG equipment.***

A corollary of this is that we have not studied cases in which the integrated power plant + capture plant are operated without the capture plant.

A third factor is also apparent when this problem is studied; viz: two plants, normally designed as stand alone entities and designed with high degrees in inside battery limit integration will show few good opportunities for thermal efficiency improvement when they are integrated.

2.2 Integration Design Development

The following paragraphs describe the integration design approaches. The exact parameters and design pressures and temperatures are shown on the flow sheets and mass balance tables in Section E and are not repeated here.

CASE 1 and CASE 2

In CASE 1 condensing conditions for the condenser were set by considering a reasonable approach to the sea water cooling temperature. From the condensation point an operating line was calculated to determine the inlet pressure to the IP turbine at the maximum temperature tolerated by the material of construction of the turbine. Inlet conditions to the high pressure (HP) turbine were chosen to meet the maximum tolerable turbine inlet temperature whilst the pressure was chosen to maximize the power output of the steam turbine.

The heat below the IP pinch is captured in the LP evaporator and superheater and admitted to the steam turbine at the crossover from IP to LP. The heat below the LP pinch is used to preheat boiler feed water. The pressure of the LP section follows normal steam turbine practice.

Since this case is a power cycle only the condenser can be used as the deaerator and any water required to make up for blowdown and system losses can be added to the condenser hotwell.

The fuel gas fed to the gas turbine is heated to 185 deg C with a water stream derived form the IP economizer. This ensures that the exhaust gas temperature is low and the heat thus recovered is utilized at maximum efficiency.

The quantity and composition of the gas turbine exhaust sets the size of the amine scrubbing system. In accordance with the integration rules, extra steam for the amine stripper reboiler is taken at the lowest possible pressure. This is determined by consideration of the required stripper bottom temperature which is set as low as possible to minimize degradation of amine but high enough to ensure adequate stripping. After allowing a practicable temperature difference allowance (to allow for a feasible reboiler design) the saturation temperature and hence the pressure of the extract steam can be set.

This pressure sets the crossover pressure between the IP and LP steam turbine and the pressure in the LP evaporator of the HRSG. For CASE 2, as the steam required by the amine plant is greater than the steam generated by the LP evaporator, there is no need to superheat the LP steam generated by the LP evaporator. The balance of steam required by the amine plant is extracted from the steam circuit and desuperheated with hot boiler feed water. As in Case 1, the heat in the gas turbine exhaust is used to preheat the boiler feed water and provides a final flue gas temperature to the amine unit of 101 degrees C. The heat and mass balance calculated using GTPRO shows a high degree of heat recovery as evidenced by the low flue gas temperature and there is little opportunity for introducing recovered heat from the amine unit.

Prior to the amine absorbers additional cooling is provided to produce an appropriate absorber inlet temperature. Treated flue gas is discharged to atmosphere from the top of the amine absorbers at 55 degrees C. Fluor experience on the Bellingham plant which operates in an area with severe winters, shows that discharge temperatures above 50 degrees C can be used and there are no problems with plume dispersion, thus no gas reheat is required.

CASE 3 and CASE 4

CASE 3 steam conditions have been selected at 290 bara and 600 degrees C with a single reheat to 620 degrees C. Using the same condensing conditions as for the gas turbine cases and working backwards along a proposed operating line to the maximum reheat temperature, provides pressures of 60 bara which becomes the design reheat pressure and IP turbine inlet pressure.

Bleeds of steam are drawn from the steam turbine to provide heat to the boiler feed water, reduce the condenser load and enhance the quantity of steam available at the turbine throttle. In CASE3 there are four banks of these preheaters. In CASE 4 an additional extract is taken from the IP turbines to provide the reboiler steam to the capture plant. Some of this steam is used as a final stage preheat prior to the deaerator. In this case three banks of steam heated preheaters are deleted along with their extract steam flows as these heating duties are made up by recovered heat from the capture plant. In the capture plant vacuum hotwell condensate is used to recover heat from the stripper overhead condenser and the carbon dioxide compressor intercoolers. This preheated condensate is returned to the power island downstream of the final preheat downstream of the deaerator.

Because the flue gas from the boiler is pre-cooled in the FGD plant, the cooling loads in the direct contact coolers are reduced.

3.0 Basic Data

This Section specifies the basic design data for the study and reiterates and modifies some of the IEA GHG data given in the document entitled Technical and Financial Assessment Criteria.

Location	NE coast of the Netherlands	
Currency:	US$	
Design and Construction Period	2.5 years NGCC cases / 3 years PF fired cases	
Plant Life:	25 years	
Load Factor	85% has been used for all technologies	
Cooling Water	inlet 12 degrees C: max rise 7 degrees C Sea water	
Emission Standards	particulates	25 mg/Nm^3 max
	NOx	200 mg/Nm^3 max
	SO_2	200 mg/Nm^3 max
CO_2 Recovery	85%	
Site Conditions	Ambient air	9 deg C
	Relative humidity	60%
	Atmos pressure	1.013 bara

Natural gas Fuel	C1	83.9 mol%
	C2	9.2
	C3	3.3
	C4+	1.4
	CO2	1.8
	N2	0.4
	H2S	4 mg/Nm^3
	LHV	As calculated by GTPRO

Coal specification

Proximate analysis	coal dry and ash free	78.3%
	Ash	12.2 %
	Moisture	9.5%
Ultimate analysis	carbon	82.5%
	Hydrogen	5.6
	Oxygen	9.0
	Nitrogen	1.8
	Sulphur	1.1
	Chlorine	0.03
LHV	25.87 MJ/Kg	

Carbon dioxide specifications:

These have been set by review of Kinder Morgan pipeline transport specification requirements as used by FLUOR in the CCPP studies:-

CO_2	95% Minimum (To achieve satisfactory MMP for EOR)
N2	4% max (ditto)
Hydrocarbons	5% (ditto)
H2O	-40 dewpoint (to minimize corrosion)
Oxygen	100 ppm (ditto)
SOx	approx zero
NOx	report
H2S	less than 25ppm to avoid sour service pipeline designation

In practice these specifications are exceeded by the EFG+ process.

Simulation Tools: GTPRO, Aspen Plus and specialized in-house software

4.0 Economic Assessment Criteria

These are described in Section G Economic Comparisons.

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SECTION D

SELECTION OF SOLVENT SCRUBBING TECHNOLOGY

1.0 Summary

This report provides a summary of existing amine scrubbing technologies which are under consideration for the expected market in post combustion carbon dioxide capture from power plant exhausts. Comparisons are presented of MEA and KS-1 solvent based processes and it is shown that the technologies are more or less equivalent in terms of costs and flow sheet configurations. Thus ***it is unlikely that technology choice will have much effect on amine solvent post combustion capture costs*** which are high and will remain so unless there is a breakthrough made by the introduction of a cheaper technology; there are none in view although there are candidates in an early sate of development.

For this reason ***this study is based on use of the FLUOR Econamine Plus SM technology***, primarily because FLUOR as authors of this study have complete and detailed information on the design of this process and the requirements for its integration into a power cycle. ***This should not be construed as a recommendation for the use this process.***

2.0 Technology Availability

CO_2 capture technology is used today to supply the merchant market for CO_2 and for removing CO_2 from hydrocarbon gas streams in the oil and gas production business. There is as yet no commercial market for its use in post combustion carbon dioxide from power plants. Technologies for this burgeoning market, are under development as follows:-

- New developments of existing absorption processes which use chemical and physical solvents
- Adsorption using pressure swing and temperature swing techniques
- Membrane processes
- Cryogenic processing

It is highly probable that because of the advanced state of development of amine based absorption processes they will be the first to be used in power plant post combustion capture plants. In fact, to date, nearly all commercial CO_2 capture plants use processes based on chemical absorption, with an alkanolamine solvent.

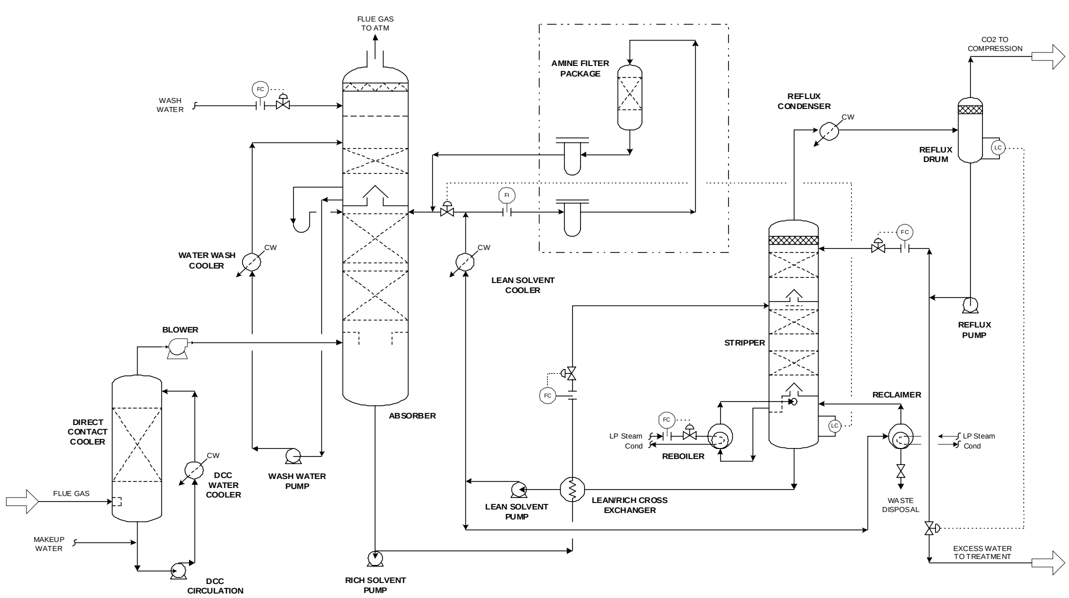
MEA is widely used and processes using it were developed over 60 years ago for general, non-selective removal of acid gases, such as CO_2 and H_2S, from natural gas streams which are generally oxygen free. The process was modified to incorporate inhibitors to resist solvent degradation and equipment corrosion when applied to CO_2 capture from flue gas in which oxygen is present. These modified processes were developed to meet the needs of the merchant CO_2 market and latterly, at a much larger scale, for the production of CO_2 for enhanced oil recovery

(EOR). The solvent strength was kept relatively low, resulting in large equipment sizes and high regeneration energy requirements.

A typical example of an amine scrubbing unit is shown on Figure D1 (this is a flowsheet of Fluor's Econamine FG SM process). Typically, the process allows flue gas to be quenched prior to contact with an MEA solution in an absorber. The MEA selectively absorbs the CO_2 and is then sent to a stripper in which the CO_2-rich MEA solution is heated to release almost pure CO_2. The lean MEA solution is then recycled to the absorber. Commercially available processes contain additional features to achieve a high degree of thermal integration within the process in order to minimise the stripping heat load. One of the commercially available processes (MHI) uses KS-1 sterically hindered amine (discussed below) but has similar flowsheet features to the MEA processes. In terms of flowsheet definition and operational principles all of the commercially available amine scrubbing processes are more or less the same. The absorber/stripper configuration described is very much "open art" and such systems could apparently be designed and built by anyone with the necessary process engineering skills.

However, whilst in theory there are any number of chemical engineering contracting companies who could do this, there are in practice very few who would be prepared or able to offer technology which has been adapted and proven for use in oxygen containing flue gas streams.

Figure D1 Typical Flowsheet of an Amine Scrubbing Process



There is in fact a considerable know how element necessary to design and operate such an amine unit with an acceptable, defined degree of technical (and therefore commercial) risk. The principal companies who fall into this classification and who offer licensed technology (largely protected by Patents and not therefore strictly open art) are: -

- **Fluor**:-Fluor offers the Econamine FG Plus SM process. This is a development of the MEA based ECONAMINE process developed by Dow and acquired by Fluor.

- **MHI**:- Mitsubishi Heavy Industries offers the KS-1 process which is a joint development between MHI and the Kansai Electric Power Company (KEPCO).

- **ABB**:- ABB Lummus Global offers MEA scrubbing technology based on the original Kerr Mc Gee process.

3.0 Commercial Amine Scrubbing Technologies

Table D 1 is a summary of commercial plants based on these three companies processes, (see Tables D2, D3 and D4 for further details on these plants categorised by technology provider) categorised by capacity ranges and end use of the carbon dioxide. It thus defines the limits of what is commercially available in the market place. In this sense "commercially available" means that a plant could be purchased, built and operated without any need for further development or scale up using feedstocks that have been demonstrated at the required scale. It should be noted that there are probably many more small scale open art process plants in operation than shown on this list, notably in the food industry.

Conclusions from this summary are that:

- There are few plants built on large scale commercial power generation plants and they are of small capacity relative to that required for normal large scale power plants.

- There is a large number of small capacity plants (mostly for producing carbonation gas for use in beverages).

- Plants up to 1000 tons per day capacity have been built for the chemicals industry and for production of CO_2 for enhanced oil recovery (EOR) using a variety of feed CO_2 sources.

It is clear that some commercial development is required to extend the envelope of current commercial availability into the region required by prospective large scale CO_2 removal from power plant exhausts.

TABLE D 1

COMMERCIAL PLANTS SUMMARY
(See Tables D2, D3, D4 for details)

CO_2 END USE	**MAX CAPACITY TPD**	**NUMBER BUILT**	**FEED SOURCE**
EOR	1000	3	NG
FOOD/BEVERAGES	300	More than 20	NG
CHEMICALS	800	5	NG/COAL

TABLE D 2

FLUOR ECONAMINE FG^{SM} - COMMERCIAL PLANTS

OWNER	LOCATION	SIZE, Tonne/day	Plant Purpose
Plants no Longer in Operation			
N-Ren Southwest	Carlsbad, New Mexico	90	Enhanced Oil Recy
Carbon Dioxide Tech. Corp.	Lubbock, Texas	1000	Enhanced Oil Recy
*Paca	Israel	25	Food Industry
Plants in Operation			
Liquid Air Australia	Altona, Australia	60	Food Industry
Liquid Air Australia	Botany, Australia	60	Food Industry
*Industrial de Gaseoses Cia. Ltda.	Quito, Ecuador	6.0	Food Industry
*Pepsi Cola	Manila, Philippines	6.0	Food Industry
*Pepsi Cola	Quezon City, Philippines	6.0	Food Industry
*Cosmos Bottling Co.	San Fernando, Philippines	6.0	Food Industry
*San Miguel Corp.	San Fernando, Philippines	40	Food Industry
Indo Gulf Fertilizer Co.	Uttar Pradesh, India	150 ++	Urea Plant Feed
Luzhou Natural Gas	Sechuan Province, PRC	160 ++	Urea Plant Feed
Northeast Energy Associates	Bellingham, Mass.	320	Food Industry
Kansei Electric Power Co.	Osaka, Japan	2.0	Pilot Plant
Tokyo Electric Power Co.	Yokosuka, Japan	5.0	Pilot Plant
Sumitomo Chem/Nippon Oxygen	Chiba, Japan	150 ++	Food Industry
*Cervezaria Baveria	Barranquilla, Colombia	25	Food Industry
Prosint	Rio de Janeiro, Brazil	90 (2 Units) ++	Food Industry

TABLE D 2 (continued)

OWNER	LOCATION	SIZE, Tonne/day	Plant Purpose
*Coca Cola	Cairo, Egypt	6.0	Food Industry
*Azucar Liquida SA	Santo Domingo, Dom. Rep.	6.0	Food Industry
# European Drinks	Sudrigiu, Bihor County, Romania	36	Food Industry
* Messer Greisheim do Brazil Ltda	Sao Paulo, Brazil	50	Food Industry
# Messer Greisheim do Brazil/SPAL	Sao Paulo, Brazil	80	Food Industry
# Grupo Walter	Barcelona, Spain	67	Food Industry
# Air Products	Singapore	36	Food Industry

Skid-mounted plants built by Union Engineering A/S
*Skid-mounted plants built by Wittemann (Wittcold)
All capacities listed are in metric tons

++ Operating on Steam Reformer Flue Gas

TABLE D 3

MHI KS-1 PLANTS

OWNER	LOCATION	SIZE, Tonne/day	Plant Purpose
Nanko Power Plant	Osaka, Japan	2.0	Pilot Plant
Petronas	KedahDarul Aman Malaysia	210 max	Urea

These plants operate with KS-1 amine formulation

TABLE D 4

Kerr McGee/ABB Lummus Global PLANTS

OWNER	LOCATION	SIZE, Tonne/day	Plant Purpose
North American Chemical Co	Trona CA	800	Soda Ash
Soda Ash Botswana	Sua Pan	300	Soda Ash
Applied Energy Systems	Poteau,OK	200	PURPA Food Grade
AES	Warrior Run	150	Food Grade

Note: All of these plants operate on coal derived flue gas

4.0 Commercial Developments for Power Plants

Absorption based amine scrubbing processes are the only technologies available in the market place at anything approaching the scale required for post combustion CO_2 capture from power plants. They are well suited to this with some process modifications, needed to overcome the particular problems posed. However, the suggested modifications have yet to be demonstrated in existing commercial plants even though there are many paper studies which demonstrate their feasibility.

4.1 High oxygen concentrations:

Most single component amine systems cannot operate in a flue gas environment, because the amine will rapidly degrade in the presence of oxygen (ref D1). For example the Fluor Econamine FG^{SM} technology uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 from low pressure, oxygen-containing flue gas. This formulation includes a proprietary inhibitor which also protects the equipment against corrosion and allows for conventional materials of construction, mostly carbon steel. Other processes use sterically hindered amine formulations (viz: MHI KS-1 solvent). This aspect of the technology is undergoing development all the time and new classes of amines can be expected in the future.

Figure D2: Saudi Aramco Econamine (DGA) Plant in Uthamaniyah, Saudi Arabia – The absorber (center-right) has a 40-foot diameter

4.2 ***Scale up***

Post combustion capture from power plants requires the use of very large equipment because of the enormous exhaust gas volumes produced. Thus there is a scale up issue associated with the prospective use of these processes. This scale up issue has been addressed in other applications of amine scrubbing technology and is not anticipated to be a problem. With absorber diameters of 40 to 50 feet considered feasible (Figure D2 by way of an example), CO_2 recovery plant capacities of up to 8,000 Te/d are achievable, depending on the inlet flue gas CO_2 concentration. Even larger plants can be realized by employing multiple absorbers that share a common stripper.

4.3 ***Energy Consumption***

The recovery of carbon dioxide from the rich amine stream from the absorber is a highly energy intensive procedure which requires substantial quantities of low pressure steam extraction from the power plant turbine cycle and high power usage for compressing large volumes of flue gas to overcome absorber pressure loss. This results in a significant energy loss. On small plants for the merchant market this is of little consequence but at the large scale of post combustion power plant capture it is serious. Technology developers have therefore concentrated on developing new generations of technology which minimise this steam consumption, by ensuring that a high degree of thermal integration is achieved in the process and/or using amines with lower stripping steam requirements either with improved formulations (Fluor) or improved amines (MHI with their KS-1, 2 and 3 series of amines which have a much lower specific stripping heat requirement than MEA). For example, using the Econamine FG^{SM} technology and experience as a starting point, Fluor has developed an improved process called Econamine FG Plus^{SM}. The new technology targets a goal of further lowering the energy consumption of the process. The Econamine FG Plus^{SM} process is now being offered with improved solvent formulation, split flow configuration, partial stripping with stripper reboiler condensate flash steam and absorber Intercooling. Further integration with the power plant cycle and carbon dioxide compression system is also possible.

4.4 ***SO_2 and NOx in Flue Gas***

Since amines are moderate bases, they will react with any acidic compounds to form amine salts. Usually these amine salts will be heat stable and will not dissociate in the amine stripping system. For this reason it is necessary, on economic grounds for all processes, to restrict flue gas SO_2 and NO_2 to low levels (typically 10ppmv @ 6% O_2 and 20ppmv @ 6% O_2 respectively). This creates additional processing requirements on the power plant gas treatment system, particularly in coal fired plants and this adds substantial costs to the CO_2 removal.

The removal of SO_2 down to 10ppmv via existing FGD technology is a technical challenge since such low levels are not currently required. It can be achieved in existing plants by retrofit to existing wet scrubbing systems (an additional scrubbing stage) or by adding an additional scrubbing and gas conditioning stage into which an alkali can be introduced to mop up the SO_2. This results in additional effluent discharge however. In the case of new plants, wet limestone scrubbing technology is available which can achieve 10ppm without any significant increase in costs compared to current installed technologies. For example, a description is given in [Ref D8] of Alstom Power's new process (FLOWPAC) which has achieved 10ppm sulphur dioxide concentrations in flue gases derived from fuels with 2 to 3.5%w/w sulphur.

In the case of NO_2 reduction, low NO_x burner technology helps to reduce NO_x to much lower levels than would otherwise be the case and then SCR can be used to achieve the required low NO_2 levels.

Other Impurities

There are a number of unknowns concerning the effect on amine systems of other types of impurity which may be present in coal fired plant flue gas. Theoretical development studies are addressing these issues via a number of current studies, but it is probable that some type of pilot operation will be required prior to the large scale adoption of amine scrubbing on commercial plants. This is despite the fact that technical solutions for the removal of all of these impurities can be found in the current technology market. Most commercial businesses will in fact require demonstration of new technology, or even new combinations of existing technologies, before they will adopt it at large scale. This is in order to demonstrate that the commercial risks are acceptable prior to the construction of a new plant.

5.0 **Comparison of Amine Scrubbing Technologies**

5.1 Economic Comparison

MHI has published papers on the performance of its KS-1 solvent in the Petronas Fertilizer Co. CO_2 capture plant in Malaysia (Ref D2). This is the only commercial installation of KS-1. Using this data, the performance of MEA based technology can be compared to KS-1.

The flue gas conditions are listed in Table D5. The gas source is a steam reformer.

Table D5: Petronas Fertilizer Co. Reformer Flue Gas Conditions

Flow Rate	47,000 Nm^3/h
Temperature	168 °C
Composition	
N_2	67.79 % (v/v)
CO_2	8.08 % (v/v)
O_2	0.85 % (v/v)
Ar	1.00 % (v/v)
H_2O	22.28 % (v/v)
SO_X	2.44 ppm
NO_X	200 ppm

The plant recovers 90% of the carbon dioxide for a total product rate of 160 Te/d. The product has a dry purity of over 99.9 vol% CO_2 and its pressure is 0.55 barg.

Table D6 shows the energy consumption and amine cost for the two processes. The Econamine FG Plus SM process has been used as a typical comparison (Ref D6) for an MEA process since it uses higher MEA concentrations than the Kerr McGee technology and this will result in lower energy demands. Thus the Econamine EFG Plus^{SM} process should be expected to show the best that can currently be achieved with MEA.

Table D6: Comparison of Econamine FG Plus^{SM} and KS-1 (Ref D6)

	Units	Econamine FG Plus^{SM}	KS-1
Energy Consumption	Btu/lb CO_2	1395	1376
Solvent Replacement Cost	US$/Te CO_2	2.30	2.28

As seen in the table, the Econamine FG Plus^{SM} technology requires less than 1.5% more energy that MHI's KS-1 solvent. This is a considerable improvement over the original Econamine FG Plus^{SM} process energy requirement. This comparison shows that the operating cost differences between the technologies are marginal and that they are roughly equivalent. In fact the disadvantage (high stripping steam requirement) of MEA compared with KS1 has been overcome by means of flow sheet development and optimisation which incorporates a very high degree of thermal integration.

In terms of capital cost the three commercial amine scrubbing technologies show some differences (Ref D7) but these are marginal and are probably due to the different engineering embodiments employed in the reference study. However it is probable that the Econamine EFG Plus^{SM} process is the cheapest by small margin because it uses low cost standard mass transfer packing and operates with a high amine concentration which gives some reductions in equipment sizes (by comparison with other MEA based processes). This opinion could only be verified by detailed design comparisons on a carefully defined, common basis; no such study has ever been published in the public domain.

For both types of process (MEA and KS-1) the solvent replacement costs are nearly identical. This is because although the KS-1 solvent loss is reported to be less than that for Econamine FG Plus^{SM}, the cost of KS-1 is 4.3 times more expensive than Econamine FG Plus^{SM} solvent (MEA plus inhibitor). (Ref D4)

The conclusion of this economic comparison is that all commercial amine scrubbing processes are roughly equivalent.

5.2 Multi factorial comparison

Table D7 shows a multifactorial comparison of the three available amine scrubbing technologies. Explanatory notes for this table are as follows:

Note 1:- All of the processes will require pretreatment of raw flue gas, particularly those derived form coal fired plant since these are likely to contain, in particular, high levels of SO_2 and NO_2 which will be neutralised by the amine to form heat stable salts. MEA processes usually have a solvent reclaiming system to assist in solvent recovery but any heat stable salts have to be purged form the system and constitute loss.

Note 2:- There are many examples in the chemical and petroleum refinery industries where there are larger equipment sizes than those which will be needed in commercial power plant post combustion scrubbing units. There are also cases where the scale up factors in going from one generation of plant to the next have been larger than those anticipated in post combustion amine scrubbing commercialisation. Scale up is not therefore seen as a potential problem.

Note 3:- Energy use has been substantially reduced in the latest evolution of MEA scrubbing plants such that they are now competitive with KS-1 which remains the gold standard for low energy consumption. Development work continues with MHI developing KS-2 and KS-3 amines which are expected to have lower consumptions than KS-1 (as low as 670 kgcal/kg of CO_2). FLUOR are also developing new alkanolamine systems, based on MEA which are expected to lower the energy consumption of the EFG + process still further. It is not yet known what the asymptotic limits will be for further generations of technology. If a commercial market develops for post combustion removal processes, then there will be an intensification of research in the area of new and improved amine formulations from all technology developers and suppliers.

Note 4:- The FLUOR EFG+ plus process probably has the lowest capital cost. However caution is required in interpreting this statement since detailed comparisons are required to establish this. There are no published studies which report comparisons (of all three processes in the same study) done with estimates of the required accuracy and based on installation at a specific highly defined site. Published study work done to date has not produced sufficient detailed design and estimating data to allow this question to be answered.

Notes 5 & 6:- All amine scrubbing processes when applied to post combustion carbon dioxide recovery have high operating costs. The principal elements are capital charges and energy costs. MEA processes have an advantage in that the amines they use are cheap commodity chemicals whereas KS-1 solvent is a speciality formulation of high cost and limited availability. It is unlikely that amine scrubbing costs will achieve dramatic reductions (they already represent mature technology).

Notes 7 & 8:- There is limited operating experience with the MHI KS-1 process. The single commercial plant operates on a stream with very low oxygen concentrations (0.87%) and there are, therefore, outstanding questions on the long term stability of KS-1 solvent operating in a commercial environment with oxygen concentrations of 4-12% which is the probable range of power plant flue gas. FLUOR has the greatest amount of commercial experience and has long term operational experience of plant on gas turbine exhausts. The Kerr McGee MEA process is the only one of the three processes which has operated on plants with coal derived flue gases although both MHI and FLUOR have done detailed paper studies of plants for use on coal derived streams. None of the processes have been applied to large scale commercial power plants of any type.

Notes 9&10:- MHI have active laboratory and pilot plant programmes in place for the development of their amine technology. FLUOR have theoretical and contract research programmes in place and still have access to the operating experience being gathered on the Bellingham plant. None of the technology developers have pilot plants operating on slip streams from coal or gas turbine fuelled power plants.

Table D7

Multifactorial Comparison of Commercial Amine Scrubbing Technologies

FACTOR	NOTES	KS-1 (MHI)	EFG Plus (MEA) (FLUOR)	Kerr McGee (MEA) (ABB Lummus Global)
Gas pretreatment to lower SO_2 / NO_2 required?	1	yes	yes	yes
Scaleable to commercial power plant sizes	2	yes	yes	yes
Energy use	3	Lowest	Close to KS-1	highest
Capex	4	Close to Fluor	lowest	highest
Opex	5	High	High	High
Solvent cost	6	High	Low	Lowest
Commercial Experience	7	1 plant	>20 plants	3 plants
Coal based plants built	8	none	none	Yes; all 3 plants are coal based
Process Development programmes ?	9	Yes	Yes	?
Market position?	10	modest	modest	lower

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SECTION E

BASIC DATA FOR EACH CASE

1.0 Process Descriptions

1.1 Natural Gas Combined Cycle Power Plant without Carbon Dioxide Capture

Overview

This description should be read in conjunction with the process flow diagram Drawing E1 and the mass balance tables which provides stream flows, compositions and flowing conditions (these documents are appended at the end of this section).

The design for CASE 1 is based on the use of two natural gas fired turbines each coupled with a heat recovery steam generator (HRSG) to generate steam for a single steam turbine generator. There is no CO_2 capture and it is a standard industry design which has been built many times in this configuration using GE or equivalent Frame 9F turbines. The plant has been simulated using GTPRO for the site gas and conditions as given in Section C Study Design basis. This software package contains the specific gas turbine data for the GE turbines.

Table B1 in Section B of this report shows a breakdown of the estimated performance of this case.

An open Brayton cycle using air and combustion products as the working fluid is used in conjunction with a sub critical Rankine Cycle in the steam turbines. These two cycles are coupled by the generation and superheating of steam in the HRSG and by feed water preheating in the HRSG. The HRSG uses a triple pressure reheat configuration.

The plant has a gross output of 800 MWe and achieves a gross efficiency (LHV) of 57.31%. Net plant output which considers generator losses and auxiliary power requirements for utility systems is 24 MWe and this reduces the output to a net value of 776 MWe. The overall efficiency of the plant defined as net power out / heat input on LHV basis is 55.59%.

Gas Turbines

Air is compressed in a single spool compressor to a pressure ratio of about 15:1. The compressor air passes to the combustion chamber of the turbine where it is mixed in dry low NOx combustors with natural gas fuel. The natural gas is burnt in dry low NOx combustors.

Hot combustion products are expanded through the gas turbine where they generate power and the gases exit into the HRSG, one for each turbine. Flue gas passes through the HRSG surrendering its heat to exit at a temperature of 101 degrees C.

HRSG

The Heat Recovery Steam Generator (HRSG) system recovers heat from the hot gas turbine exhaust gas and generates steam for use by the steam turbine.

The HRSG generates steam at three pressure levels (HP, IP and LP) and contains a reheat (RH) section. The vacuum condensate pumps feed the HRSG with LP feedwater whilst the HP/IP feedwater pumps provide HP and IP feedwater.

The plant has two identical HRSGs. The following description applies for train 1.

Each HRSG includes major equipment as follows:-

- **HP steam system**. Superheaters (primary and secondary), HPattemperator, evaporator, primary and secondary economizers and a steam drum.
- **IP steam system**. Superheater, evaporator, economiser and steam drum.
- **LP steam system** superheater, evaporator, economiser (feedwater heater) and steam drum.
- **Reheater (RH) system** RH coils (primary and secondary), RH attemperator
- **HP steam to cold reheat (CRH) bypass system**
- **Chemical injection**
- **Vents, drains and exhaust stack with stack damper.**

HP Steam System

The HP steam system receives HP feedwater from HP/IP feedwater pumps. It passes through primary and secondary economizers into the HP steam drum which is used to provide condensate to the evaporator coils and to separate steam from the condensate. The produced steam is heated in the superheated coils and flows into the main HP steam header.

The HRSG receives HP feedwater via a level control located on the HP BFW line upstream of the HP economiser inlet. As feedwater flows through the HP primary and secondary economisers it is heated by gas turbine exhaust gas and introduced into the HP steam drum. Steam produced in the HP steam drum passes through two sections of superheating coils with an HP attemperator between the two sections. The HP attemperator controls the final steam temperature leaving the HRSG boundary by adding HP feedwater if necessary.

Continuous blowdown is flashed to the IP drum and intermittent blowdown is let down into the atmospheric blowdown drum.

The HP steam header pressure floats on the steam turbine generator pressure with a minimum floor pressure of 60 barg. This pressure control scheme is performed by the steam turbine stop/control valves operating in inlet pressure control mode.

IP Steam System

The IP steam system receives IP feedwater from the HP/IP feedwater pumps. The IP economizer heats IP feedwater for the IP steam drum and GT fuel gas preheating. The IP steam drum provides condensate to the evaporator coils and separates steam from the condensate. The produced steam passes through the IP superheater coils and mixes with cold reheat steam (CRH) from the steam turbine. The combined IP superheated steam and the CRH enters the HRSG reheater (RH) section.

Feedwater from the HP/IP feedwater pumps IP interstage bleed maintains the IP steam drum normal level using a flow control valve located upstream of the IP steam drum. The feedwater flow downstream of the IP economizer splits to the IP steam drum and the fuel gas preheaters. A temperature control valve controls the flow rate of the hot IP feedwater to the fuel gas preheater.

Continuous blowdown is let down to the continuous blowdown tank and intermittent blowdown to the atmospheric blowdown tank.

LP Steam System

The LP steam system is fed with condensate from the condenser hotwell via the vacuum condensate return pumps. The LP steam drum provides water to the LP evaporator coils, separates steam from the feedwater and acts as the feedwater source for the HP/IP feedwater pumps. LP steam is superheated and flows to the LP steam admission valve on the steam turbine. Condensate from the vacuum condensate pumps maintains the LP steam drum level using a flow control valve located downstream of the HRSG feedwater economiser.

The LP steam drum also provides the storage source for the HP/IP feedwater pump. From the pump, HP and IP feedwater flows to various systems such as HP and IP economizers, HP and IP attemperators and HP to CRH bypass valve. Flashed steam from the continuous blowdown drum and HP/IP feedwater pump minimum flow bypass also enter the LP steam drum. Flashed steam conserves energy from the continuous blowdown of the IP steam drum. Intermittent blowdown is let down to the atmospheric blowdown tank.

Steam Turbine Generator

The Rankine cycle used in this plant is based on a single reheat configuration. The turbine cycle operates with the following steam conditions (pressure Bara/Temp Degrees C):-

HP Inlet	**125/550**
HP outlet	**30.3/345**
IP inlet	**27/560**
IP outlet	**5.29/288**
LP Inlet	**5.29/288**
Condenser	**0.05/33**

Condensate and Feedwater

Steam is condensed in the surface condenser which is close coupled to the LP turbine outlet. Vacuum is maintained by an IP steam driven vacuum system. The condenser is arranged to allow for deaeration of the boiler feed water (thus obviating the need for a separate deaerator vessel), comprising the vacuum condensate plus demineralised make up water. This makeup is needed to compensate for losses and blowdown from the boiler drums.

The condensers are cooled by means of once through sea water cooling.

Balance of Plant

This comprises all the systems necessary to allow operation of the plant and export of the produced power as shown on the outline equipment listing in Section F.

1.2 Natural Gas Combined Cycle Power Plant with Carbon Dioxide Capture

Overview

This description for CASE 2 should be read in conjunction with the process flow diagrams Drawing E2-E5 and the mass balance tables which provide stream flows, compositions and flow conditions.

This design is based on the use of two natural gas fired turbines each coupled with a heat recovery steam generator (HRSG) to generate steam for a single steam turbine generator. It is a modified standard industry design which has been built many times in this configuration using GE or equivalent Frame 9F turbines.

Modifications have been made to accommodate for the large amount of LP steam extract form the power cycle to feed the MEA stripping plant in the carbon dioxide capture plant. The plant has been simulated using GTPRO for the site gas and conditions as given in Section C Study Design basis. This software package contains the specific gas turbine data for the GE turbines. The carbon dioxide capture plant is based on use of FLUOR's ECONAMINE FG +^{SM}) process which has been simulated by FLUOR using a specialized ASPEN plus model which contains the necessary kinetic and absorption with chemical reaction routines to properly design the unit.

Table B1 in Section B of this report shows a breakdown of the estimated performance of this case.

An open Brayton cycle using air and combustion products as the working fluid is used in conjunction with a sub critical Rankine Cycle in the steam turbines. These two cycles are coupled by the generation and superheating of steam in the HRSG and by feed water preheating in the HRSG. The HRSG uses a triple pressure configuration and the low pressure. Unlike CASE 1, this plant includes a separate deaerator to ensure adequate degassing of the return condensate form the capture plant.

The plant has a gross output of 740 MWe and achieves a gross efficiency (LHV) of 53.01%. Net plant output which considers generator losses and auxiliary power requirements for utility systems, CO_2 capture and compression is 78 MWe and this reduces the output to a net value of 662 MWe. The overall efficiency of the plant defined as net power out /heat input on LHV basis is 47.42%.

This represents a loss of about 8 efficiency points compared with Case 1 and this can be interpreted as the true "bottom line" energy loss incurred by carbon capture fitted to an NGCC plant.

Gas Turbines

Air is compressed in a single spool compressor to a pressure ratio of about 15:1. The compressor air passes to the combustion chamber of the turbine where it is mixed in dry low NOx combustors with natural gas fuel. The natural gas is burnt in dry low NOx combustors.

Hot combustion products are expanded through the gas turbine where they generate power and the gases exit into the HRSG, one for each turbine. Flue gas passes through the HRSG surrendering its heat to exit at a temperature of 101 degrees C.

HRSG

This is configured with HP, IP and LP steam drums and circuitry as per CASE 1. Recycled vacuum condensate plus make up demineralised water are pumped through the FW economizer and into the LP steam drum where partial vaporization takes place to produce some LP steam which is superheated in the LP superheater prior to admission to the steam turbine.

Unvapourised water is pumped from LP drum through HP economisers into the HP drum where it is vaporized to produce HP steam. This is superheated in further hotter sections of the HRSG and is used as the feed to the front end of the steam turbine. This steam expands in the turbine and exits as IP steam which is reheated in the HRSG and passed to the IP section of the turbine. This IP steam is supplemented by IP steam generated in the IP steam drum, economizer and superheaters which are situated in the HRSG duct.

Extract steam for the carbon dioxide capture plant is take from the IP/LP crossover and desuperheater to 136 degrees C which is the condition required by the amine stripper reboiler in the capture plant

Steam Turbine generator

The Rankine cycle used in this plant is based on a single reheat configuration. The turbine cycle operates with the following steam conditions (pressure Bara/Temp Degrees C):-

HP Inlet	**125/550**
HP outlet	**30.3/345**
IP inlet	**27/560**
IP outlet	**3.5/277**
LP Inlet	**3.5/277**
Condenser	**0.05/33**
Extract	**3.24/136 to capture plant**

The cycle has been modified to operate with an outlet condition from the IP/LP turbine which is as close as possible to the LP steam condition required in the capture plant stripper reboiler. Because of these changes and because the mass flow of the steam through the LP turbines is drastically reduced (due to the extract) the gross output drops from CASE 1 800MWe to CASE 2 740 MWe.

Condensate and Feedwater

Steam is condensed in the surface condenser which is close coupled to the LP turbine outlet. Vacuum is maintained by an IP steam driven vacuum system. Condensate from the condenser is deaerated in a stand alone vessel which is required to deaerate the condensate returned from the capture plant amine stripper reboiler.

The condensers are cooled by means of once through sea water cooling.

Balance of Plant

This comprises all the systems necessary to allow operation of the plant and export of the produced power as shown on the outline equipment listing in Section F.

Carbon Dioxide Capture Plant

This is shown on Drawing E3 and E4 in the PFD section.

Hot flue gas from the discharge duct of the HRSGs flows into direct contact quench coolers (three streams) where it is contacted with cooled, circulating water. This adiabatic saturation process cools the gas to about 50 degrees Centigrade. The cooled gas is blown into three MEA absorbers arranged in a parallel configuration where it is contacted in a first packed bed with a countercurrent flow of semi regenerated MEA. Further contact takes place in the second bed with lean, fully regenerated MEA. Carbon dioxide is absorbed from the flue gas and the gas stream is then cooled in a direct contact quench bed at the top of the absorber. Some of the heat of reaction of amine with carbon dioxide is removed by pump around coolers which reject the heat to cooling water. Before leaving the column, the gas is scrubbed with make up water to remove any entrained MEA and the gas is then discharged to atmosphere from the top of the absorbers via a short stack section mounted on the absorber top. The gas is discharged to atmosphere at 55 degrees C.

Amine Regeneration

Rich amine is pumped from the bottom of the absorbers and is split into two streams. The first is heated in a cross exchanger with hot stripper bottoms and the preheated rich amine flows to the stripper. The other part of the stream is flashed to produce steam which is used in the stripping column and this reduces the amount of steam needed in the reboiler. The rich amine prior to being flashed is heated in a pair of exchangers (semi-lean MEA cooler where it is cross exchanged with hot flashed semi lean amine from the flash drum and Flash preheater which is heated by hot stripper bottoms on their way to the amine cross exchanger).

This flash, as well as producing additional stripping steam, partially desorbs carbon dioxide and creates a semi lean amine stream which is introduced back into the absorber first mass transfer bed.

The fully stripped amine stripper bottoms are re-introduced into the second absorber bed after they have been cooled, finally, in the lean solvent cooler.

Hot rich MEA is regenerated in the stripping column which has a stripping and rectification section. Flash steam plus some CO_2 from the amine flash drum is used in the top rectifying section of the column. Column traffic in the lower section is created by vertical thermosyphon reboilers arranged around the base of the stripping column. These reboilers are heated by condensing the steam extract from the IP/LP cross over in the power island. Condensate at saturation conditions is returned to the power island deaeration system.

Overhead vapour from the column passes through a disentrainment section and into the column overhead condenser where it is cooled with sea water. A two phase mixture of water and carbon dioxide vapour is disengaged in the overhead accumulator and some of the water is returned to the column as reflux. The excess condensed water is pumped to storage. This water is very clean.

Periodically some of the circulating amine is sent to the reclaimer where it is distilled with sodium carbonate to break down some of the heat stable salts which are formed from the reaction of trace impurities with the MEA. The heavy residues remaining after this batch regeneration are pumped away for disposal.

MEA is made up into the system from the amine storage tanks.

Carbon Dioxide Compression

Carbon dioxide from the stripper is compressed to a pressure of 74 bara by means of a four stage compressor. The compression includes interstage cooling and knockout drums to remove and collect condensed water. The carbon dioxide is dehydrated to remove water to a very low level. Beyond the critical point a booster pump is used for the final stage of compression to deliver a dense phase carbon dioxide stream at pipeline pressure assumed to be 110 bara.

Additional Off-Site Facilities

Additional off-site facilities are required over and above those needed for CASE 1. These include amine tanks, pumps and collection sumps.

1.3 Ultra Supercritical Pulverized Fuel Power Plant without Carbon Dioxide Capture

Overview

This description should be read in conjunction with block flow diagrams E6 and E7.

CASE 3 is a pulverized coal fired ultra supercritical steam plant. The design is a market based design.

The boiler is staged for low NOx production and is fitted with SCR for NOx abatement and a forced oxidation limestone/gypsum wet FGD system to limit emissions of sulphur dioxide. A once through steam generator of the two-pass BENSON design is used to power a single reheat ultra supercritical steam turbine.

Table B1 in section B of this report shows a breakdown of the estimated performance of this case.

The plant has a gross output of 831 MWe and achieves a gross efficiency (LHV) of 48.23%. Net plant output which considers generator losses and auxiliary power requirements for utility systems is 73 MWe and this reduces the output to a net value of 758 MWe. The overall efficiency of the plant defined as net power out / heat input on LHV basis is 43.98%.

Coal Handling

A coal handling system is provided to unload, convey, prepare and store the coal delivered to the plant.

Coal is delivered to the site by rail. Train cars are unloaded into hoppers from which the coal is conveyed to the reclaim area. Coal passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal is reclaimed and conveyed on belt conveyors which transfer it to a surge bin located in the crusher tower. The coal is reduced in size by means of a crusher and is then transferred by conveyor to silos from which it is conveyed and fed by weight feeders into mills for pulverization. Pulverised coal exits each mill via the coal piping and is distributed to the coal burners in the furnace front and rear walls.

Coal Combustion

Each coal burner is designed as a low NOx burner with staging of the coal combustion to minimize NOx formation. In addition, additional overfire air is introduced to cool rising combustion products to inhibit NOx formation.

Air from the FD fans is preheated by contact with exhaust gases through regenerative preheaters. This preheated air is distributed to the burner wind box as secondary air. A portion of the air supply (primary air) is routed around the air preheaters and is used as tempering air in the coal pulverisers. Preheated primary air and tempering air are mixed at each pulveriser to obtain the desired pulveriser fuel-air mixture and transport the pulverized fuel to the coal burners.

Hot combustion products exit the furnace and pass through to the radiative and convective heating surfaces and the downstream regenerative preheaters after providing steam generation and steam reheat and thence to the flue gas clean-up plant comprising of the ESP and FGD plant.

Steam Raising

Feedwater enters the economizer, recovers heat from the combustion gases and then passes to the water wall circuits enclosing the furnace. The fluid then passes through heating surface banks to convective primary superheat, radiative secondary superheat and then to convective final superheat. The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and is returned to the IP turbine.

Soot and Ash Handling

A steam fed soot blowing system is provided with an array of retractable nozzles and lances which travel forward to the blowing position, rotate through the blowing cycle and are then withdrawn.

The furnace bottom comprises hoppers with a clinker grinding system situated below it. Ash passes through the clinker grinder to the ash handling system.

Fly ash is collected from the discharge hoppers on the economisers and on the ESPs.

DENOX

SCR is provided to reduce the NOx produced by the boiler from about 317 ppm @ 6%O2 v/v, dry to less than 100 ppm @ 6% O2 v/v, dry. The catalytic DENOX reactor is situated in the gas stream between the boiler outlet and the air preheaters. The reactors consist of catalyst tiers arranged in a number of units with space allowed for future units. A system of rails and runway beams is incorporated for initial and future catalyst loading.

Gaseous ammonia is added to air supplied from the FD fan in a mixer and is injected into the flue gas via a grid of headers and nozzles in a horizontal flue shortly after the boiler. Turning vanes are incorporated to ensure good distribution. Further details and performance data of the system are on the Mitsui Babcock data sheets at the end of this section.

Flue Gas Desulphurization

Flue gas desulphurization is provided to reduce the sulphur dioxide level in the flue gas from the boiler to around 70 ppm @ 6%O2 v/v, dry from an expected inlet level of about 660 ppm @ 6%O2 v/v, dry based on the specified coal quality. The plant is described in the ALSTOM Power attachment at the end of this section.

Steam Turbine Generator

The turbine consists of a HP, IP and LP sections all connected to the generator with a common shaft. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating and is then throttled into the double flow IP turbine. Exhaust steam form the IP turbines then flows into the double flow LP turbine system. Boiler and turbine interface data are as follows:

HP turbine inlet	290 Bara/600 Degrees C
HP exhaust	64.5/363 Bara/600 Degrees C
IP Turbine Inlet	60/620 Bara/600 Degrees C
LP Turbine Inlet	8 Bara
Condenser Pressure	0.04 Bara

Feedwater Heating Systems

Recycled vacuum condensate from the condenser hot well is preheated in a bank of preheaters which are fed with extract steam form the LP turbines. The preheated feedwater stream is then deaerated in the deaerator which is fed with a bleed of IP steam from the IP turbine exit which also deaerates make up demineralised water. Following the deaerator a further bank of preheaters preheats the feed water 300 Degrees C prior to the boiler. These heaters are heated by IP turbine extract and finally by HP steam extracts from the turbines.

Balance of Plant

This comprises all the systems necessary to allow operation of the plant and export of the produced power as shown on the outline equipment listing in Section F.

1.4 Ultra Supercritical Pulverized Fuel Power Plant with Carbon Dioxide Capture

Overview

This description should be read in conjunction with block flow diagrams E8-E12

CASE 4 is a pulverized coal fired ultra supercritical steam plant. The design is a market based design and is fitted with a carbon dioxide capture and compression plant.

The boiler is staged for low NOx production and is fitted with SCR for NOx abatement and a forced oxidation limestone/gypsum wet FGD system to limit emissions of sulphur dioxide. A once through steam generator of the two-pass BENSON design is used to power a single reheat ultra supercritical steam turbine.

Table B1 in section B of this report shows a breakdown of the estimated performance of this case.

The plant has a gross output of 827 MWe and achieves a gross efficiency (LHV) of 48.23%. Net plant output which considers generator losses and auxiliary power requirements for utility systems is 161 MWe and this reduces the output to a net value of 666 MWe. The overall efficiency of the plant defined as net power out / heat input on LHV basis is 34.79%.

Coal Handling

A coal handling system is provided to unload convey, prepare and store the coal delivered to the plant.

Coal is delivered to the site by rail. Train cars are unloaded into hoppers from which the coal is conveyed to the reclaim area. Coal passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal is reclaimed and conveyed on belt conveyors which transfer it to a surge bin located in the crusher tower. The coal is reduced in size by means of a crusher and is then transferred by conveyor to silos from which it is conveyed and fed by weight feeders into mills for pulverization. Pulverised coal exits each mill via the coal piping and is distributed to the coal burners in the furnace front and rear walls.

Coal Combustion

Each coal burner is designed as a low NOx burner with staging of the coal combustion to minimize NOx formation. In addition, additional overfire air is introduced to cool rising combustion products to inhibit NOx formation.

Air from the FD fans is preheated by contact with exhaust gases through regenerative preheaters. This preheated air is distributed to the burner wind box as secondary air. A portion of the air (primary air) supply is routed around the air preheaters and is used as tempering air in the coal pulverisers. Preheated primary air and tempering air are mixed at each pulveriser to obtain the desired pulveriser fuel-air mixture and transport the pulverized fuel to the coal burners.

Hot combustion products exit the furnace and pass through to the radiative and convective heating surfaces and the downstream regenerative preheaters after providing steam generation and steam reheat and thence to the flue gas clean-up plant comprising of the ESP and FGD plant.

Steam Raising

Feedwater enters the economizer, recovers heat from the combustion gases and then passes to the water wall circuits enclosing the furnace. The fluid then passes through heating surface banks to convective primary superheat, radiative secondary superheat and then to final superheat. The steam then exits the steam generator enroute to the HP turbine. Returning cold reheat steam passes through the reheater and is returned to the IP turbine.

Soot and Ash Handling

A steam fed soot blowing system is provided with an array of retractable nozzles and lances which travel forward to the blowing position, rotate through the blowing cycle and are the withdrawn.

The furnace bottom comprises hoppers with a clinker grinding system situated below it. Ash passes through the clinker grinder to the ash handling system.

Fly ash is collected from the discharge hoppers on the economisers and on the ESPs.

DENOX

SCR is provided to reduce the NOx produced by the boiler form about 317 ppm @ 6% O2 v/v, dry to a level which does not exceed the inlet requirement of the carbon dioxide capture plant which corresponds to less than 20 ppmv @ 6%O2 v/v, dry of NO_2. In fact this specification is exceeded and the SCR plant will reduce NO_2 to around 5 ppm @ 6%O2 v/v, dry.

The catalytic DENOX reactor is situated in the gas stream between the boiler outlet and the air heaters. The reactors consist of catalyst tiers arranged in a number of units with space allowed for future units. A system of rails and runway beams is incorporated for initial and future catalyst loading.

Gaseous ammonia is added to air supplied from the FD fan in a mixer and is injected into the flue gas via a grid of headers and nozzles in a horizontal flue shortly after the boiler. Turning vanes are incorporated to ensure good distribution. Further details and performance data of the system are on the Mitsui Babcock data sheets at the end of this section.

Flue Gas Desulphurization

Flue gas desulphurization is provided to reduce the sulphur dioxide level in the flue gas from the boiler to around 10 ppm @ 6%O2 v/v, dry from an expected inlet level of about 660 ppm @ 6%O2 v/v, dry. In this case a much greater degree of desulphurization is required to reduce the sulphur dioxide concentration at the inlet of the carbon dioxide capture plant to 10 ppm max. The plant is described in the ALSTOM Power attachment at the end of this section.

Steam Turbine Generator

The turbine consists of a HP, IP and LP sections all connected to the generator with a common shaft. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating and is then throttled into the double flow IP turbine. Exhaust steam from the IP turbines then flows into the double flow LP turbine system. The LP turbine conditions are changed (compared with CASE 3) to allow for the extraction of steam from the IP turbine outlet at the required extract pressure for the amine stripper reboiler. Boiler and turbine interface data are as follows:

HP turbine inlet	290 Bara/600 Degrees C
HP exhaust	64.5/363 Bara/600 Degrees C
IP Turbine Inlet	60/620 Bara/600 Degrees C
LP Turbine Inlet	3.6 Bara
Condenser Pressure	0.04 Bara

Feedwater Heating Systems

Recycled vacuum condensate from the condenser hot well is pumped to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and the carbon dioxide compressor intercoolers. About 96 MWe of heat are picked up and this obviates the need for LP steam extracts in the preheat train. The preheated feedwater stream is then deaerated in the deaerator which is fed with a bleed of IP steam from the IP turbine exit which also deaerates make up demineralised water and condensate returned from the amine stripper reboiler. Following the deaerator a further bank of preheaters preheats the feed water 300 Degrees C prior to the boiler. These heaters are heated by IP turbine extract and finally by HP steam extracts from the turbines.

Balance of Plant

This comprises all the systems necessary to allow operation of the plant and export of the produced power as shown on the outline equipment listing in Section F.

Carbon Dioxide Capture Plant

This is shown on Drawing E10-E12 in the PFD section.

Treated flue gas from the FGD plant flows into a direct contact quench coolers (two streams) where it is contacted with cooled, circulating water. This adiabatic saturation process cools the gas. The cooled gas is blown into two MEA absorbers arranged in a parallel configuration where it is contacted in a first packed bed with a countercurrent flow of semi regenerated MEA. Further contact takes place in the second bed with lean, fully regenerated MEA. Carbon dioxide is absorbed from the flue gas and the gas stream is then cooled in a direct contact quench bed at the top of the absorber. Some of the heat of reaction of amine with carbon dioxide is removed by pump around coolers which reject the heat to cooling water. Additional reaction heat is removed from a pump around at the base of the absorption columns

In the case of a coal fired plant the gas volume is less than that from an NGCC plant of equivalent output and the concentration of carbon dioxide is much higher. This results in some changes to the flow sheets (fewer absorbers, changed heat balance).

Before leaving the column, the gas is scrubbed with make up water to remove any entrained MEA and the gas is then discharged to atmosphere from the top of the absorbers via a short stack section mounted on the absorber top. The gas is discharged to atmosphere at 55 degrees C.

Amine Regeneration

Rich amine is pumped from the bottom of the absorbers and is split into two streams. The first is heated in a cross exchanger with hot stripper bottoms and the preheated rich amine flows to the stripper. The other part of the stream is flashed to produce steam which is used in the stripping column and this reduces the amount of steam needed in the reboiler. The rich amine prior to being flashed is heated in a pair of exchangers (semi-lean MEA cooler where it is cross exchanged with hot flashed semi-lean amine from the flash drum and Flash preheater which is heated by hot stripper bottoms on their way to the amine cross exchanger).

This flash, as well as producing additional stripping steam, partially desorbs carbon dioxide and creates a semi-lean amine stream which is introduced back into the absorber first mass transfer bed.

The fully stripped amine stripper bottoms are re-introduced into the second absorber bed after they have been cooled, finally, in the lean solvent cooler.

Hot rich MEA is regenerated in the stripping column which has a stripping and rectification section. Flash steam plus some CO_2 from the amine flash drum is used in the top rectifying section of the column. Column traffic in the lower section is created by vertical thermosyphon reboilers arranged around the base of the stripping column. These reboilers are heated by condensing the steam extract from the IP/LP cross over in the power island. Condensate at saturation conditions is returned to the power island deaeration system.

Overhead vapour from the column passes through a disentrainment section and into the column overhead condenser where it is cooled with recycled condensate from the boiler island in a special set of tube passes. The remaining cooling duty is achieved with sea water. The flowsheet shows a single condenser with one cooling water stream but in reality this would be designed with multiple tube passes for cold condensate and seawater cooling to effect the thermal integration scheme. (There is a limit on the fraction of the heat load recoverable by recycle cold condensate in this condenser. This limit is set by the need to recover heat in the carbon dioxide compression train.)

A two-phase mixture of water and carbon dioxide vapour is disengaged in the overhead accumulator and some of the water is returned to the column as reflux. The excess condensed water is pumped to storage. This water is very clean.

Periodically some of the circulating amine is sent to the reclaimer where it is distilled with sodium carbonate to break down some of the heat stable salts which are formed from the reaction of trace impurities with the MEA. The heavy residues remaining after this batch regeneration are pumped away for disposal.

MEA is made up into the system from the amine storage tanks.

Carbon Dioxide Compression

Carbon dioxide from the stripper is compressed to a pressure of 74 bara by means of a four stage compressor. The compression includes interstage cooling (with both recycled condensate from the power island and trim cooling with sea water) and knockout drums to remove and collect condensed water. The carbon dioxide is dehydrated to remove water to a very low level. Beyond the critical point a booster pump is used for the final stage of compression to deliver a dense phase carbon dioxide stream at pipeline pressure assumed to be 110 bara.

Additional Off-Site Facilities

Additional off-site facilities are required over and above those needed for CASE 1. These include amine tanks, pumps and collection sumps.

2.0 Process Flow Diagrams

These are appended at the end of this section as follows:-.

- Drawing E1 Case 1 Natural Gas Combined Cycle Power Plant without CO_2 Capture : 2-off GE 9FA GasTurbines plus Steam Turbine
- Drawing E2 Case 2 Natural Gas Combined Cycle Power Plant with CO_2 Capture : 2-off GE 9FA GasTurbines plus Steam Turbine plus Exhaust Flue Gas CO_2 Recovery
- Drawing E3 Case 2 Natural Gas Combined Cycle Power Plant with CO_2 Capture : CO_2 Absorption and Amine Scrubbing
- Drawing E4 Case 2 Natural Gas Combined Cycle Power Plant with CO_2 Capture : MEA Heat Integration System
- Drawing E5 Case 2 Natural Gas Combined Cycle Power Plant with CO_2 Capture : CO_2 Compression System
- Drawing E6 Case 3 830 MWe Gross PF Power Plant Base Case : Block Flow Diagram : SCPF without Capture
- Drawing E7 USCPF Without Capture - Turbine Power Island
- Drawing E8 Case 4 827 MWe Gross PF Power Plant with CO_2 Capture Amine Scrubbing : Block Flow Diagram : SCPF with Capture
- Drawing E9 USCPF With Capture - Turbine Power Island
- Drawing E10 Case 4 Supercritical Steam Cycle with CO_2 Capture : CO_2 Absorption and Amine Scrubbing
- Drawing E11 Case 4 Supercritical Steam Cycle with CO_2 Capture : MEA Heat Integration System
- Drawing E11 Case 4 Supercritical Steam Cycle with CO_2 Capture : CO_2 Compression and Recovery System

3.0 Mass Balance Tables

These are appended at the end of this section as follows:-

- Case 1 : NGCC no Capture
- Case 2 : NGCC with Capture
- Case 3 : USCPF no Capture
- Case 4 : USCPF with Capture

4.0 Chemicals and Consumables Summaries

These are shown on the following Tables:-

- Case 1 : NGCC without Carbon Dioxide Capture
- Case 2 : NGCC with Carbon Dioxide Capture
- Case 3 : USC Pulverised Coal without Carbon Dioxide Capture
- Case 4 : USC Pulverised Coal PF with Carbon Dioxide Capture

Note that in these tables a cost is given for amine unit waste disposal but that these disposal costs are omitted from the cost of electricity calculations.

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CHEMICALS AND CONSUMABLE SUMMARIES

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CHEMICALS AND CONSUMABLES SUMMARY

CASE 1: NGCC WITHOUT CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	800	
Net Power output	MW	776	
CO2 emission	Tonnes/Hr	294.07	379 g/kWh
CO2 Recovered	Tonnes/Hr	Nil	
Fuel Feedrate			
Coal		Nil	
Natural gas	Tonnes/Hr	107.19	
Chemicals and consumables			
Make-up water	Tonnes/Hr	4.28	Cost at 0.1US$/tonne
Limestone		Nil	
Ammonia		Nil	
MEA solvent		Nil	
Amine inhibitors		Nil	
Miscellaneous	$/MWh	0.05	
Catalyst for DENOX		Nil	
Waste Disposal			
Bottom ash		Nil	
Fly ash		Nil	
Gypsum		Nil	
Chloride		Nil	
Amine unit waste		Nil	
Waste water	Tonnes/Hr	4.28	Blow down from HRSG
Number of operators		62	

CHEMICALS AND CONSUMABLES SUMMARY

CASE 2: NGCC WITH CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	740	
Net Power output	MW	662	
CO2 emission	Tonnes/Hr	44.11	444 g/kWh reduced to 66 g/KWh
CO2 Recovered	Tonnes/Hr	250.41	85% recovery
Fuel Feedrate			
Coal		Nil	
Natural gas	Tonnes/Hr	107.19	
Chemicals and consumables			
Make-up water	Tonnes/Hr	135.37	
Limestone		Nil	
Ammonia		Nil	
MEA solvent	Kg/Tonne CO2	1.6	1300US$/Tonne
Amine inhibitors	US$/Tonne CO2	0.53	
Activated carbon	Kg/Tonne CO2	0.06	1000US$/Tonne
Soda Ash	Kg/Tonne CO2	0.13	110US$/Tonne
Miscellaneous	$/MWh	0.1	Allowance
Catalyst for DENOX		Nil	
Waste Disposal			
Bottom ash		Nil	
Fly ash		Nil	
Gypsum		Nil	
Chloride		Nil	
Amine unit waste	Tonnes/Ton CO2	0.0032	250US$/Tonne disposal cost
Waste water	Tonnes/Hr	135	
Number of operators		68	

CHEMICALS AND CONSUMABLES SUMMARY

CASE 3: USCPF WITHOUT CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	831.00	
Net Power output	MW	758.00	
CO2 emission	Tonnes/Hr	563.00	This is equivalent to 743 g/kWh
CO2 Recovered		Nil	
Fuel Feedrate			
Coal	Tonnes/Hr	239.80	Coal priced at 46.6 Euros/tonne(55.92 $/tonne)
Natural gas		Nil	
Chemicals and consumables			
Make-up water	Tonnes/Hr	46.00	Cost at 0.1 $/tonne
Limestone	Tonnes/Hr	6.39	15US$/Tonne
Ammonia	Tonnes/Hr	0.42	336US$/Tonne
MEA solvent		Nil	
Amine inhibitors		Nil	
Miscellaneous	$/MWh	0.05	Allowance
Catalyst for DENOX	MM$	3.98	Based on a price of $300/ft3 of catalyst
Waste Disposal			
Bottom ash	Tonnes/Hr	7.31	
Fly ash	Tonnes/Hr	21.94	
Mill rejects	Tonnes/Hr	0.50	
Gypsum	Tonnes/Hr	11.58	From FGD plant at 9.5% water content
Chloride	Tonnes/Hr	0.60	Chloride purge from FGD plant
Amine unit waste		Nil	
Waste water	Tonnes/Hr	0.61	
Number of operators	Number	124	

CHEMICALS AND CONSUMABLES SUMMARY

CASE 4: USCPF WITH CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	827	
Net Power output	MW	666	
CO2 emission	Tonnes/Hr	78.13	This is equivalent to 117 g/kWh
CO2 Recovered	Tonnes/Hr	546.8	87.5% recovery
Fuel Feedrate			
Coal	Tonnes/Hr	266.256	Coal priced at 46.6 Euros/tonne (55.92$/Tonne)
Natural gas		Nil	
Chemicals and consumables			
Make-up water	Tonnes/Hr	237.5	Boiler plant/FGD/EFG+@0.1 US$/Tonne
Limestone	Tonnes/Hr	7.73	15US$/Tonne
Ammonia	Tonnes/Hr	0.465	336US$/Tonne
MEA solvent	Kg/Tonne CO2	1.6	1300US$/Tonne
Amine inhibitors	US$/Tonne CO2	0.53	
Activated carbon	Kg/Tonne CO2	0.06	1000US$/tonne
Soda ash	Kg/Tonne CO2	0.13	110$/Tonne
Miscellaneous	$/MWh	0.1	Allowance for power plant plus EFG+
Catalyst for DENOX	MM$	4.326	
Waste Disposal			
Bottom ash	Tonnes/Hr	8.121	
Fly ash	Tonnes/Hr	24.36	
Mill Rejects	Tonnes/Hr	0.5	
Gypsum	Tonnes/Hr	14.055	
Chloride	Tonnes/Hr	0.61	
Amine unit waste	Tonnes/TonCO2	0.0032	250US$/Tonne for disposal
Waste water	Tonnes/Hr	115	
Number of operators	Number	130	

5.0 Emissions From Plants

The plant emissions are shown on the following emissions summary Table H2.

Notes for this table are given below:

1. The SO_2 level at the absorber inlet has to be controlled at or below 10 ppmv @ 6% O2 v/v, dry in the capture cases to avoid excessive amine loss.

2. The specified cooling water rise of 7 degrees C is in fact very conservative and results in very high cooling water flows and this results in increased capital cost and parasitic power loss. It is quite probable that these sea water cooling quantities could be halved by adopting a larger maximum temperature rise provided that environmental regulatory limits on maximum discharge temperatures are not exceeded.

3. No allowances have been made in the economics calculation for disposal costs or for any by product credits as these are likely to be highly variable in real applications and are very scenario specific.

4. The amine unit waste is based on typical data. Reclaimer waste from the EFG process is similar to any refinery MEA reclaimer waste except that the EFG plant waste will contain some copper. A typical analysis is shown on Table H1 below based on the Fluor plant at Bellingham. Waste disposal companies charge about $1.0 per US gallon to dispose of this waste. These companies process the waste by removing the metals and then incinerating the remainder. This waste can also be disposed of in a cement kiln where the waste metals become agglomerated in the clinker.

5. NOx levels need controlling to ensure that there is less than 20 ppmv @ 6% O2 v/v, dry of NO_2 at the inlet to the absorbers in the carbon dioxide capture cases.

6. Mass balance quantities are extracted from the mass balance tables. It is anticipated that these quantities can be discharged to the atmosphere without any dispersion problems even when vented cold from the tops of the amine absorbers i.e. without fans and stacks to give additional draught.

7. Chlorides are purged from the FGD system on a periodic basis.

TABLE H 1 Analysis of Typical Reclaimer Waste

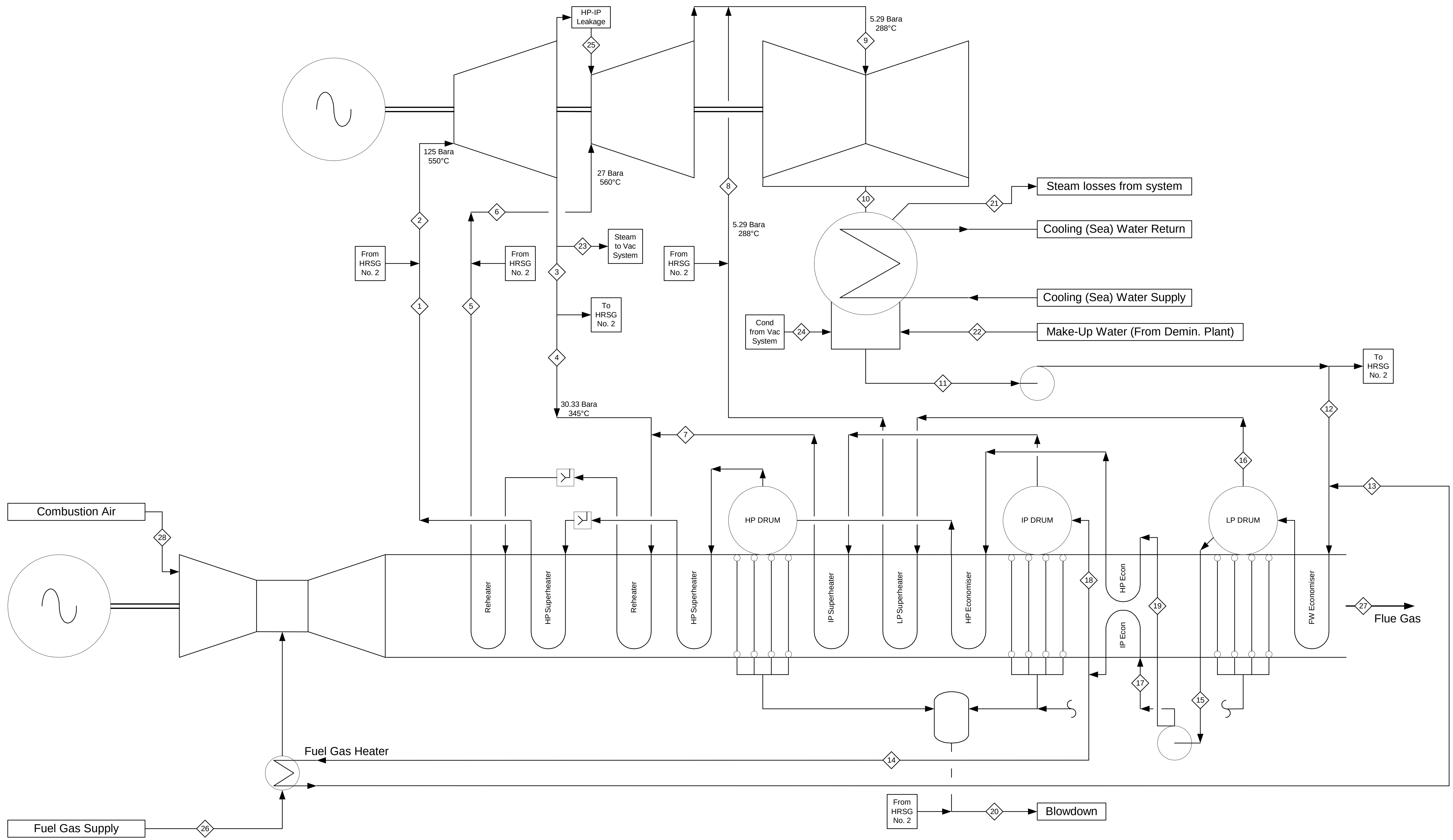
Ph	10.29
Water	33.9 Vol %
API gravity	0.7
Composition	
Cr	less than 2 ppm total
Cu	855 ppm
Fe	129 ppm
Ni	less than 2 ppm
Na	7500
MEA	6000 ppm

TABLE H2:- EMISSIONS SUMMARY

		CASE 1 NGCC	CASE 2 NGCC+Capture	CASE 3 USCPF	CASE 4 USCPF+Capture
Gross Output	MW	800	740	830	827
CO2 Emitted	Tonnes/Hr	294	43	560	95
	g/kWh	**368**	**58**	**675**	**115**
Flue gas	Tonnes/Hr	4733	4544	2973	2825
	Mol Wt				
Oxygen	Mol%	12.5	12.7	4.3	5.7
Carbon dioxide	Mol%	4	0.6	12.4	2.1
Water vapour	Mol%	7.8	10	12.2	10.1
Nitrogen	Mol%	75.7	76.7	71.1	82.1
SO_2	Mg/M_3	0.5	Nil	200	10
NO_2	Mg/M_3	<20	<20		<20
NO_X	Mg/M_3			200	
Particulates	Mg/M_3	Nil	Nil	Nil	Nil
MEA	ppmv	Nil	1	Nil	1
Waste Water	M_3/Hr	4	135	46	238
FGD Chloride purge	M_3/hr	Nil	Nil	0.6	0.6
Warm Sea Water	M_3/Hr	58000	88000	114000	280000
Solids Waste					
Flyash	Tonnes/Hr	Nil	Nil	22	24
Furnacee bottom ash	Tonnes/Hr	Nil	Nil	7.3	8.1
Mill Rejects(pyritic)	Tonnes/Hr	Nil	Nil	0.5	0.5
Gypsum Byproduct	Tonnes/Hr	Nil	Nil	11.6	14.1
Water Content	Wt %			9.5	9.4
Amine Unit Waste	Tonnes/Hr	Nil	0.79	Nil	1.75

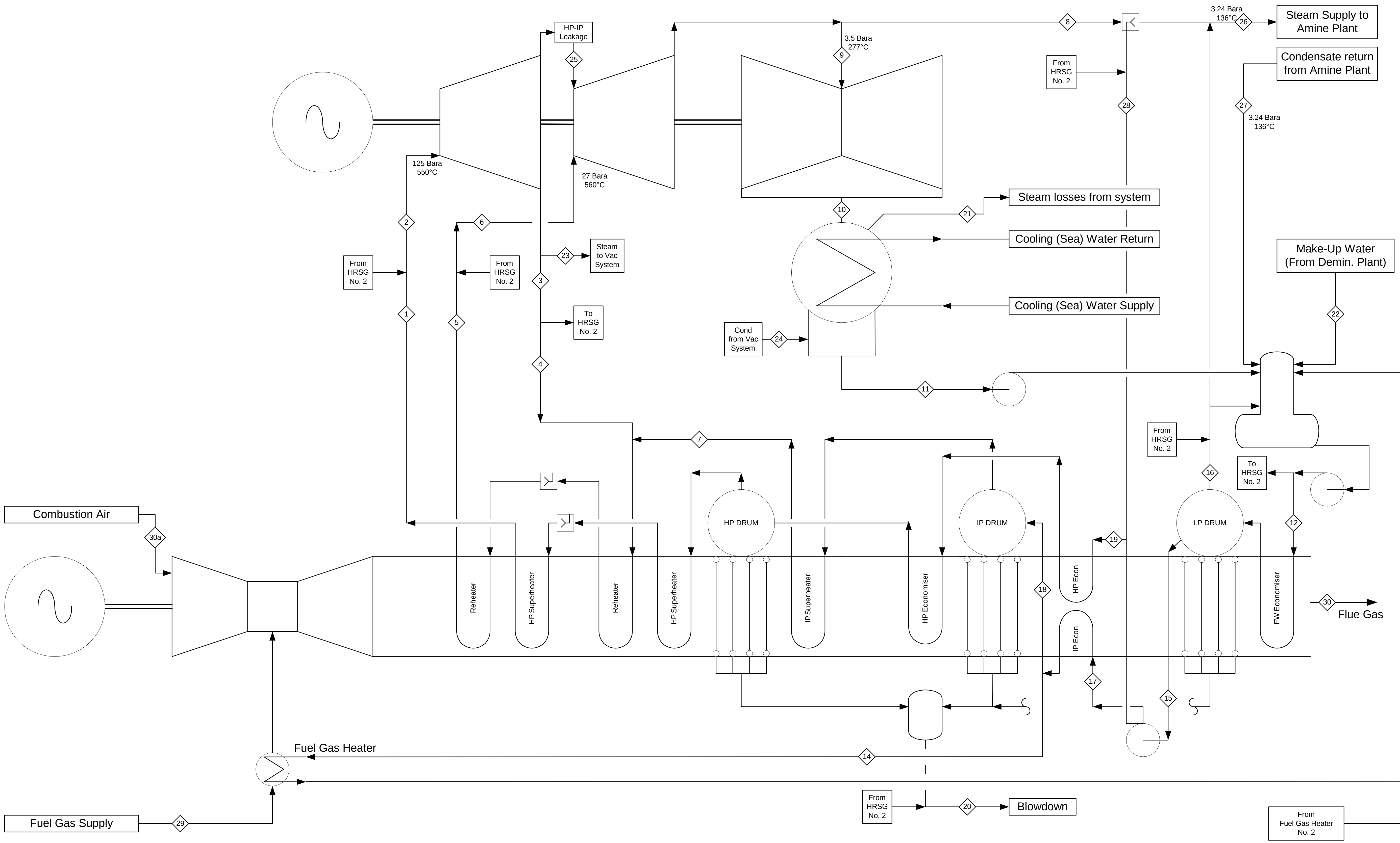
ATTACHMENTS TO THIS SECTION E

1. **PROCESS FLOW DIAGRAMS**
2. **HEAT AND MASS BALANCE TABLE**
3. **ALSTOM FGD PLANT DESCRIPTION AND DATA**
4. **DENOX DATASHEET**



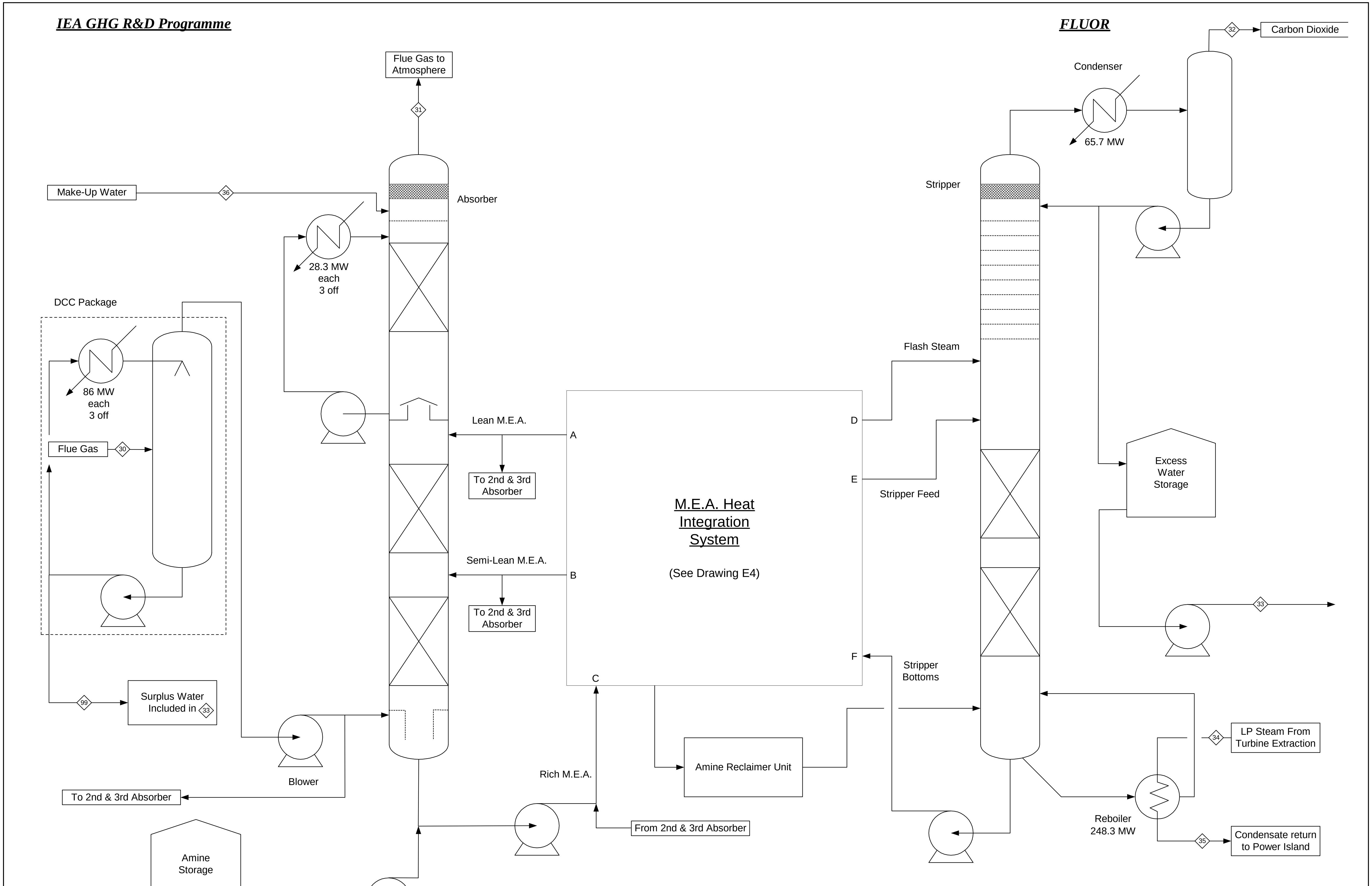
Drawing E1 Case1 Natural Gas Combined Cycle Power Plant without CO_2 Capture

2off GE 9FA Gas Turbines plus Steam Turbine



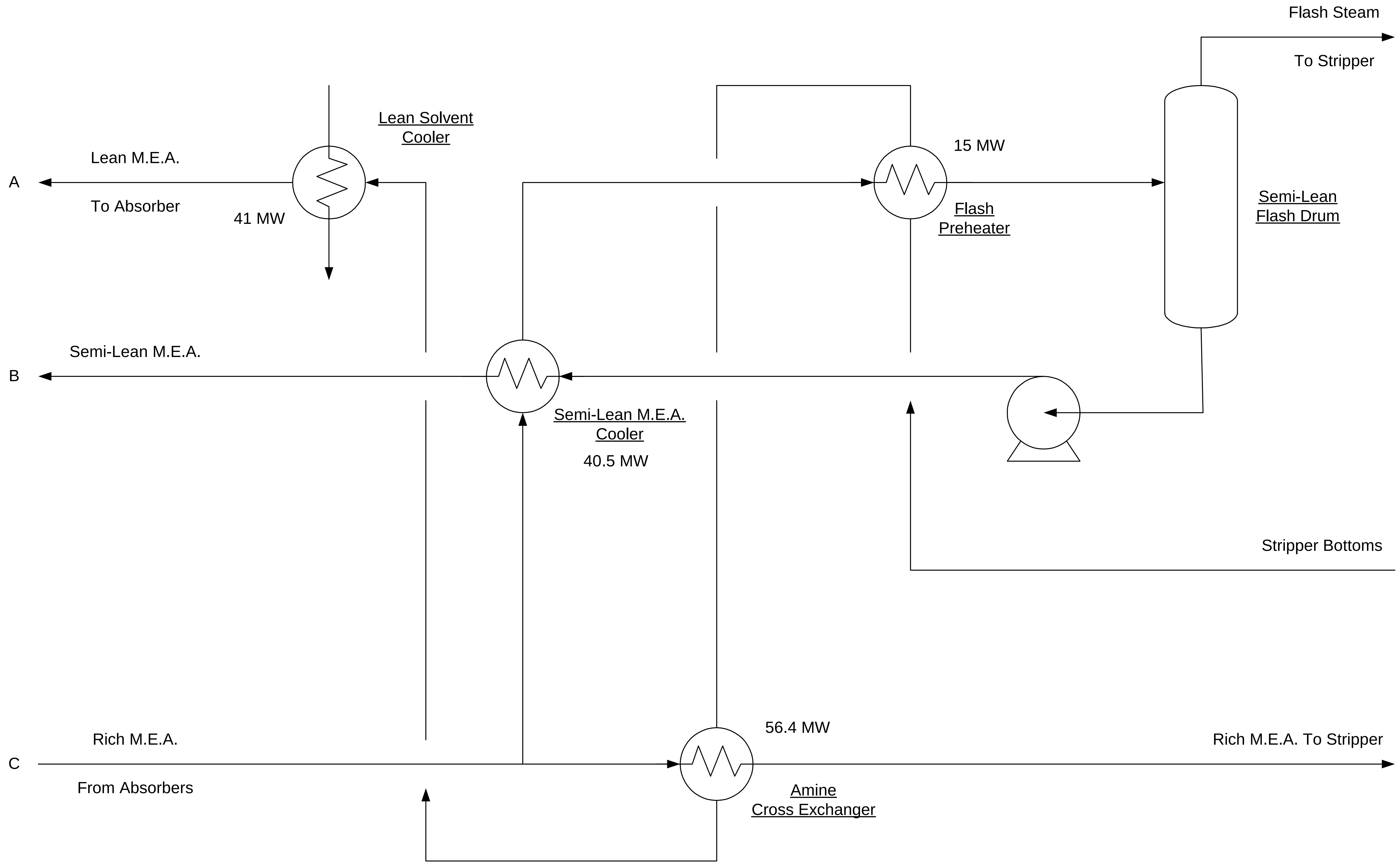
Drawing E2 Case2 Natural Gas Combined Cycle Power Plant with CO_2 Capture

2off GE 9FA Gas Turbines plus Steam Turbine plus Exhaust Flue Gas CO_2 Recovery



Drawing E3 Case2 Natural Gas Combined Cycle Power Plant with CO_2 Capture

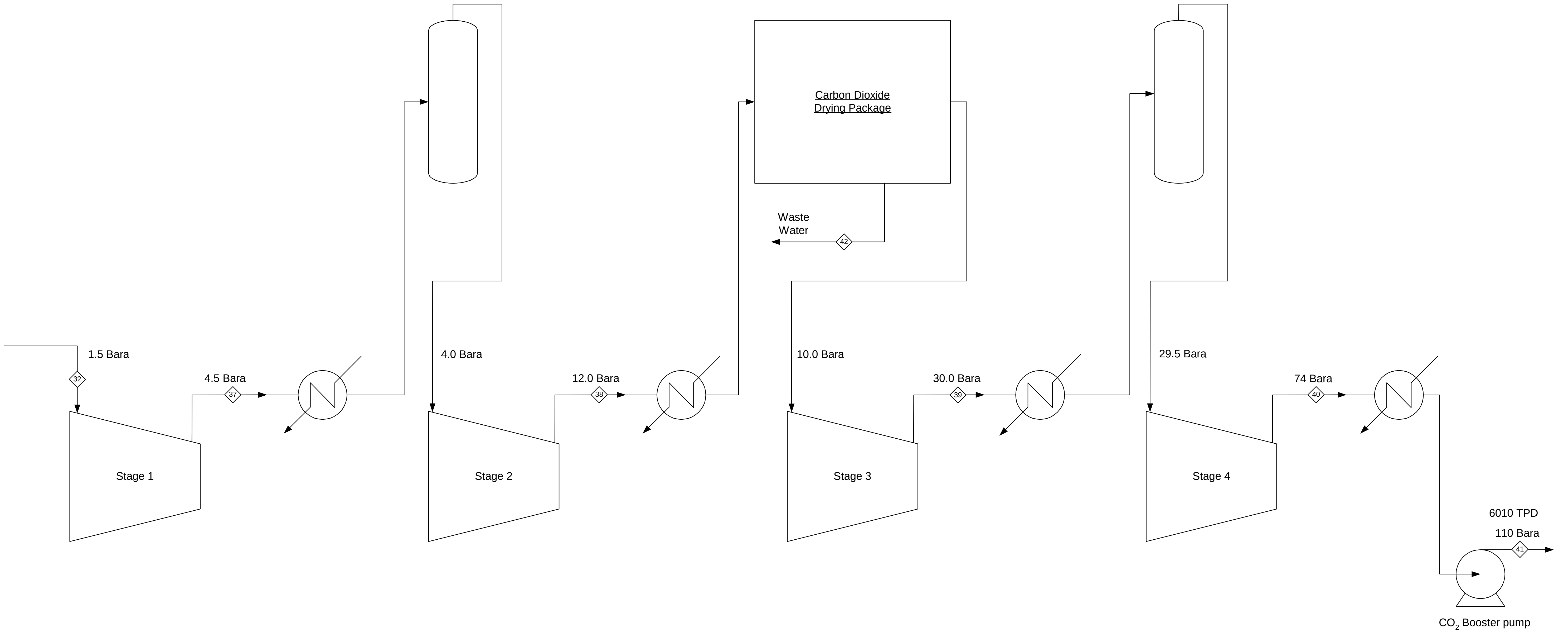
CO_2 Absorption and Amine Stripping



Drawing E4 Case2 Natural Gas Combined Cycle Power Plant with CO_2 Capture

M.E.A. Heat Integration System

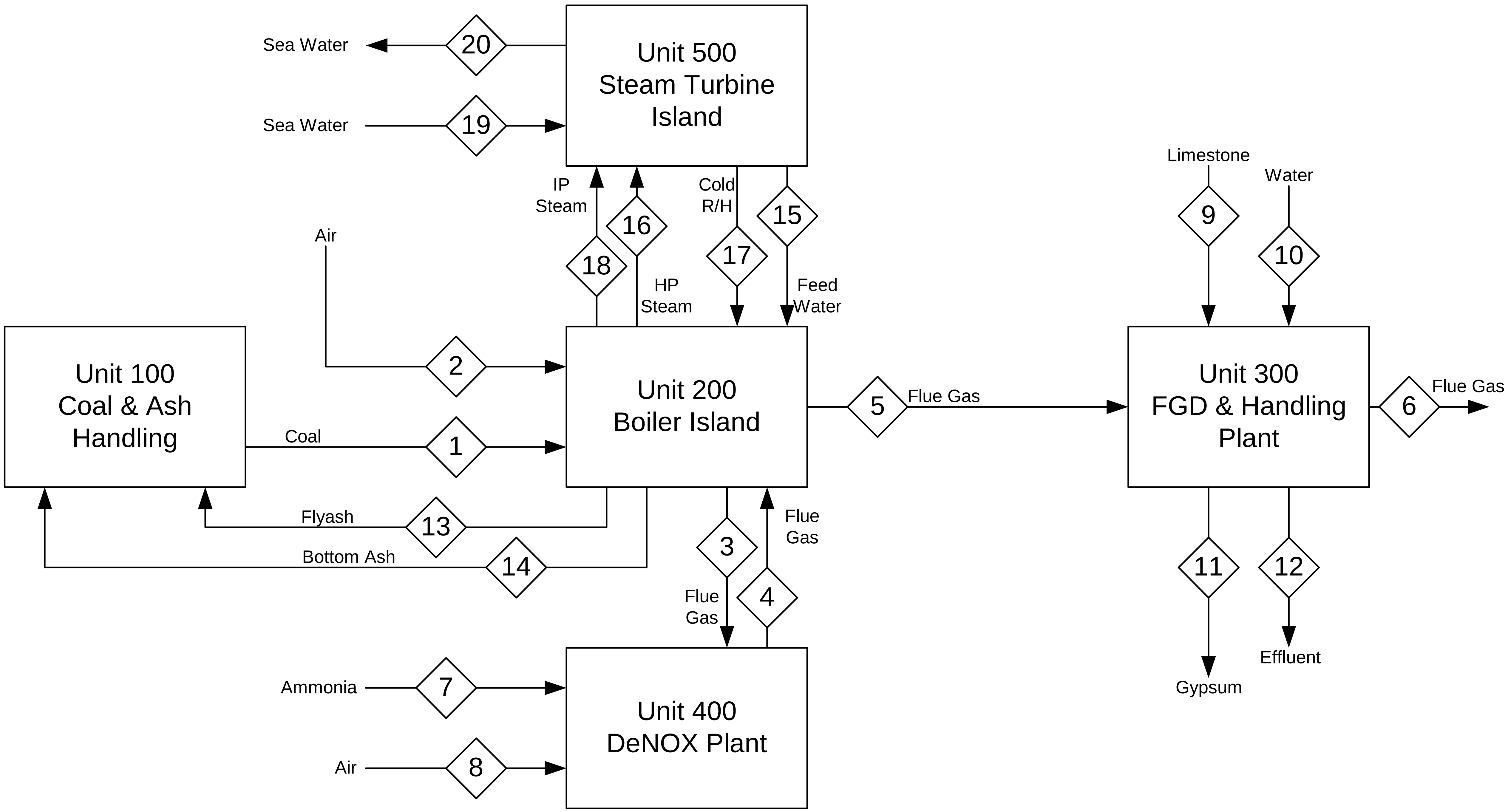
IEA GHG R&D Programme ***FLUOR***

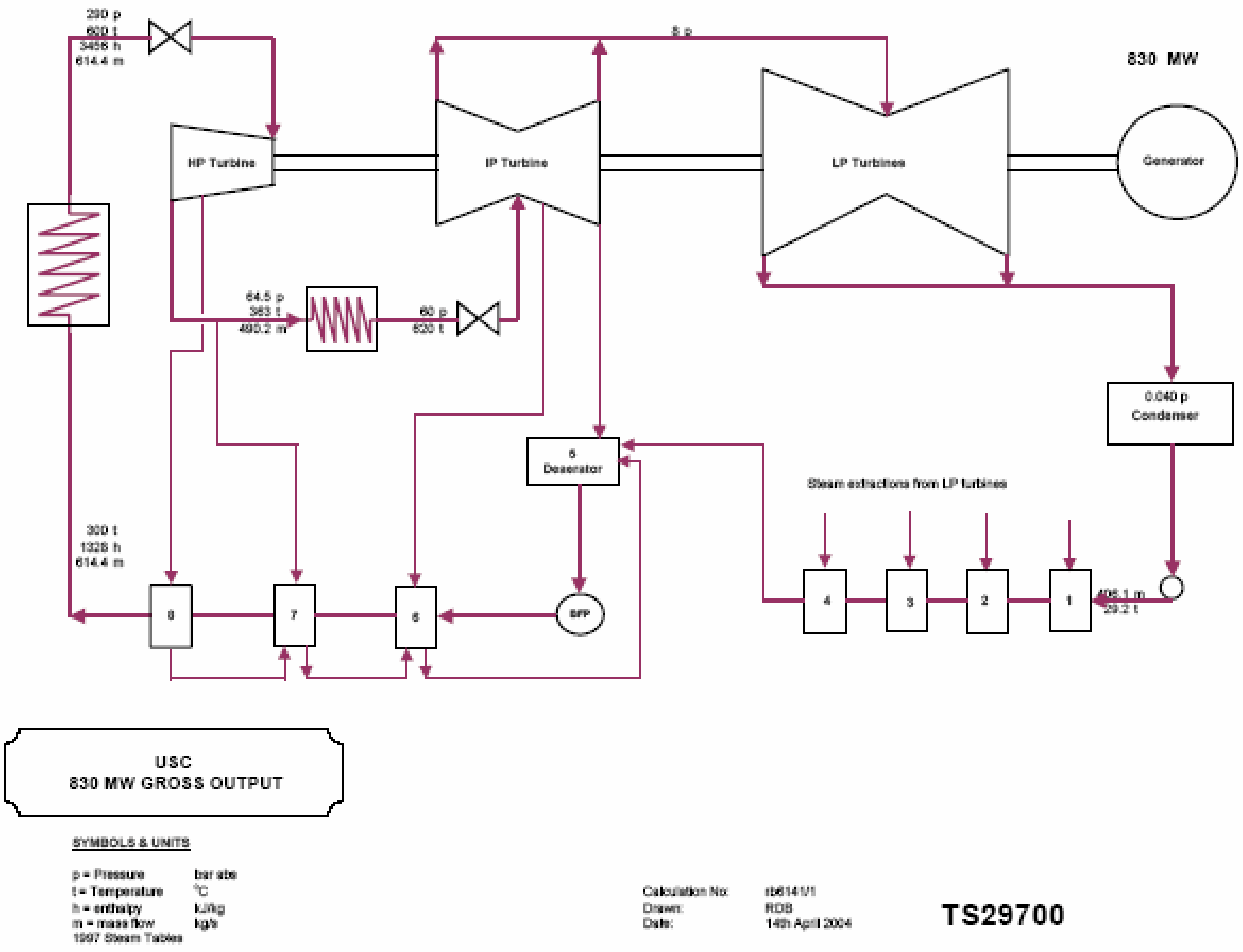


Drawing E5 Case2 Natural Gas Combined Cycle Power Plant with CO_2 Capture

CO_2 Compression System

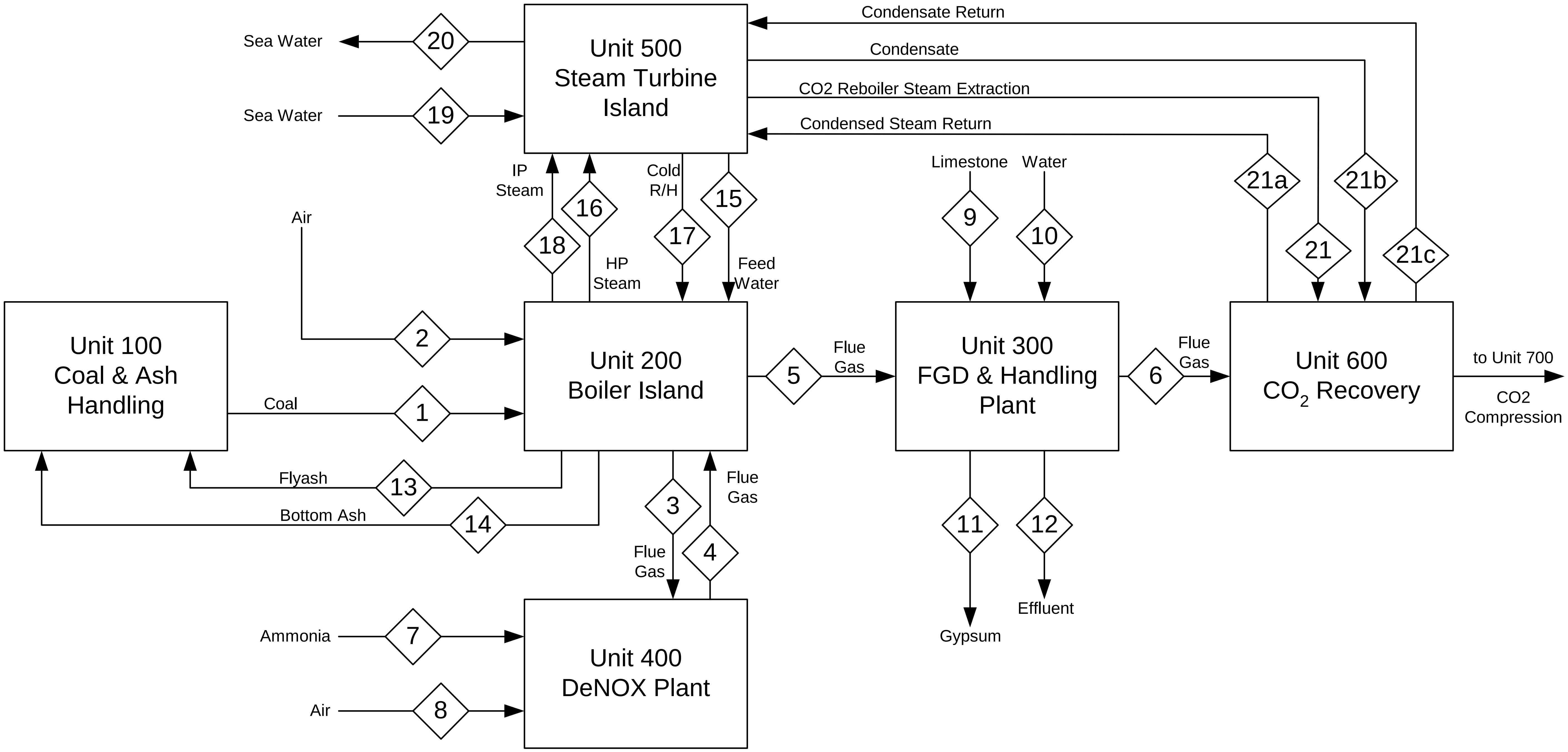
Case 3 830 MWe Gross PF Power Plant Base Case: Block Flow Diagram

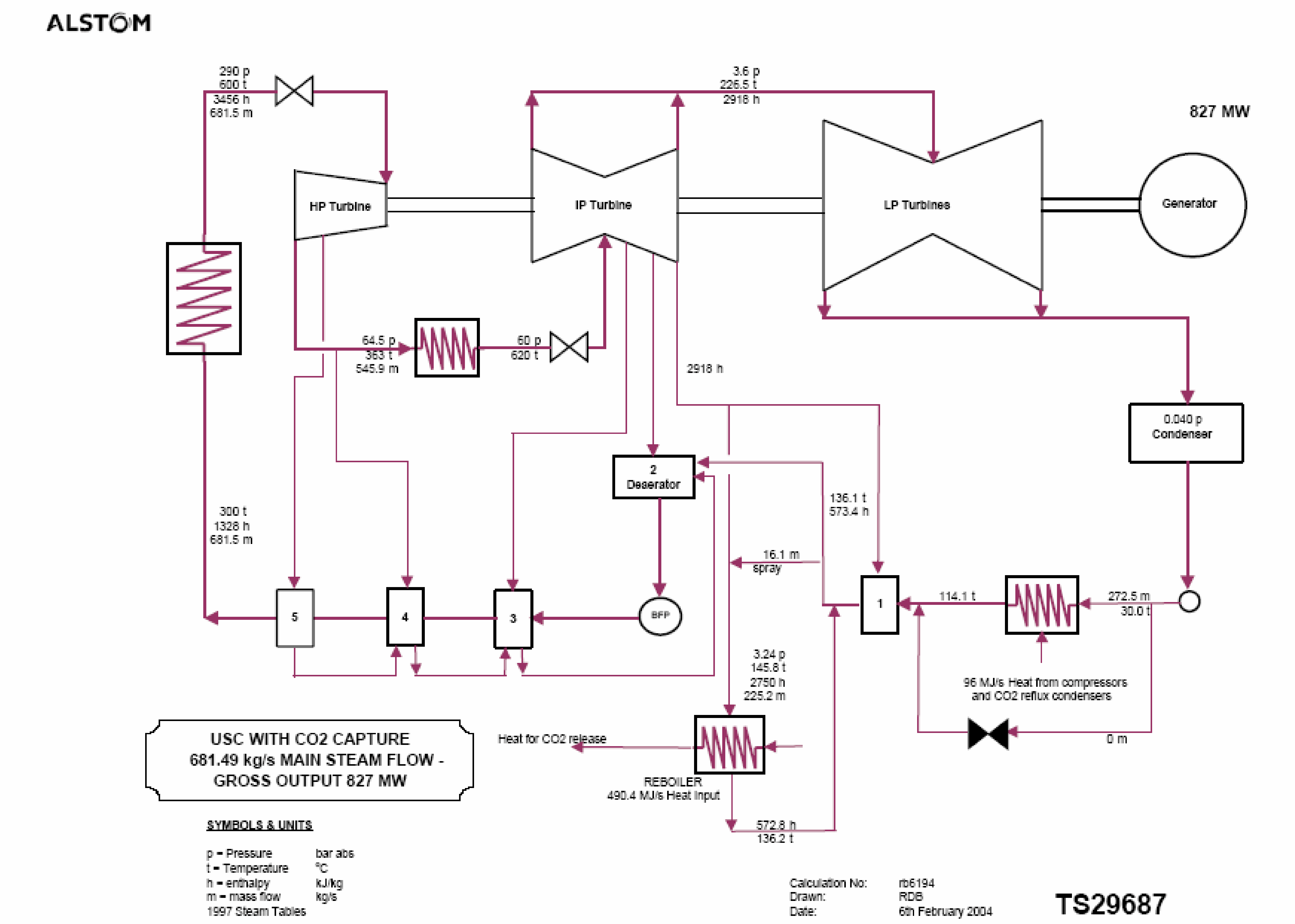




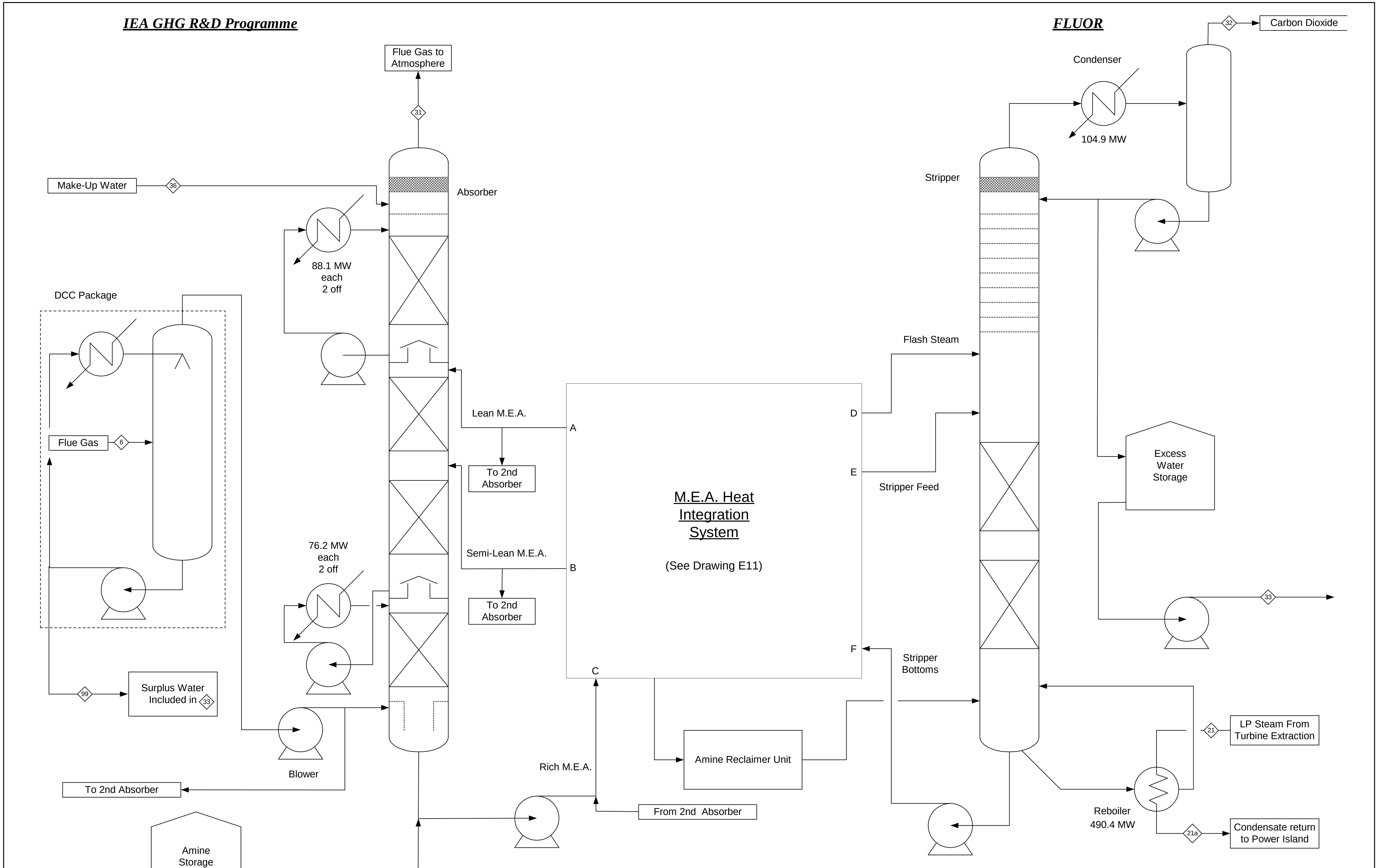
Drawing E7 *USCPF WITHOUT CAPTURE - TURBINE POWER ISLAND*

Case 4 827 MWe Gross PF Power Plant with CO_2 Capture Amine Scrubbing: Block Flow Diagram



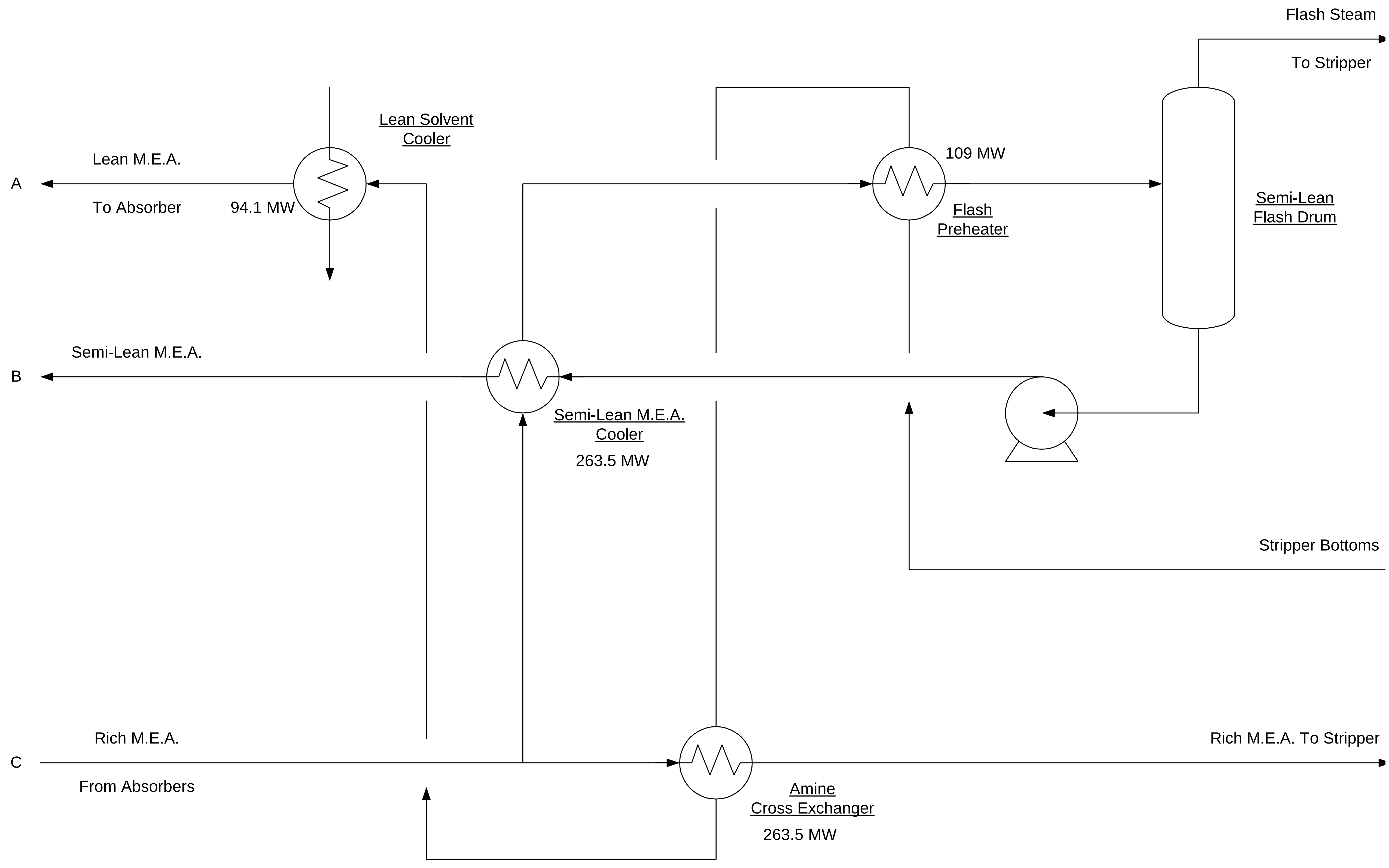


Drawing E9 *USCPF WITH CAPTURE - TURBINE POWER ISLAND*



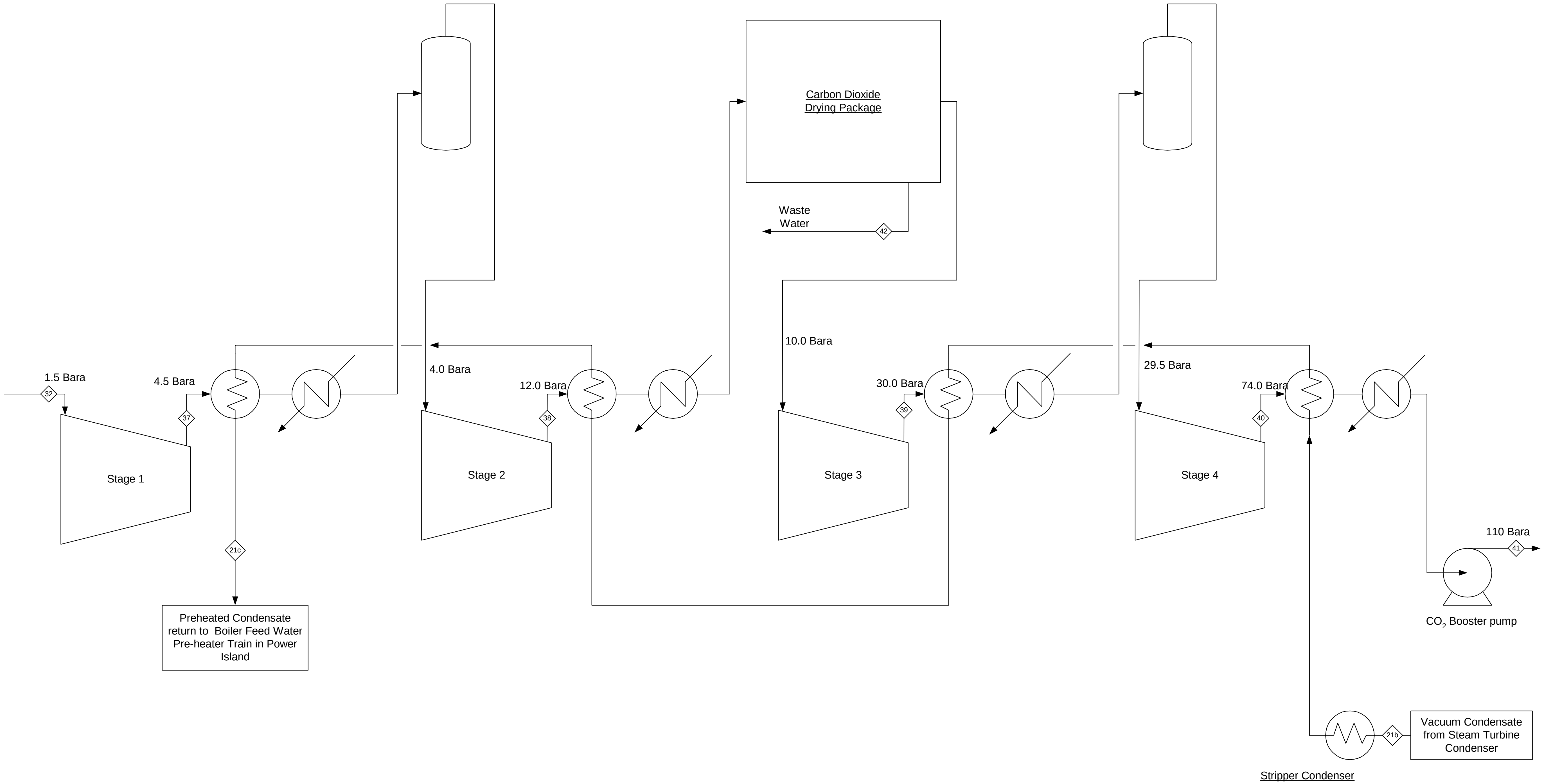
Drawing E10 Case4 Super-Critical Steam Cycle with CO_2 Capture

CO_2 Absorption and Amine Stripping



Drawing E11 Case4 Super-Critical Steam Cycle with CO_2 Capture

M.E.A. Heat Integration System



Drawing E12 Case 4 Super-Critical Steam Cycle with CO_2 Capture

CO_2 Compression and Recovery System

HEAT AND MATERIAL BALANCES

Index

Stream Description		HP steam from HRSG	HP steam to turbine	CRH Steam to turbine	CRH steam to HRSG	HRH Steam from HRSG	HRH Steam to turbine	IP Steam generation	LP steam addition	Total LP steam to turbine	Exhaust steam
Stream Number		1	2	3	4	5	6	7	8	9	10
Temperature Deg C		552	550	347.5	345	562	560	320	288	288	32.9
Pressure,Bara		127.5	125	31.85	30.33	28.35	27	30.33	5.29	5.29	0.05
Component Flows	MW										
H2O	18.02	284.58	569.16	556.2	275.4	319.93	639.86	44.53	73.66	726.48	725.76
CO2	44.01										
MEA	61.08										
N2	28.02										
O2	32										
Nat Gas											
Total kgmol/hr		15792.45	31584.91	30865.70	15283.02	17754.16	35508.32	2471.14	4087.68	40315.21	40275.25
Total Tonnes/hr		284.58	569.16	556.2	275.4	319.93	639.86	44.53	73.66	726.48	725.76
Molecular weight		18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02

NOTES

Component flows in Tons/Hr

SEE DWG E1

FLUOR

Heat And Material Balance
CASE: 1 NGCC NO CAPTURE

IEA-GHG
REV A
15/11/2004

Stream Description		Boiler feed water	Feed Water to HRSG	Water from heater	Water to heater	Water to HP/IP	LP steam Raised	Water to IP Econ	Water to IP Evap	Water to HP Econ	Blowdown
Stream Number		11	12	13	14	15	16	17	18	19	20
Temperature Deg C		32.9	32.9	104.4	231.6	158	158	160	231.6	163	100
Pressure,Bara		0.05	15.35	15.35	31.55	6	6	32.5	31.55	136	1.01
Component Flows	MW										
H2O	18.02	735.16	367.6	38.16	38.16	368.93	36.83	82.91	44.75	286.02	3.28
CO2	44.01										
MEA	61.08										
N2	28.02										
O2	32										
Nat Gas											
Total kgmol/hr		40796.89	20399.56	2117.647	2117.6471	20473.36	2043.84	4600.999	2483.352	15872.36	182.01998
Total Tonnes/hr		735.16	367.6	38.16	38.16	368.93	36.83	82.91	44.75	286.02	3.28
Molecular weight		18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02

NOTES

Component flows in Tons/Hr

SEE DWG E1

Approved by:

Stream Description			Losses	Make up BFW	Steam to vacuum system	Condensate from vac system	HP/IP Leakage	Fuel gas to GT	Flue Gas	Combustion air to GT
Stream Number			21	22	23	24	25	26	27	28
Temperature Deg C			Various	15	250	32.9	550	Ambient	101	9
Pressure,Bara			Various	3.45	30.33	0.05	125		1.01	1.1
Component Flows		MW								
	H_2O	18.02	0.72	4.28	5.4	5.15	7.56		235.17	
	CO_2	44.01							294.07	
	MEA	61.08								
Note 3	N_2	28.02							3534.83	
	O_2	32							669.34	
Note2	Nat Gas	19.35						107.19		
Note 4	AIR	28.89								4625.3
Total kgmol/hr								5539.57	166804	161264.43
Total Tonnes/hr			0.72	4.28	5.4	5.15	7.56	107.19	4732.53	4625.34
Molecular weight			18.02	18.02	18.02	18.02	18.02	19.35	28.37	28.68
Density,Kg/m3								0.863	0.92	1.24
								Note 1	**Note 1**	**Note 1**

NOTES

Component flows in Tons/Hr

1 These streams are total for both machines

2 Natural gas composition as per IEA tech spec

3 Nitrogen flows include argon

4 Mass balance closure achieved by balancing on air stream No 28 and adjustment of MW to appropriate value to achieve balance

SEE DWG E1

Stream Description		HP steam from HRSG	HP steam to turbine	CRH Steam to turbine	CRH steam to HRSG	HRH Steam from HRSG	HRH Steam to turbine	IP Steam generation	LP steam Extract	Total LP steam to turbine	Exhaust steam
Stream Number		1	2	3	4	5	6	7	8	9	10
Temperature Deg C		552	550	347.5	345	562	560	320	288	288	32.9
Pressure,Bara		127.5	125	31.85	30.33	28.35	27	30.33	5.29	5.29	0.05
Component Flows	MW										
H_2O	18.02	283.32	566.64	553.68	274.14	324.18	648.36	50.04	289	372.31	371.59
CO_2	44.01										
MEA	61.08										
N_2	28.02										
O_2	32										
Nat Gas											
Total kgmol/hr		15722.53	31445.06	30725.86	15213.10	17990.01	35980.02	2776.91	16037.74	20660.93	20620.98
Total Tonnes/hr		283.32	566.64	553.68	274.14	324.18	648.36	50.04	289	372.31	371.59
Molecular weight		18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02

NOTES

Component flows in Tons/Hr

SEE DWG E2

Stream Description		Boiler feed water	Feed Water to HRSG	Water from heater	Water to heater	Water to HP/IP	LP steam Raised	Water to IP Econ	Water to IP Evap	Water to HP Econ	Blowdown
Stream Number		11	12	13	14	15	16	17	18	19	20
Temperature Deg C		32.9	117	104.4	231.6	139	139	140	232	142	100
Pressure,Bara		0.05	15.35	1.8	31.55	3.5	3.5	32.5	31.55	136	1.01
Component Flows	MW										
H2O	18.02	371.59	436.72	76.32	38.16	393.34	43.38	88.45	50.29	304.88	3.35
CO2	44.01										
MEA	61.08										
N2	28.02										
O2	32										
Nat Gas											
Total kgmol/hr		20620.98	24235.29	4235.294	2117.647	21827.97	2407.325	4908.435	2790.788	16918.98	185.9046
Total Tonnes/hr		371.59	436.72	76.32	38.16	393.34	43.38	88.45	50.29	304.88	3.35
Molecular weight		18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02

NOTES

Component flows in Tons/Hr

SEE DWG E2

Stream Description			Losses	Make up BFW	Steam to vacuum system	Condensate from vac system	HP/IP Leakage	Steam to amine unit	Condensate from amine unit	Desuperheater Water	Fuel gas to GT	Flue Gas	Combustion air to GT
Stream Number			21	22	23	24	25	26	27	28	29	30	30a
Temperature Deg C			Various	15	250	32.9	550	136	136	142	Ambient	101	9
Pressure,Bara			Various	3.45	30.33	0.05	125	3.24	3.24	136		1.01	1.1
Component Flows		MW											
	H2O	18.02	0.72	9.5	5.4	5.15	7.56	416.09	416.09	20.16		235.17	
	CO2	44.01										294.07	
	MEA	61.08											
Note 3	N2	28.02										3534.83	
	O2	32										669.34	
Note2	Nat Gas	19.35									107.19		
Note 4	AIR	28.89											
Total kgmol/hr											5539.57	166804	161264.43
Total Tonnes/hr			0.72	9.5	5.4	5.15	7.56	416.09	416.09	20.16	107.19	4732.53	4625.34
Molecular weight			18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	19.35	28.37	28.68
Density,Kg/m3											0.863	0.92	1.24
											Note 1	**Note 1**	**Note 1**

NOTES

Component flows in Tons/Hr

1. These streams are total for both machines
2. Natural gas composition as per IEA tech spec
3. Nitrogen flows include argon
4. Mass balance closure achieved by balancing on air stream No 28 and adjustment of MW to appropriate value to achieve balance

SEE DWG E2

FLUOR

Heat And Material Balance
CASE 2: NGCC WITH CAPTURE

IEA-GHG
REV A
15/11/2004

Stream Description			Flue Gas to DCC	Flue Gas to Atmos	CO2 From Stripper	Surplus Water	LP Steam to Reboiler	Cond Return to Power Island	Make Up Water
Stream Number			30	31	32	33	34	35	36
Temperature Deg C			101	55.5	37.8	37.8	136	136	37.8
Pressure,Bara			1.01	1.12	1.48	2.76	3.24	3.24	1.38
Component Flows		MW							
	H2O	18.02	13051	16521	267	3352	23090	23090	7275
	CO2	44.01	6682	984	5690				
	MEA	61.08							
Note 3	N2	28.02	126154	126153	1				
	O2	32	20917	20917					
Note2	Nat Gas	19.35							
Note 4	AIR	28.89							
Total kgmol/hr			166804	164574	5958	3352	23090	23090	7275
Total Tonnes/hr			4732.53	4544.25	255.107	64.34	416.09	416.09	131.09
Molecular weight			28.37	27.61	42.82	18.02	18.02	18.02	18.02
Density,Kg/m3			0.92	1.06	2.47	0.99		0.98	0.99
				Note 2	**Note 3**				**Note1**

NOTES

component flows in Kgmol/Hr

1 Flows for a total of three streams, one to each of three absorbers
2 Flows for three absorbers discharging to atmosphere
3 CO2 recovered is 85% of inlet CO2 in stream 30

SEE DWG E 3

Stream Description			Ist Stg Compressor Discharge	2nd Stg Compressor Discharge	3rd Stg Compressor Discharge	4th Stg Compressor Discharge	Product CO2	Waste Water
Stream Number			37	38	39	40	41	42
Temperature Deg C			182	184	187	164	107	
Pressure,Bara			4.5	12	30	74	110	
Component Flows		MW	**Note 2**	**Note 2**	**Note 2**	**Note 2**		
	H2O	18.02	267				Trace	267
	CO2	44.01	5690				5690	
	MEA	61.08						
Note 3	N2	28.02	1					
	O2	32						
Note2	Nat Gas	19.35						
Note 4	AIR	28.89						
Total kgmol/hr			5958				5690	267
Total Tonnes/hr			255.107				250.41	4.81
Molecular weight			42.82				44.01	18.02
Density,Kg/m3								
							6010 TPD	**Note 1**

NOTES

Component Flows in Kgmol/Hr

1 Interstage water knock out reported in total of stream 42
2 Compressor pressure profile is : In/Out stg 1:- 1.5/4.5 Bara;stg 2:-4/12 Bara;stg 3:-10/30 Bara; stg 4:-29.5/74 Bara
intermediate stream water contents not shown but correspond to saturation at 37.8 deg C for 1st two stages.

SEE DWG E5

HEAT AND MATERIAL BALANCES FOR CASE 3 AND CASE 4

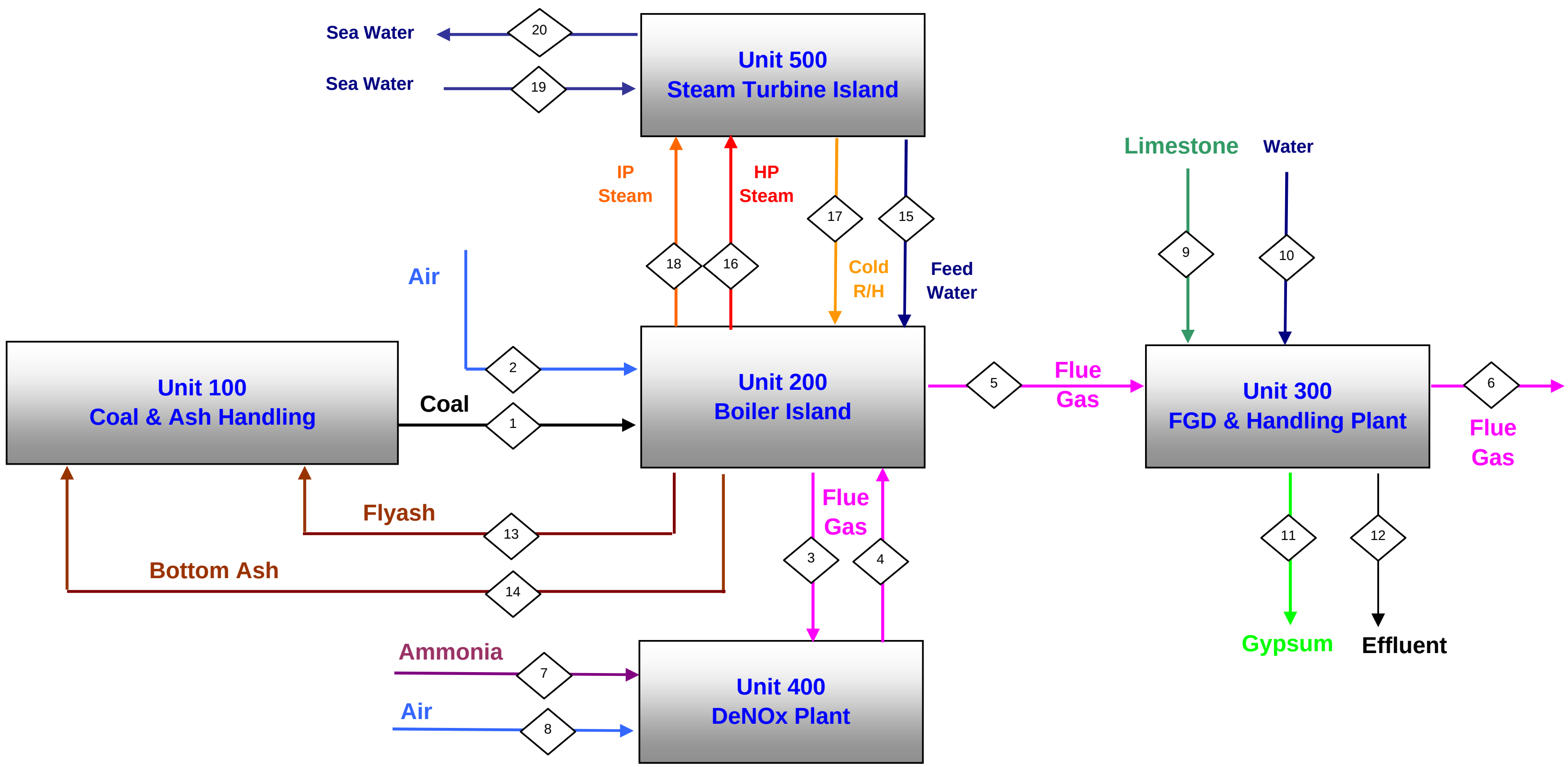
The following tables present Mitsui Babcock mass balance data for the boiler island and for the Alstom power island

Amine capture plant and CO2 compression for case 4 follows the above data

Ultra-supercritical / CO2 Capture study
BOILER/PROCESS INTERFACE DATA

		24/12/2003	06/02/2004
		831 MW	**827 MW**
		No CO2 Capture	CO2 Capture
Generator gross output	MW	831	827
HP turbine inlet steam pressure	bara	290	290
HP turbine inlet steam temperature	^oC	600	600
HP turbine inlet steam flow	kg/h	2211816	2453365
	kg/s	614.393	681.4903
HP exhaust steam pressure	bara	64.5	64.5
HP exhaust steam temperature	^oC	363	363
Steam flow to reheater	kg/h	1764749	1965160
Reheater spraywater flow	kg/h	0	0
	kg/s	490.208	545.878
IP turbine inlet steam pressure	bara	60	60
IP turbine inlet steam temperature	^oC	620	620
CW inlet temperature	^oC	12	12
Condenser pressure	mbar	40	40
Final feedwater presssure	bara	325	325
Final feedwater temperature	^oC	300	300
Heat to cycle from compressors etc	MJ/s	0	96
Steam Heat to Reboiler	MJ/s	0	490.4
Turbine Island Aux power	MW	33.5	37
te pump motors, CW pump motors, turbine aux. - approx. only)			
ALSTOM calc. Ref		rb6141/1	rb6194/1
ALSTOM Drawing No.		TS29700	TS29687
1997 Steam Tables			
RDB revised 06/2/2004			

Case 3 : 830 MWe Gross PF Power Plant Base Case : Block Flow Diagram



18 2 24-(7+8) 24 28

Stream ID		1	2	3	4	5	6	7	8	9	10
Material		Coal	Air	Gas	Gas	Gas	Gas	Ammonia	Air	Limestone	Water
Mass Flow Rate											
- Coal	kg/s	66.61	0	0.29	0.29	0	0	0	0	0	0
- Air	kg/s	0	752.3	0	0	0	0	0	2.24	0	0
- Flue Gas	kg/s	0	0	773.9	776.3	812.6	825.9	0	0	0	0
- Ash	kg/s	0	0	5.3	5.3	0.018	0.009	0	0	0	0
- Water	kg/s	0	0	0	0	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	0	0	0	0	0
- Ammonia	kg/s	0	0	0	0	0	0	0.117	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	1.77	0
Volume Flowrate	Am^3/s	-	607.9	1403.9	1407.8	874.3	838.5	-	1.84	-	0.013
	Nm^3/s	-	587.0	586.6	588.4	617.3	639.6	0.151	1.74	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Temperature	°C	9	9	380	380	114	85	9	15	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.24	0.55	0.55	0.93	0.98	-	1.21	-	-
Composition											
O_2	%v/v,wet		20.6	3.3	3.3	4.55	4.33		20.6		
CO_2	%v/v,wet		0.0	13.94	13.94	12.93	12.38		0.0		
SO_2	%v/v,wet		0.0	0.07	0.07	0.06	0.01		0.0		
H_2O	%v/v,wet		1.9	8.86	8.86	8.35	12.21		1.9		
N_2	%v/v,wet		77.5	73.83	73.83	74.1	71.07		77.5		
Emissions @ 6%O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1896	1896	1751	201				
CO	mg/Nm^3			0	0	0	0				
Particulates	mg/Nm^3			8529	8503	30	14				
				54, 56	55						

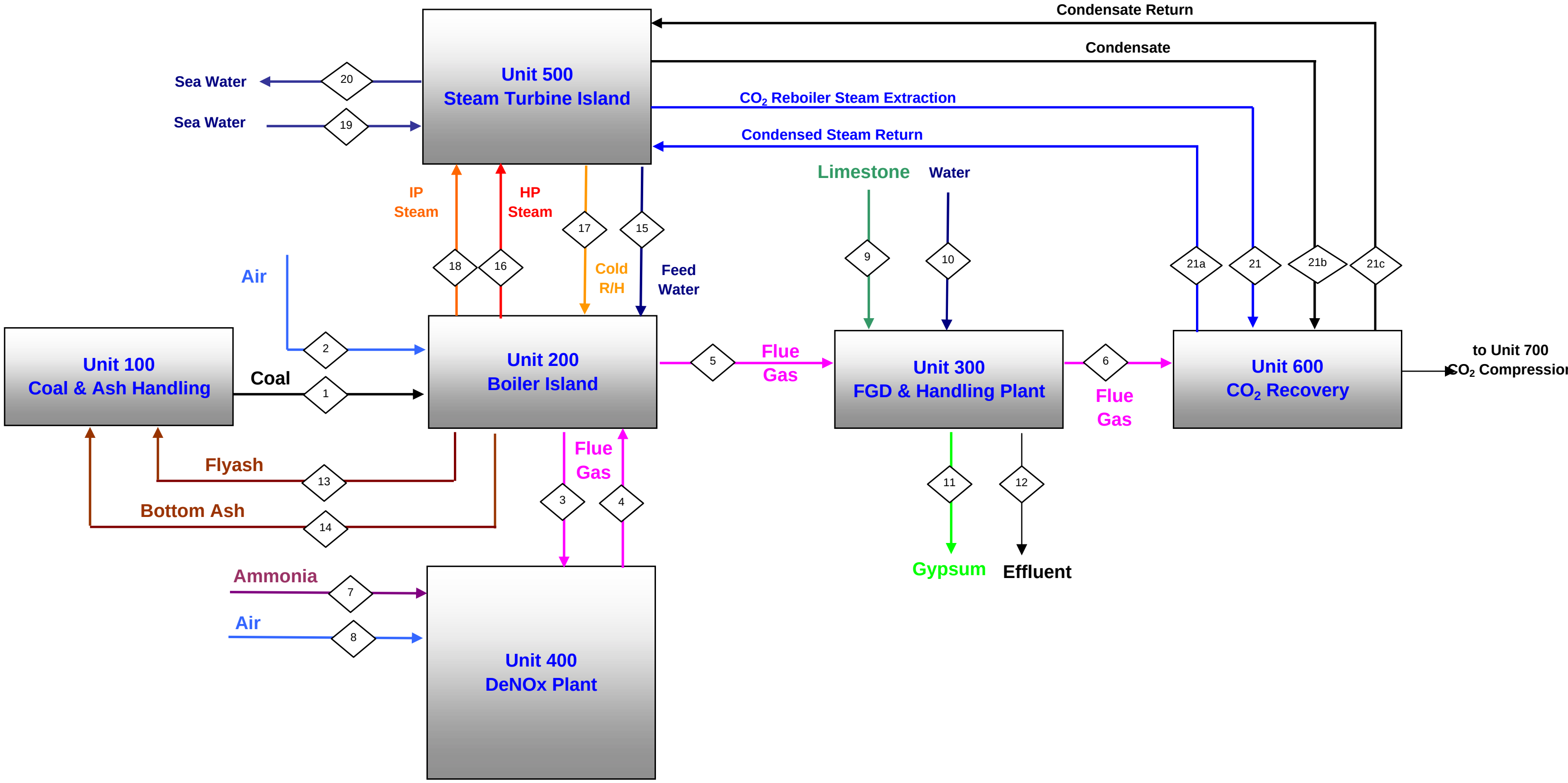
Stream ID		11	12	13	14	15	16	17	18	19	20
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water
Mass Flow Rate											
- Coal	kg/s	0	0	0.34	0.11	0	0	0	0	0	0
- Air	kg/s	0	0	0	0	0	0	0	0	0	0
- Flue Gas	kg/s	0	0	0	0	0	0	0	0	0	0
- Ash	kg/s	0	0	6.08	2.03	0	0	0	0	0	0
- Water	kg/s	0.31	0.17	0	0	614.4	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	614.4	490.2	490.2	0	0
- Ammonia	kg/s	0	0	0	0	0	0	0	0	0	0
- Limestone	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	2.91	0	0	0	0	0	0	0	0	0
Volume Flowrate	Am^3/s	-	-	-	-	-	-	-	-	28.1	28.1
	Nm^3/s	-	-	-	-	-	-	-	-	-	-
Props											
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid
- Temperature	°C	0	23	114 / 380	1000	300	600	363	620	#REF!	19
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	-
Composition											
O_2	%v/v,wet										
CO_2	%v/v,wet										
SO_2	%v/v,wet										
H_2O	%v/v,wet										
N_2	%v/v,wet										
Emissions @ 6%O_2 Dry											
NOx	mg/Nm^3										
SOx	mg/Nm^3										
CO	mg/Nm^3										
Particulates	mg/Nm^3										

Model ID: IEA Amine
Load ID: Case 3

Stream ID	Description	Temperature C	Gas mass flow kg/s	Wet Fuel mass flow kg/s	Ash mass flow kg/s	Gas vol flow NTP m3/s	Gas vol flow actual m3/s	Inlet pressure kPa g	Outlet pressure kPa g	Enthalpy kJ/kg	Gas specific volume m3/kg
0	SAH bypass inlet	9	0	0	0	0	0	0	0	12.95	0.808
1	SAH Bypass air	9	0	0	0	0	0	0	0	12.95	0.808
2	SAH Air inlet	9	746.194	0	0	583.201	602.816	0	0	12.95	0.808
3	SAH outlet	9.5	746.194	0	0	583.201	603.908	0	0	13.46	0.809
4	FD fan inlet	9.5	746.194	0	0	583.201	603.908	0	0	13.46	0.809
5	FD fan outlet	14.5	746.194	0	0	583.201	614.591	0	0	18.46	0.824
6	GAH sec air inlet	14.5	593.318	0	0	463.719	488.678	0	0	18.46	0.824
7	GAH sec air outlet	341	573.016	0	0	447.851	1007.618	0	0	358.5	1.758
8	Sec air to windbox	341	456.769	0	0	356.996	803.204	0	0	358.5	1.758
9	Sec air to AA port	341	116.247	0	0	90.855	204.414	0	0	358.5	1.758
09a	Sec air to AA port	341	116.247	0	0	90.855	204.414	0	0	358.5	1.758
10	PA fan inlet	14.5	152.875	0	0	119.482	125.913	0	0	18.46	0.824
10a	PA fan outlet	22.5	152.875	0	0	119.482	129.415	0	0	26.47	0.847
11	GAH prim air inlet	22.5	116.77	0	0	91.264	98.851	0	0	26.47	0.847
12	GAH prim air outlet	326	90.497	0	0	70.729	155.247	0	0	342.31	1.715
13	Mill air inlet	259.9	116.602	0	0	91.132	177.962	0	0	271.6	1.526
14	PA to tempering air	22.5	36.105	0	0	28.219	30.565	0	0	26.47	0.847
15	Seal air fan inlet	22.5	10	0	0	7.816	8.465	0	0	26.47	0.847
15a	Seal air fan outlet	22.5	10	0	0	7.816	8.465	0	0	26.47	0.847
16	Tempering air	22.5	26.105	0	0	20.403	22.099	0	0	26.47	0.847
16a	Tempering air	22.5	26.105	0	0	20.403	22.099	0	0	26.47	0.847
18	Coal inlet	9	0	66.61	0	0	0	0	0	-21.52	0
20	Coal/air to burners	90	121.664	61.548	0	97.431	129.619	0	0	155.35	1.065
23	LP air inlet	9	6	0	0	4.689	4.847	0	0	12.95	0.808
23a	Burner core air	17	6	0	0	4.689	4.985	0	0	20.95	0.831
24	Flue gas to GAH	380	776.263	0.291	5.283	588.406	1407.848	0	0	515.57	1.814
25	GAH gas outlet	115	822.838	0.292	5.283	624.805	888.377	0	0	218.16	1.08
26	PRCP to ID	113.5	835.181	0	0.018	634.451	898.614	0	0	216.16	1.076
27	J8 to Damper	113.5	812.572	0	0.018	617.276	874.288	0	0	216.16	1.076
28	Flue Gas Outlet	113.5	812.572	0	0.018	617.276	874.288	0	0	216.16	1.076
30	Gas recycling inlet	113.5	22.609	0	0	17.175	24.326	0	0	216.16	1.076
30a	Gas recycling outlet	113.5	22.609	0	0	17.175	24.326	0	0	216.16	1.076
31	Precip gas outlet	113.5	835.181	0	0.018	634.451	898.614	0	0	216.16	1.076
54	Precip ash outlet	113.5	0	0.29	5.264	0	0	0	0	63.33	0
55	Hopper ash outlet	1000	0	0.112	2.032	0	0	0	0	940.45	0
56	Boiler ash outlet	380	0	0.045	0.813	0	0	0	0	280.6	0
97	Furnace infiltration	9	-0.001	0	0	-0.001	-0.001	0	0	12.95	0.808
98	Mill seal air outlet	22.5	10	0	0	7.816	8.465	0	0	26.47	0.847
99	Precip air infilt	9	12.343	0	0	9.647	9.971	0	0	12.95	0.808

Stream ID	Gas specific heat kJ/kg C	Gas conductivity W/m C	Gas viscosity Pas	O2 weight wet %	CO2 weight wet %	SO2 weight wet %	H2O weight wet %	N2 weight wet %	O2 volume wet %	CO2 volume wet %	SO2 volume wet %	H2O volume wet %	N2 volume wet %
0	0.998	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
1	0.998	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
2	0.998	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
3	0.998	0.021	13.9	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
4	0.998	0.021	13.9	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
5	1	0.021	14.26	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
6	1	0.021	14.26	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
7	1.081	0.042	28.82	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
8	1.081	0.042	28.82	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
9	1.081	0.042	28.82	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
09a	1.081	0.042	28.82	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
10	1	0.021	14.26	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
10a	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
11	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
12	1.077	0.041	28.35	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
13	1.062	0.037	26.16	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
14	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
15	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
15a	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
16	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
16a	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
18	1.345	0	0	0	0	0	0	0	0	0	0	0	0
20	1.074	0.026	18.91	21.91	0.05	0	5.3	72.74	19.22	0.03	0	8.26	72.49
23	0.998	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
23a	1.001	0.021	14.43	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
24	1.143	0.045	30.01	3.57	20.7	0.15	5.39	70.19	3.3	13.94	0.07	8.86	73.83
25	1.053	0.028	20.21	4.66	19.53	0.14	5.15	70.51	4.31	13.13	0.07	8.45	74.04
26	1.055	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
27	1.055	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
28	1.055	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
30	1.055	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
30a	1.055	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
31	1.055	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
54	0.74	0	0	0	0	0	0	0	0	0	0	0	0
55	1.238	0	0	0	0	0	0	0	0	0	0	0	0
56	0.89	0	0	0	0	0	0	0	0	0	0	0	0
97	0.998	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
98	1.002	0.022	14.81	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
99	0.998	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52

Case 4 : 827 MWe Gross PF Power Plant with CO2 Capture Amine Scrubbing : Block Flow Diagram



		18	2	24-(7+8)	24	28					
Stream ID		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Material		Coal	Air	Gas	Gas	Gas	Gas	Ammonia	Air	Limestone	Water
Mass Flow Rate											
- Coal	kg/s	73.96	0	0.32	0.32	0	0	0	0	0	0
- Air	kg/s	0	835.2	0	0	0	0	0	2.48	0	0
- Flue Ga	kg/s	0	0	859.3	861.9	902.2	930.6	0	0	0	0
- Ash	kg/s	0	0	5.9	5.9	0.02	0.009	0	0	0	0
- Water	kg/s	0	0	0	0	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	0	0	0	0	0
- Ammoni	kg/s	0	0	0	0	0	0	0.129	0	0	0
- Limesto	kg/s	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	0	0	0	0	0	0	0	0	2.15	0
Volume Flo	Am^3/s	-	674.9	1558.8	1563.3	970.8	855.2	-	2.04	-	0.028
	Nm^3/s	-	653.1	651.4	653.3	685.4	720.7	0.168	1.93	-	-
Props											
- Phase		Solid	Gas	Gas	Gas	Gas	Gas	Liquid	Gas	Solid	Liquid
- Tempera	°C	9	9	380	380	114	51	9	14	-	-
- Pressure	barg	-	-	-	-	-	-	10.0	-	-	-
- Density	kg/m^3	-	1.24	0.55	0.55	0.93	1.09	-	1.22	-	-
Composition											
O_2	%v/v,wet		20.56	3.30	3.30	4.55	4.33		20.56		
CO_2	%v/v,wet		0.03	13.94	13.94	12.93	12.38		0.03		
SO_2	%v/v,wet		0.00	0.07	0.07	0.06	0.00		0.00		
H_2O	%v/v,wet		1.89	8.86	8.86	8.35	12.21		1.89		
N_2	%v/v,wet		77.52	73.83	73.83	74.10	71.08		77.52		
Emissions @ 6% O_2 Dry											
NOx	mg/Nm^3			650	200	200	200				
SOx	mg/Nm^3			1896	1896	1751	29				
CO	mg/Nm^3			0	0	0	0				
Particulat	mg/Nm^3			8529	8503	30	14				

				54, 56	55										
Stream ID		**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**21a**	**21b**	**21c**
Material		Gypsum	Effluent	Flyash	Coarse Ash	Feed Water	HP Steam	R/H Steam	IP Steam	Sea Water	Sea Water	Steam	Sat. Water	Condensate	Condensate
Mass Flow Rate															
- Coal	kg/s	0	0	0.37	0.12	0	0	0	0	0	0	0	0	0	0
- Air	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Flue Ga	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Ash	kg/s	0	0	6.75	2.26	0	0	0	0	0	0	0	0	0	0
- Water	kg/s	0.37	0.17	0	0	681.5	0	0	0	0	0	0	0	0	0
- Steam	kg/s	0	0	0	0	0	681.5	545.9	545.9	0	0	225.2	225.2	272.5	272.5
- Ammoni	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Limesto	kg/s	0	0	0	0	0	0	0	0	0	0	0	0	0	0
- Gypsum	kg/s	3.54	0	0	0	0	0	0	0	0	0	0	0	0	0
Volume Flo	Am^3/s	-	-	-	-	-	-	-	-	20.6	20.6	-	-	-	-
	Nm^3/s	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Props															
- Phase		Solid	Liquid	Gas	Solid	Liquid	Gas	Gas	Gas	Liquid	Liquid	Gas	Liquid	Liquid	Liquid
- Tempera	°C	-	-	114 / 380	1000	300	600	363	620	12	19	146	136	30	114
- Pressure	barg	-	-	-	-	324.0	289.0	63.5	59.0	-	-	2.24	2.24	-	-
- Density	kg/m^3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Composition															
O_2	%v/v,wet														
CO_2	%v/v,wet														
SO_2	%v/v,wet														
H_2O	%v/v,wet														
N_2	%v/v,wet														
Emissions @ 6% O_2 Dry															
NOx	mg/Nm^3														
SOx	mg/Nm^3														
CO	mg/Nm^3														
Particulat	mg/Nm^3														

Model ID: IEA Amine
Load ID: Case 4c

Stream ID	Description	Temperature	Gas mass flow	Fuel mass	Ash mass flow	Gas vol flow NTP	Gas vol flow actual	Inlet pressure	Outlet pressure	Enthalpy	s specific volu	Gas specific heat
		C	kg/s	kg/s	kg/s	m3/s	m3/s	kPa g	kPa g	kJ/kg	m3/kg	kJ/kg C
0	SAH bypass inlet	9	0	0	0	0	0	0	0	12.95	0.808	0.998
1	SAH Bypass air	9	0	0	0	0	0	0	0	12.95	0.808	0.998
2	SAH Air inlet	9	828.022	0	0	647.155	668.921	0	0	12.95	0.808	0.998
3	SAH outlet	8.9	828.022	0	0	647.155	668.716	0	0	12.86	0.808	0.998
4	FD fan inlet	8.9	828.022	0	0	647.155	668.716	0	0	12.86	0.808	0.998
5	FD fan outlet	13.9	828.022	0	0	647.155	680.57	0	0	17.86	0.822	1
6	GAH sec air inlet	13.9	659.27	0	0	515.264	541.869	0	0	17.86	0.822	1
7	GAH sec air outlet	340	636.842	0	0	497.735	1118.03	0	0	357.42	1.756	1.081
8	Sec air to windbox	340	507.836	0	0	396.909	891.549	0	0	357.42	1.756	1.081
9	Sec air to AA port	340	129.006	0	0	100.827	226.481	0	0	357.42	1.756	1.081
09a	Sec air to AA port	340	129.006	0	0	100.827	226.481	0	0	357.42	1.756	1.081
10	PA fan inlet	13.9	168.752	0	0	131.891	138.701	0	0	17.86	0.822	1
10a	PA fan outlet	21.9	168.752	0	0	131.891	142.567	0	0	25.87	0.845	1.002
11	GAH prim air inlet	21.9	130.168	0	0	101.735	109.97	0	0	25.87	0.845	1.002
12	GAH prim air outlet	325	100.88	0	0	78.845	172.771	0	0	341.24	1.713	1.077
13	Mill air inlet	259.9	129.465	0	0	101.185	197.596	0	0	271.61	1.526	1.062
14	PA to tempering air	21.9	38.584	0	0	30.156	32.597	0	0	25.87	0.845	1.002
15	Seal air fan inlet	21.9	10	0	0	7.816	8.448	0	0	25.87	0.845	1.002
15a	Seal air fan outlet	21.9	10	0	0	7.816	8.448	0	0	25.87	0.845	1.002
16	Tempering air	21.9	28.584	0	0	22.341	24.149	0	0	25.87	0.845	1.002
16a	Tempering air	21.9	28.584	0	0	22.341	24.149	0	0	25.87	0.845	1.002
18	Coal inlet	9	0	73.96	0	0	0	0	0	-21.52	0	1.345
20	Coal/air to burners	90	135.085	68.339	0	108.179	143.918	0	0	155.35	1.065	1.074
23	LP air inlet	9	6	0	0	4.689	4.847	0	0	12.95	0.808	0.998
23a	Burner core air	17	6	0	0	4.689	4.985	0	0	20.95	0.831	1.001
24	Flue gas to GAH	380	861.917	0.324	5.866	653.332	1563.272	0	0	515.61	1.814	1.143
25	GAH gas outlet	115	913.632	0.324	5.866	693.748	986.48	0	0	218.2	1.08	1.053
26	PRCP to ID	113.5	927.337	0	0.02	704.458	997.847	0	0	216.19	1.076	1.055
27	J8 to Damper	113.5	902.233	0	0.02	685.388	970.835	0	0	216.19	1.076	1.055
28	Flue Gas Outlet	113.5	902.233	0	0.02	685.388	970.835	0	0	216.19	1.076	1.055
30	Gas recycling inlet	113.5	25.104	0	0.001	19.07	27.013	0	0	216.19	1.076	1.055
30a	Gas recycling outlet	113.5	25.104	0	0.001	19.07	27.013	0	0	216.19	1.076	1.055
31	Precip gas outlet	113.5	927.337	0	0.02	704.458	997.847	0	0	216.19	1.076	1.055
54	Precip ash outlet	113.5	0	0.322	5.845	0	0	0	0	63.33	0	0.74
55	Hopper ash outlet	1000	0	0.124	2.256	0	0	0	0	940.45	0	1.238
56	Boiler ash outlet	380	0	0.05	0.902	0	0	0	0	280.6	0	0.89
97	Furnace infiltration	9	0.066	0	0	0.052	0.053	0	0	12.95	0.808	0.998
98	Mill seal air outlet	21.9	10	0	0	7.816	8.448	0	0	25.87	0.845	1.002
99	Precip air infilt	9	13.704	0	0	10.711	11.071	0	0	12.95	0.808	0.998

Stream ID	Gas conductivity	Gas viscosity	O_2 weight wet	CO_2 weight wet	SO_2 weight wet	H_2O weight wet	N_2 weight wet	O_2 volume wet	CO_2 volume wet	SO_2 volume wet	H_2O volume wet	N_2 volume wet
	W/m C	Pas	%	%	%	%	%	%	%	%	%	%
0	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
1	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
2	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
3	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
4	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
5	0.021	14.22	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
6	0.021	14.22	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
7	0.042	28.79	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
8	0.042	28.79	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
9	0.042	28.79	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
09a	0.042	28.79	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
10	0.021	14.22	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
10a	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
11	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
12	0.041	28.32	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
13	0.037	26.16	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
14	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
15	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
15a	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
16	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
16a	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
18	0	0	0	0	0	0	0	0	0	0	0	0
20	0.026	18.91	21.91	0.05	0	5.3	72.74	19.22	0.03	0	8.26	72.49
23	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
23a	0.021	14.43	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
24	0.045	30.01	3.57	20.7	0.15	5.39	70.19	3.3	13.94	0.07	8.86	73.83
25	0.028	20.21	4.66	19.53	0.14	5.15	70.51	4.31	13.13	0.07	8.45	74.04
26	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
27	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
28	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
30	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
30a	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
31	0.028	20.13	4.93	19.25	0.14	5.09	70.59	4.55	12.93	0.06	8.35	74.1
54	0	0	0	0	0	0	0	0	0	0	0	0
55	0	0	0	0	0	0	0	0	0	0	0	0
56	0	0	0	0	0	0	0	0	0	0	0	0
97	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
98	0.022	14.77	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52
99	0.021	13.86	22.87	0.05	0	1.19	75.9	20.56	0.03	0	1.89	77.52

Stream Description			Flue Gas to DCC	Flue Gas to Atmos	CO2 From Stripper	Surplus Water	LP Steam to Reboiler	Cond Return to Power Island	Make Up Water
Stream Number			6	31	32	33	21	21a	36
Temperature Deg C			50	46.1	37.8	37.8	136	136	37.8
Pressure,Bara			1.01	1.01	1.62	2.76	3.24	3.24	1.38
Component Flows		MW							
	H2O	18.02	9465	10328	533	6293	44990	44990	7688
	CO2	44.01	14597	2160	12425	12			
	MEA	61.08				9			
Note 3	N2	28.02	84161	84160	1				
	O2	32	5816	5816					
Note2	Nat Gas	19.35							
Note 4	AIR	28.89							
Total kgmol/hr			114039	102464	12959	6314	44990	44990	7688
Total Tonnes/hr			3356.7	1412.43	556.43	114.395	810.72	810.72	138.5
Molecular weight			29.43	27.57	42.94	18.12	18.02	18.02	18.02
Density,Kg/m3			1.111	1.05	2.71	0.99		0.99	0.99
			Note 4	**Note 2**	**Note 3**				**Note1**

NOTES

component flows in Kgmol/Hr

1 Flows for a total of two streams
2 Flows for two absorbers discharging to atmosphere
3 CO2 recovered is 85% of inlet CO2 in stream 6
4 This stream matches is a match stream for stream 6 on boiler island mass balance table

SEE DWG E10

Stream Description			Ist Stg Compressor Discharge	2nd Stg Compressor Discharge	3rd Stg Compressor Discharge	4th Stg Compressor Discharge	Turbine condensate from power plant	Turbine Condensate to power plant	Product CO2	Waste Water
Stream Number			37	38	39	40	21b	21c	41	42
Temperature Deg C			182	184	187	164	30	114	107	
Pressure,Bara			4.5	12	30	74	1 bar	hold	110	
Component Flows		MW	**Note 2**	**Note 2**	**Note 2**	**Note 2**	**Note 3**	**Note 3**		
	H2O	18.02	533						Trace	533
	CO2	44.01	12425						12425	
	MEA	61.08								
Note 3	N2	28.02	1							
	O2	32								
Note2	Nat Gas	19.35								
Note 4	AIR	28.89								
Total kgmol/hr			12959						12425	533
Total Tonnes/hr			556.426				989	989	546.8	9.59
Molecular weight			42.94						44.01	18.02
Density,Kg/m3							1000	1000		
									13123TPD	**Note 1**

NOTES

Component Flows in Kgmol/Hr

1 Interstage water knock out reported in total of stream 42
2 Compressor pressure profile is : In/Out stg 1:- 1.5/4.5 Bara;stg 2:-4/12 Bara;stg 3:-10/30 Bara; stg 4:-29.5/74 Bara
intermediate stream water contents not shown but correspond to saturation at 37.8 deg C for 1st two stages.
3 This stream is to and from prehaet train in power plant. See Alstom Dwg TS 29687 (DWG E9)

SEE DWG E12

1. FGD DESCRIPTION – SEE PROCESS FLOW FIG1

The following is a general description of ALSTOM's limestone, forced oxidation limestone/gypsum wet FGD system. The system removes up to 98,5% of the acid constituents present in flue gas by scrubbing with limestone. Gypsum, which may be sold or landfilled is produced as a byproduct. Since produced gypsum is disposal grade, gypsum will contain approximately 90% $CaSO_4 \cdot 2H_2O$ at 85% solids content. This gypsum is easily manageable and operating costs are lowered.

1.1 FLUE GAS PATH

For boiler capacities less than approximately 1,000 MWe, a single absorber can be fitted to each boiler unit. The flue gas is combined downstream of the boiler ID fans and taken directly to the WFGD system. After being treated in the absorber tower, the flue gas is discharged through a wet stack. The entire gas stream is treated in the absorber.

Under certain circumstances an excursion in flue gas temperature (e.g. an air heater failure or recycle pump trip) has the potential to damage absorber internals and absorber/ductwork linings. To avoid this possibility, an emergency flue gas quenching system is provided. If a flue gas over-temperature is detected, deluge valves open and water is sprayed into the absorber inlet duct from the plant fire protection system. This quenches the gas for the period of time necessary to close the isolation dampers Induced draft (ID) fans provide the draft to overcome the pressure drop across the boiler,
ESP and FGD system.

Stack gas temperature requirements (e.g. 85 °C) being imposed reheat is provided. Alternative include gas-to-gas reheater (GGH), liquid couple heat exchangers, partial bypass, and heated air injection.

The limestone/gypsum wet FGD system flue gas ductwork is fabricated of carbon steel. The absorber inlet duct (between the absorber expansion joint and the vessel wall) will be lined with C-276 alloy to prevent corrosion. The ductwork between the absorber outlet flange and the chimney breeching flange will also be protected against corrosion by metallic or organic linings.

1.2 ABSORBER

1.2.1 Absorption

ALSTOM employs a vertical, countercurrent, spray tower absorber for limestone/gypsum wet FGD systems. This technology was developed by ALSTOM in the mid-1970s and has been employed extensively on a worldwide basis since then. ALSTOM 's reference list includes absorbers that range in size from 5.5 m to 21.5 m in diameter, constructed with various types of alloys, stainless steels and mild steel with corrosion/erosion resistant linings.

The flue gas enters the spray tower near the bottom through an inlet zone of C276 that resists the corrosion that can take place at the wet/dry interface. Once in the absorber, the hot flue gas is immediately quenched as it travels upward countercurrent to a continuous spray of process (recycle) slurry produced by multiple spray banks. The recycle slurry (a 15 percent concentration slurry of calcium sulfate, calcium sulfite, unreacted alkali, inert materials, fly-ash and various dissolved materials) extracts the sulfur dioxide from the flue gas. Once in the liquid phase, the sulfur dioxide reacts with the dissolved alkali (calcium carbonate) to form dissolved calcium.

The quantity of recycle slurry needed to effectively remove the specified amount of SO2 is determined by a parameter known as the liquid-to-gas ratio (L/G). The choice of the L/G is based on ALSTOM 's extensive experience in design and operation of full scale units in conjunction with an ongoing research and development effort in such areas as oxidation, process effects of dissolved chloride ion and reagent particle size.

The design L/G is provided by multiple spray levels fed by dedicated recycle pumps. Each spray level consists of a bank of nitride-bonded silicon carbide spray nozzles designed to provide the proper sized droplets for optimum SO2 absorption, typically a d50 < 2,000 µm. The nozzles are arranged to ensure proper gas/liquid contact in the absorber.

1.2.2 Reaction tank

The recycle slurry falls from the spray zone into the reaction tank that forms the base of the absorber. This tank is sized to provide sufficient residence time for all of the FGD chemical reactions to take place. Typically, this is on the order of ten (10) hours. Fresh reagent slurry is added to the reaction tank where it reaches equilibrium with the bulk of the recycle slurry prior to being returned to the spray banks via the recycle pumps.

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1.2.3 Forced oxidation

Forced oxidation of the recycle slurry in a limestone wet FGD system produces a more manageable, easily handlable byproduct. To produce the fully oxidized byproduct, centrifugal blowers supply compressed air to a sparging system in the reaction tank. The oxygen in the air converts the dissolved calcium sulfite ($CaSO_3$) to calcium sulfate ($CaSO_4$), which then crystallizes as $CaSO_4 \cdot 2H_2O$, gypsum.

ALSTOM's oxidation air injection system utilizes lances located adjacent to each of the side-entering reaction tank agitators.The oxidation air, which has been heated in the compression process, is quenched and saturated with a stream of clean make up water. This is done to prevent any scaling or buildup that could occur at the sparger tips due to localized evaporation of recycle slurry.

1.2.4 Mist elimination

Two-stage chevron mist eliminators constructed of polypropylene will be provided. The first stage is washed in segments on a continuous basis from the front and back sides.

The second stage is washed in segments on a continuous basis from the front side. The wash headers are constructed of FRP and nozzles are constructed of polypropylene. The mist eliminator wash flux rates and pressures have been designed to provide effective rinsing of any solids or chemically reactive liquids.

Mist eliminator wash pumps are used to supply both the first and second stage mist eliminator wash. Water supply for the ME wash pumps will come from the make-up water tank.

1.3 REAGENT PREPARATION AND SLURRY DELIVERY

Limestone is delivered to the limestone silo serving the ball mill at a maximum size of 18 mm. The back-up ground limestone silo is to receive dry ground limestone at 90% passing through a 44 µm screen.

ALSTOM will supply an unground limestone system as described below The reagent preparation system is designed on the basis of the assumption of limestone grinding on 24 hour/day basis.

1.3.1 Limestone storage

The day bin is a cylindrical steel silo with a conical bottom used to store limestone for feed to the wet grinding system. This subsystem includes the bin, bin vent filter, vibrating bottom, shut off gate and support/access steel. The silo discharges to the limestone grinding system.

1.3.2 Limestone grinding

Limestone is fed from the day bin to a wet closed-circuit ball mill grinding system which produces a uniform slurry of limestone; FGD system reclaimed water is used as the dilution medium. The limestone grinding system consists of a ball mill, mill recycle tank, mill recycle pumps, classifiers and reagent feed tank. Hydrocyclones are used in the grinding loop to classify the mill product slurry; coarse limestone in the underflow is returned to the mill for regrinding and fine limestone in the overflow is delivered to the reagent feed tank where it is stored for use by the FGD system.
Limestone is fed from the day silo via a weigh belt feeder to a wet ball mill. The wet ball mill consists of a rubber-lined cylinder filled with hardened steel balls. In the ball mill, water is added and limestone is pulverized by the action of the balls as the mill rotates. Process make-up water is used for preparation of the limestone slurry, which is delivered to the reagent feed tanks for storage and use by the FGD system.

1.3.3 Slurry feed

Reagent slurry is transported from the reagent feed tank to the absorber through the use of a circulating feed loop. Slurry velocities are constantly maintained in the loop while at the same time providing the required reagent feed to the absorber. Control valves regulate the flow of reagent slurry to the reaction tank.

Reagent slurry is added to the reaction tank at the base of the absorber in response to two control signals. The primary control is a feed-forward loop driven by the SO2 concentration in the flue gas entering the FGD system. The pH in the reaction tank drives a feedback loop that trims the feed valve. The pH-trimmed system responds rapidly, is essentially independent of plant load, and is therefore highly stable.

1.3.4 Limestone grinding back-up system

A steel silo is utilized to store dry-ground limestone in the event the grinding system is down. The ground limestone is metered to the reagent feed tank where water is proportionately added.

1.4 DEWATERING AND PRODUCT HANDLING

1.4.1 Primary dewatering

Product slurry is pumped from the reaction tank to a bank of hydrocyclone classifiers which split the slurry into a low density stream of fines (the overflow) and a high density stream of coarse crystals (the underflow). In so doing, the hydrocyclones also classify the slurry chemically: unreacted limestone is relatively fine and reports to the overflow; the product gypsum is a coarse material and it preferentially reports to the underflow. The hydrocyclone underflow product flows by gravity directly to a horizontal vacuum belt filter for further dewatering. The overflow is directly returned to the absorber reaction tank by gravity flow. A small portion of the overflow is bled from the FGD system in order to limit the chloride content in the recycle slurry.

1.4.2 Secondary dewatering

The hydrocyclone underflow product is routed to a horizontal vacuum belt filter which further dewaters the product slurry to approximately 85% solids. A liquid ring vacuum pump provides the suction needed at the filter cloth. Extracted filtrate is routed to a receiver tank and fed from there to the dewatering area/filtrate sump for reuse in the system.

1.4.3 Byproduct handling

The dewatered gypsum product is discharged directly from the vacuum filter to the belt filter discharge coveyor. The limit of supply is the gypsum outlet from the horizontal belt filter discharge conveyor.

2. DESIGN DATA , PERFORMANCES AND MASS FLOW - PLANT A

2.1 DESIGN DATA – PLANT A

Coal Type	Bituminous		
Coal Source	Eastern Australia		
Fuel Fired Rate	66.6	kg/s	
Excess air at FGD inlet	30.2	%	
Coal Analysis Proximate Analysis			
Coal (dry, ash-free)	78.3	% w/w	
Ash	12.2	% w/w	
Moisture	9.5	% w/w	
Ultimate Analysis			
Carbon	64.60	% w/w	
Hydrogen	4.38	% w/w	
Oxygen	7.05	% w/w	
Nitrogen	1.41	% w/w	
Sulphur	0.86	% w/w	
Chlorine	0.02	% w/w	
Moisture	9.5	% w/w	
Ash	12.2	% w/w	
Fuel GCV	27.06	MJ/kg	
Fuel NCV	25.87	MJ/kg	
Design Data			
SO2 Inlet loading & Emissions			
SO2 content of inlet flue gas @ 6%O2, dry	660	ppm	
	1880	mg/Nm3	
Target SO2 removal efficiency	**90.0**	**%**	
Target SO2 content of outlet flue gas @ 6% O2, dry	70	ppm	
Flue gas flow rate	812	Kg/s	
Flue gas temperature	115	°C	
Location (indoor / outdoor)	Outdoor		
Wind / snow loading			
Site elevation	sea level		
Barometric pressure	1013	mbar	
Ambient Air Relative Humidity	60	%	
Ambient Air Temperature	9.0	oC	

2.2 PERFORMANCE AND MASS FLOW – PLANT A

GAS STREAM FLOW

	Absorber Inlet	Absorber Outlet
Flow kg/hr (Nm3/hr)	2 925 000 (2219000)	2 973 500 (227 000)
Pressure kPa	103,302	102,06
Temp °C	118	47 (85°C after GGH)
SO2 mg/Nm3	1854	181
Particulates mg/Nm3	27	13

Liquid / Solid flow

Limestone flow 6387 kg/hr

Gypsum by product flow
Solid : 10480 kg/h
Water : 1100 kg/hr

Fresh water : 46 m3/hr

Chloride purge flow
Solid : 20kg/hr
Water : 575 kg/hr
Chloride ppm (aq) : 30000

Electricity consumption 5,5 MW

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3. DESIGN DATA , PERFORMANCES AND MASS FLOW - CASE B

3.1 DESIGN DATA

Coal Type	Bituminous		
Coal Source	Eastern Australia		
Fuel Fired Rate	74	kg/s	
Excess air at FGD inlet	30.2	%	
Coal Analysis Proximate Analysis			
Coal (dry, ash-free)	78.3	% w/w	
Ash	12.2	% w/w	
Moisture	9.5	% w/w	
Ultimate Analysis			
Carbon	64.60	% w/w	
Hydrogen	4.38	% w/w	
Oxygen	7.05	% w/w	
Nitrogen	1.41	% w/w	
Sulphur	0.86	% w/w	
Chlorine	0.02	% w/w	
Moisture	9.5	% w/w	
Ash	12.2	% w/w	
Fuel GCV	27.06	MJ/kg	
Fuel NCV	25.87	MJ/kg	
Design Data			
SO2 Inlet loading & Emissions			
SO2 content of inlet flue gas @ 6%O2, dry	660	ppm	
	1880	mg/Nm3	
Target SO2 removal efficiency	**98,5**	**%**	
Target SO2 content of outlet flue gas @ 6% O2, dry	10	ppm	
Flue gas flow rate	902	Kg/s	
Flue gas temperature	115	°C	
Location (indoor / outdoor)	Outdoor		
Wind / snow loading			
Site elevation	sea level		
Barometric pressure	1013	mbar	
Ambient Air Relative Humidity	60	%	
Ambient Air Temperature	9.0	oC	

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3.2 PERFORMANCE AND MASS FLOW

Gas stream flow

	Absorber Inlet	**Absorber Outlet**
Flow kg/hr (Nm3/hr)	3 250 000 (2 464 000)	3 350 000 (2587 500)
Pressure kPa	103,066	101 ?5
Temp °C	117	51 (85°C after GGH)
SO2 mg/Nm3	1854	26
Particulates mg/Nm3	27	13

Liquid / Solid flow

Limestone flow 7730 kg/hr

Gypsum by product flow
Solid : 12730 kg/h
Water : 1325 kg/hr

Fresh water : 99 m3/hr

Chloride purge flow
Solid : 20kg/hr
Water : 590kg/hr
Chloride ppm (aq) : 30000

Electricity consumption 7 MW

4. SCOPE AND BUDGET CAPITAL COST

4.1 SCOPE

Flue gas desulphurisation system scope including :

- ✓ booster fan
- ✓ ducts
- ✓ GGH
- ✓ absorber island
- ✓ limestone storage
- ✓ limestone slurry preparation
- ✓ gypsum dewatering and storage
- ✓ ele/I&C
- ✓ buildings
- ✓ erection
- ✓ commissioning
- ✓ training

with material as per ALSTOM standard

but excluding:

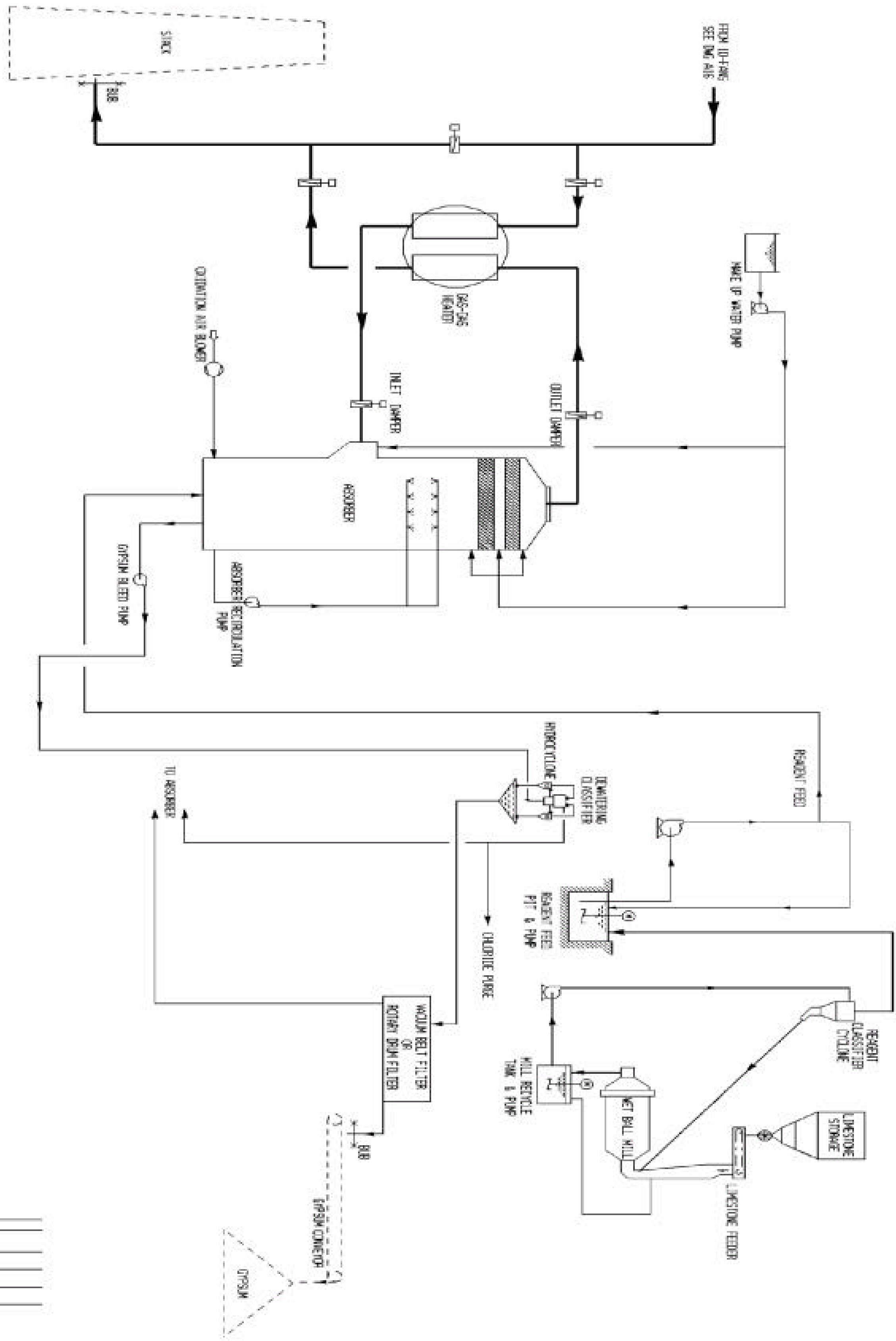
- ✓ civil works
- ✓ stack
- ✓ WWTP

4.2 BUDGET CAPITAL COST

Budget capital cost for Plant A for the FGD system ~83 M€

Budget capital cost for Plant B for the FGD ~ 90 M€

Fig 1 Flue Gas Desulfurisation System – general process flow diagram



Issue

A1

Client	**Fluor Ltd**
Licensee	N/A
No. of Boilers	1
No. of DeNOx Reactors	2
Location (Hot / Cold Side)	Hot Side
Sales Number	-

DESIGN AND OPERATING CONDITIONS - SUMMARY	Units	
Fuels	-	Coal (Eastern Australian)
Station Rating	MWe Gross	830
Plant Design Operating Load	%MCR	100%
Flue Gas Flow Rate	kg/s	776.2
	kg/h	2,794,255
	Nm^3/h, wet	2,122,806
Gas Temperature	^oC	380
Oxygen in Flue Gas	%v/v, wet	3.29
Flue Gas Inlet NO_x Concentration	vppm @ 6%O_2 v/v, dry	317
Flue Gas Inlet SO_2 Concentration	vppm @ 6%O_2 v/v, dry	660
Moisture in Flue Gas	%v/v	8.86
Dust Loading	mg/Nm^3@ 6%O_2 v/v, dry	13,340
Gas Outlet NO_x Concentration	vppm @ 6%O_2 v/v, dry	98
Gas Outlet NO_2 Concentration (assumed maximum 5% of total NOx)	vppm @ 6%O_2 v/v, dry	5
Maximum allowable NO_2 Concentration for Amine Scrubbing	vppm @ 6%O_2 v/v, dry	10
NO_x Removal Efficiency	%	69

Plant Description

The catalytic DeNOx reactor is situated in the gas stream between the boiler outlet and the airheater. The reactor comprises catalyst tier(s) in a number of units with space allowed for future units. A system of rails and runway beams is incorporated for initial and future catalyst loading.

Gaseous ammonia is added to air supplied from the FD fan in a mixer and injected into the flue gas via a grid of headers and nozzles in a horizontal flue shortly after the boiler.

Turning vanes are incorporated in the flue bends between the ammonia injection grid and the reactor to ensure good flow and ammonia distribution. A flow of straightening device (screen plate) is installed above the reactor inlet and a protector grating immediately on top of the catalyst.

An appropriate C & I system is necessary to facilitate operation of the DeNOx system.

Issue	Date	Reason For Change	By	Chk'd		Rev'd / App'd	
D							
C							
B							
A1	08/04/04	Draft Issue	RSP				

Issue A1

DESIGN AND OPERATING CONDITIONS	Units			
		1	2	3
Load Case	%MCR	100%		
Fuel	-	Coal	Coal	Coal
Flue Gas Flowrate	kg/s	776.2		
	Nm^3/h, wet	2,122,806		
Flue Gas Temperature	^oC	380		
Gas Composition at Reactor Inlet				
O_2	%v/v, wet	3.30		
CO_2	%v/v, wet	13.97		
SO_2	%v/v, wet	0.07		
H_2O	%v/v, wet	8.80		
Ar	%v/v, wet	0.87		
N_2	%v/v, wet	73.01		
NO_x	vppm @ 6%O_2 v/v, dry	317		
SO_2	vppm @ 6%O_2 v/v, dry	660		
SO_3	vppm @ 6%O_2 v/v, dry	10		
Dust Burden	mg/Nm^3@ 6%O_2 v/v, dry	13,340		
Gas Composition at Reactor Outlet				
NO_x	vppm @ 6%O_2 v/v, dry	< 98		
NO_2	vppm @ 6%O_2 v/v, dry	< 5		
SO_3	vppm @ 6%O_2 v/v, dry	< 10		
NH_3 (slip)	vppm @ 6%O_2 v/v, dry	< 5		
Catalyst Pressure Drop	Pa			
DeNOx Plant Pressure Drop (Inlet of Ammonia Injection Grid to DeNOx Outlet)	Pa			

Notes:

Issue	Date	Reason For Change	By	Chk'd	Rev'd / App'd
D					
C					
B					
A1	08/04/04	Draft Issue	RSP		

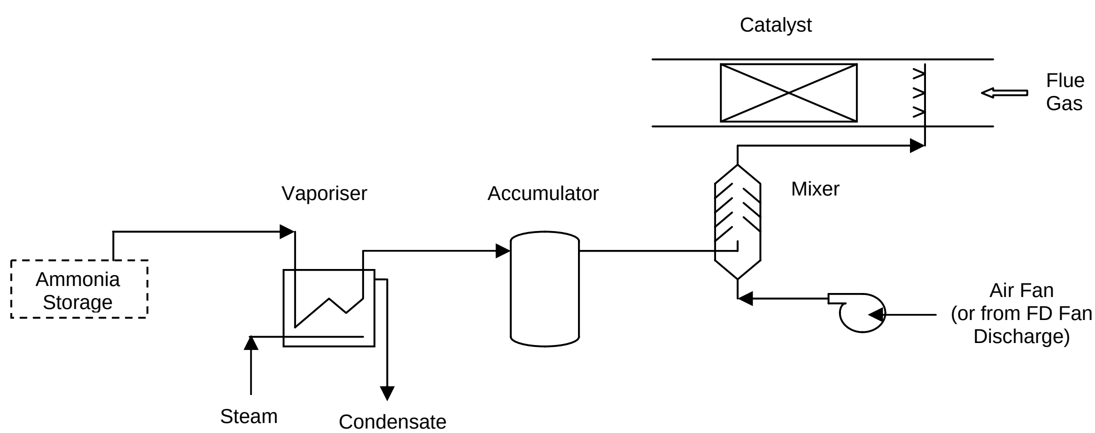
Issue

A1

Ammonia / Air System

Condition			Vaporiser (H_2O side)	Vaporiser (NH_3 side)	Accumulator	Mixer (after)	Air supply	Grid (gas side)
Operating	Flow	Nm^3/h		545	545	10,900	10,355	2,122,806
		kg/h		420	420	8,480	8,060	2,794,255
	Temperature	°C	~45	~35	~35	~35	~35	380
	Pressure	MPa (g)	see note 1	0.29	0.15			
	Concentration	%				5% NH3		
Design Limits	Pressure	MPa (g)						
	Pressure	MPa (g)						
	Temperature	°C						
	Concentration	%						

Notes
*1 Depends on Steam Supply



Issue	Date	Reason For Change	By	Chk'd	Rev'd / App'd
D					
C					
B					
A1	08/04/04	Draft Issue	RSP		

Issue A1

Client	**Fluor Ltd**
Licensee	N/A
No. of Boilers	1
No. of DeNOx Reactors	2
Location (Hot / Cold Side)	Hot Side
Sales Number	-

DESIGN AND OPERATING CONDITIONS - SUMMARY	Units	
Fuels	-	Coal (Eastern Australian)
Station Rating	MWe Gross	827
Plant Design Operating Load	%MCR	100%
Flue Gas Flow Rate	kg/s	861.9
	kg/h	3,102,772
	Nm^3/h, wet	2,357,186
Gas Temperature	^oC	380
Oxygen in Flue Gas	%v/v, wet	3.29
Flue Gas Inlet NO_x Concentration	vppm @ 6%O_2 v/v, dry	317
Flue Gas Inlet SO_2 Concentration	vppm @ 6%O_2 v/v, dry	660
Moisture in Flue Gas	%v/v	8.86
Dust Loading	mg/Nm^3@ 6%O_2 v/v, dry	13,340
Gas Outlet NO_x Concentration	vppm @ 6%O_2 v/v, dry	98
Gas Outlet NO_2 Concentration (assumed maximum 5% of total NOx)	vppm @ 6%O_2 v/v, dry	5
Maximum allowable NO_2 Concentration for Amine Scrubbing	vppm @ 6%O_2 v/v, dry	10
NO_x Removal Efficiency	%	69

Plant Description

The catalytic DeNOx reactor is situated in the gas stream between the boiler outlet and the airheater. The reactor comprises catalyst tier(s) in a number of units with space allowed for future units. A system of rails and runway beams is incorporated for initial and future catalyst loading.

Gaseous ammonia is added to air supplied from the FD fan in a mixer and injected into the flue gas via a grid of headers and nozzles in a horizontal flue shortly after the boiler.

Turning vanes are incorporated in the flue bends between the ammonia injection grid and the reactor to ensure good flow and ammonia distribution. A flow of straightening device (screen plate) is installed above the reactor inlet and a protector grating immediately on top of the catalyst.

An appropriate C & I system is necessary to facilitate operation of the DeNOx system.

Issue	Date	Reason For Change	By	Chk'd		Rev'd / App'd	
D							
C							
B							
A1	08/04/04	Draft Issue	RSP				

Data Sheet for - SCR DeNOx : **Case 4 with CO2 Capture : Amine Scrubbing**

Issue A1

DESIGN AND OPERATING CONDITIONS	Units			
		1	2	3
Load Case	%MCR	100%		
Fuel	-	Coal	Coal	Coal
Flue Gas Flowrate	kg/s	776.2		
	Nm^3/h, wet	2,122,806		
Flue Gas Temperature	^oC	380		
Gas Composition at Reactor Inlet				
O_2	%v/v, wet	3.30		
CO_2	%v/v, wet	13.97		
SO_2	%v/v, wet	0.07		
H_2O	%v/v, wet	8.80		
Ar	%v/v, wet	0.87		
N_2	%v/v, wet	73.01		
NO_x	vppm @ 6%O_2 v/v, dry	317		
SO_2	vppm @ 6%O_2 v/v, dry	660		
SO_3	vppm @ 6%O_2 v/v, dry	10		
Dust Burden	mg/Nm^3@ 6%O_2 v/v, dry	13,340		
Gas Composition at Reactor Outlet				
NO_x	vppm @ 6%O_2 v/v, dry	< 98		
NO_2	vppm @ 6%O_2 v/v, dry	< 5		
SO_3	vppm @ 6%O_2 v/v, dry	< 10		
NH_3 (slip)	vppm @ 6%O_2 v/v, dry	< 5		
Catalyst Pressure Drop	Pa			
DeNOx Plant Pressure Drop (Inlet of Ammonia Injection Grid to DeNOx Outlet)	Pa			

Notes:

Issue	Date	Reason For Change	By	Chk'd		Rev'd / App'd	
D							
C							
B							
A1	08/04/04	Draft Issue	RSP				

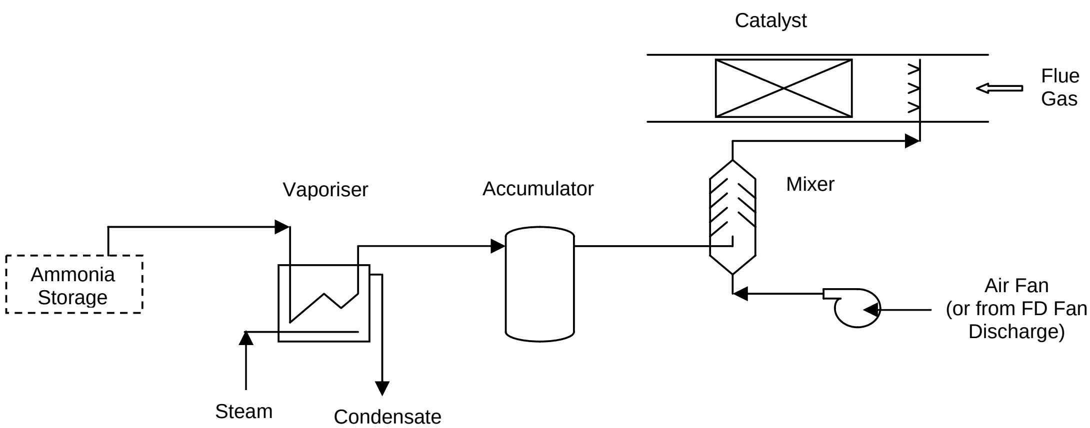
Issue

A1

Ammonia / Air System

Condition			Vaporiser (H_2O side)	Vaporiser (NH_3 side)	Accumulator	Mixer (after)	Air supply	Grid (gas side)
Operating	Flow	Nm^3/h		603	603	12,060	11,457	2,357,186
		kg/h		465	465	9,385	8,920	3,102,772
	Temperature	°C	~45	~35	~35	~35	~35	380
	Pressure	MPa (g)	see note 1	0.29	0.15			
	Concentration	%				5% NH3		
Design Limits	Pressure	MPa (g)						
	Pressure	MPa (g)						
	Temperature	°C						
	Concentration	%						

Notes
*1. Depends on Steam Supply



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SECTION F COST ESTIMATES FOR CASES

1.0 Introduction

This section summarises the cost estimating methodology used in preparing the case study capital cost estimates shown on Tables F 1-4.

These capital cost estimates were then used in the economic evaluation which is described in Section G "Economic Comparisons".

2.0 Estimate Basis

2.1 Basic data

The basic data for each of the cases examined is given in the technical documentation collected in this report. This data was used with the work breakdown structure described below to format the estimates. The estimate summary sheets show the work breakdown structure as a series of columns which are self explanatory.

2.2 Estimate Structure

Direct Field Costs:-

Costs for the NGCC cases have been estimated by factoring the equipment costs for the various items making up the plant. Factors are applied as multipliers to these equipment costs to arrive at a direct field cost which is defined as the cost of the equipment and its installation and it comprises equipment cost plus construction costs plus the bulk materials (piping etc).

Equipment costs have been scaled (based on comparisons of mass balance flows) from estimates from other projects which are based on considerably more extensive engineering design than has been undertaken for this study. In the case of the HRSG, gas turbines and steam turbine generators, budget prices were elicited form the market.

In the case of buildings and some of the large electrical equipment the factors are "bypassed" and the bare costs are taken straight into the direct field cost subtotal.

Different factors have been used for different plant sections. These are shown on the estimate summary sheets as installation factors and are based on Fluor experience and are determined from analyses of estimates for real projects which have been built from lump sum bids. They are therefore realistic and represent current and competitive market conditions.

In cases 3 and 4 in which the boiler and power islands were estimated by Mitsui Babcock and Alstom Power, the direct field costs are shown as the sum of direct material plus construction. In the case of these plants slightly different estimating methodologies are used to determine direct costs since the construction costs have a different structure to those of an NGCC and carbon dioxide capture plant. The equipment and bulk construction materials and labour are much less easy to differentiate from the bare equipment cost.

Indirect Field Costs:-

These are added to the direct field costs as a series of percentages to allow for the site based activities

Engineering Costs:-

These are the home office costs of the engineering contractors and are typical found to be about 12% of the direct field cost.

Contingency:-

A 10% contingency has been added to the total installed cost (TIC=DFC+IFC+EC).

Owners Costs:-

A 7% allowance based on the TIC has been made to cover owners costs.

(license fees were applicable have been consolidated into the DFC)

2.3 Overall Project Cost:-

This is the sum of all the estimate items including contingencies and owners costs and is the sum used in the economic evaluations.

The estimates shown on the summary sheets have then been benchmarked on a specific investment cost basis (US$/kWh) to ensure that they are representative of current market prices. Thus the estimates represent a likely price of the plants in the market. This benchmarking only applies to the bottom line price and should not be extended to individual plant section cost breakdowns.

2.4 A Note on Currencies

The NGCC plants and the carbon dioxide capture plants were estimated in US$ whereas some of the PF plant cases were estimated in Euros.

In the case of Euro pricing, a conversion has been made at parity rates of 1 Euro = 1 US$. This takes no account of the recent trends in cross Dollar/Euro rates. Currently the rates are far from parity.

However, these recent instabilities have not yet found there way into the historical estimating data base which has been used in this study. No one can predict where the dollar will be relative to the Euro in the future.

3.0 Work Breakdown Structure Unit Numbers

CASE 1 Stand alone NGCC

1000	Power generation plant
4000	Balance of plant and off-sites

CASE 2 NGCC plus capture

1001	Power generation plant
2000	CO_2 capture plant
3000	CO_2 compression and drying
4001	Balance of plant and off-sites

CASE3 Standalone USCPF

100	Coal / ash handling
200	Boiler island
300	FGD
400	SCR DENOX
500	Steam turbine plant and generators
800	Balance of plant and off-sites

CASE 4 USCPF plus capture

100	Coal / ash handling
200	Boiler island
300	FGD
400	SCR DENOX
500	Steam turbine plant and generators
600	CO_2 capture
700	CO_2 Compression and drying
800	Balance of plant and off-sites

4.0 Estimate Summary Sheets

These are shown on the summary excel spread sheets Tables F1-4.

- Table F1 : CASE 1 NGCC without carbon dioxide capture
- Table F2 : CASE 2 NGCC with carbon dioxide capture
- Table F3 : CASE 3 USCPF without carbon dioxide capture
- Table F3 : CASE 3 USCPF with carbon dioxide capture

5.0 Outline Equipment Listing

The estimate has been based on the equipment and system scope described in the following listings classified according to the work breakdown structure.

EQUIPMENT LISTING CASE 1

1000 UNIT

Gas Turbine power generators (2)
Steam Turbine power generator
Surface condenser
Fuel gas heater
HRSG (2)
HP feed water pumps
Vac condensate pumps
GT drain sump pump
Fuel gas filter separator
BFW chemical injection
Intermittent blow down drum
Continuous blow down drum
Condensate return tank
OHD crane GT
OHD crane STG

4000 UNIT

Demin water storage tankage
Raw water and firewater storage
Plant air compression skid
Emergency diesel generator system
Closed loop water cooler
Blowdown water sump
Condensate return pump
Demin water pump
Sea water pumps
Sea water circulation pumps
Close loop CW pumps
Oily water sump pump
Fire pumps (diesel)
Fire pumps (electric)
FW jockey pump
Water treatment plant
Seawater chemical injection
OWS
Sea water inlet/outlet works

BUILDINGS

Generation building
HRSG building
Steam turbine building
CO_2 compressor building
Admin/control/lab
Warehouse
Demin
GIS building
Sea water inlet
Fuel gas expander
Auxiliary sub stations

ELECTRICAL EQUIPMENT

Breakers
Step up transformers
Station transformers
Switch gear
MCC
UPS inverters
VDC station battery
Turbine bus ducts

EQUIPMENT LISTING CASE 2

1001 UNIT

Gas Turbine power generators (2)
Steam Turbine power generator
Surface condenser
Fuel gas Heater
HRSG (2)
HP feed water pumps
Vac condensate pumps
GT drain sump pump
Fuel gas filter separator
BFW chemical injection
Intermittent blow down drum
Continuous blow down drum
Condensate return tank
OHD crane GT
OHD crane STG

2000 UNIT

DCC circulation pumps
Wash water pumps
Rich amine pumps
Reflux pump
Stripper bottoms pump
MEA pumps
Surplus water pump
Flue gas blowers
Amine filter package
Soda ash dosing
Reclaimer
DCC towers
Packing
Absorption towers
Stripper
Packing for stripper
Semi lean flash drum
Ohd accumulator

MEA storage
Surplus water tankage
DCC coolers
Water wash cooler
Cross exchangers
Flash preheater
Overhead stripper condenser
Stripper reboiler
Lean solvent cooler

3000 UNIT

Compression package
Dryer
CO_2 pumps

4001 UNIT

Demin water storage tankage
Raw water and firewater storage
Plant air compression skid
Emergency diesel generator system
Closed loop water cooler
Blowdown water sump
Condensate return pump
Demin water pump
Sea water pumps
Sea water circulation pumps
Close loop CW pumps
Oily water sump pump
Fire pumps (diesel)
Fire pumps (electric)
FW jockey pump
Water treatment plant
Seawater chemical injection
OWS
Sea water inlet/outlet works
Bulk MEA storage
MEA pumps
Amine sumps

BUILDINGS

Generation building
HRSG building
Steam turbine building
CO_2 compressor building
Admin/control/lab
Warehouse
Demin
GIS building
Sea water inlet
Fuel gas expander
Auxiliary sub stations

ELECTRICAL EQUIPMENT

Breakers
Step up transformers
Station transformers
Switch gear
MCC
UPS inverters
VDC station battery
Turbine bus ducts

EQUIPMENT LISTING CASE 3

100 UNIT

Coal delivery equipment
Stacker reclaimer
Yard equipment
Transfer towers
Crusher and screen house
Dust suppression equipment
Ventilation equipment
Belt feeders
Metal detection
Belt weighing equipment
Miscellaneous equipment
Bottom ash systems
Fly ash systems

200 UNIT

Furnace
Reheater
Superheater
Economiser
Piping
Air handling plant
Structures
Bunkers
Pumps
Coal feeders
Soot blowers
Blow down systems
Dosing equipment
Mills
Auxiliary boiler
Miscellaneous equipment

300 UNIT

Priced as a turnkey package (see process descriptions)

400 UNIT

Flues
Reactor casing
Bypass system
Catalyst
Ammonia injection equipment
Handling equipment
Control system

500 UNIT

Steam turbine island package

800 UNIT

Demin water storage tankage
Raw water and firewater storage
Plant air compression skid
Emergency diesel generator system
Closed loop water cooler
Blowdown water sump
Condensate return pump
Demin water pump
Sea water pumps
Sea water circulation pumps
Close loop CW pumps
Oily water sump pump
Fire pumps (diesel)
Fire pumps (electric)
FW jockey pump
Water treatment plant
Seawater chemical injection
OWS
Sea water inlet/outlet works

Buildings

Electrical equipment

EQUIPMENT LISTING CASE 4

100 UNIT

Coal delivery equipment
Stacker reclaimer
Yard equipment
Transfer towers
Crusher and screen house
Dust suppression equipment
Ventilation equipment
Belt feeders
Metal detection
Belt weighing equipment
Miscellaneous equipment
Bottom ash systems
Fly ash systems

200 UNIT

Furnace
Reheater
Superheater
Economiser
Piping
Air handling plant
Structures
Bunkers
Pumps
Coal feeders
Soot blowers
Blow down systems
Dosing equipment
Mills
Auxiliary boiler
Miscellaneous equipment

300 UNIT

Priced as a turnkey package (see process descriptions)

400 UNIT

Flues
Reactor casing
Bypass system
Catalyst
Ammonia injection equipment
Handling equipment
Control system

500 UNIT

Steam turbine island package

600 UNIT

DCC circulation pumps
Wash water pumps
Rich amine pumps
Reflux pump
Stripper bottoms pump
MEA pumps
Surplus water pump
Flue gas blowers
Amine filter package
Soda ash dosing
Reclaimer
DCC towers
Packing
Absorption towers
Stripper
Packing for stripper
Semi lean flash drum
Ohd accumulator
MEA storage
Surplus water tankage
DCC coolers
Water wash cooler
Cross exchangers
Flash preheater

Overhead stripper condenser
Stripper reboiler
Lean solvent cooler

700 UNIT

Compression package
Dryer
CO_2 pumps

800 UNIT

Demin water storage tankage
Raw water and firewater storage
Plant air compression skid
Emergency diesel generator system
Closed loop water cooler
Blowdown water sump
Condensate return pump
Demin water pump
Sea water pumps
Sea water circulation pumps
Close loop CW pumps
Oily water sump pump
Fire pumps (diesel)
Fire pumps (electric)
FW jockey pump
Water treatment plant
Seawater chemical injection
OWS
Sea water inlet/outlet works

Buildings

Electrical equipment

TABLE F 1

All costs in Millions of dollars **CASE 1 NGCC without carbon dioxide capture**

DESCRIPTION		1000 power	2000 CO2	3000 CO2 comp	4000 Balance of plant	TOTAL
Equipment cost		130.65			7.37	
Installation factor		1.53			1.61	
Bldgs and electrical equipment		0.00			14.30	
Infrastructure (blgs + electrical)					42.99	
DIRECT FIELD COST (DFC)		**200.00**			**69.00**	**269.00**
	%DFC					
Construction management	2	4.00			1.38	5.38
Commissioning	2	4.00			1.38	5.38
Commissioning spares	0.5	1.00			0.35	1.35
Temporary facilities	5	10.00			3.45	13.45
Vendor reps attendance		1.00			0.00	1.00
Heavy lifts		1.00			0.00	1.00
Freight, taxes &insurance	1	2.00			0.69	2.69
INDIRECT FIELD COSTS		**23.00**			**7.00**	**30.00**
ENGINEERING COSTS	**12**	**24.00**			**8.00**	**32.00**
TOTAL INSTALLED COST		**247.00**			**84.00**	**331.00**
CONTINGENCY	**10**	**25.00**			**8.40**	**33.40**
License fees						
Owners costs	7	17.29			5.88	23.17
OVERALL PROJECT COST		**289**			**98**	**388**

TABLE F 2

All costs in Millions of dollars **CASE 2 NGCC With carbon dioxide capture**

DESCRIPTION		1001 power	2000 CO2	3000 CO2 comp	4001 Balance Of Plant	TOTAL
Equipment cost		130.65	34.64	14.04	11.25	
Installation factor		1.53	2.60	1.78	1.61	
Bldgs and electrical equipment		0.00			20.35	
Infrastructure(bldgs+electrical)					42.99	
DIRECT FIELD COST (DFC)		**200.00**	**90.00**	**25.00**	**82.00**	**397.00**
	%DFC					
Construction management	2	4.00	1.80	0.50	1.64	7.94
Commissioning	2	4.00	1.80	0.50	1.64	7.94
Commissioning spares	0.5	1.00	0.45	0.13	0.41	1.99
Temporary facilities	5	10.00	4.50	1.25	4.10	19.85
Vendor reps attendance		1.00	1.00	1.00	0.00	3.00
Heavy lifts		1.00	1.00		0.00	2.00
Freight, taxes &insurance	1	2.00	0.90	0.25	0.82	3.97
INDIRECT FIELD COSTS		**23**	**11**	**4**	**9**	**47**
ENGINEERING COSTS	**12**	**24**	**11**	**3**	**10**	**48**
TOTAL INSTALLED COST		**247**	**112**	**32**	**100**	**491**
CONTINGENCY	**10**	**25**	**11**	**3**	**10**	**49**
License fees						
Owners costs	7	17.29	7.86	2.21	7.03	34.39
OVERALL PROJECT COST		**289**	**131**	**37**	**118**	**575**

TABLE F 3

All costs in Millions of dollars **CASE 3 USCPF without carbon dioxide capture**

DESCRIPTION		**100 Coal/Ash Handling**	**200 Boiler Island**	**300 FGD**	**400 DeNox**	**500 steam turbines**	**600 CO2 capture**	**700 CO2 Comp Drying**	**800 BOP**	**TOTAL**
Direct Materials		35.00	130.00		12.00	88.00			125.00	
Construction		15.00	90.00	**see below**	3.00	35.00			40.00	
DIRECT FIELD COST (DFC)		**50.00**	**220.00**	**73.00**	**15.00**	**123.00**			**165.00**	**646.00**
	%DFC									
Construction management	2	1.00	4.40	1.46	0.30	2.46			3.30	12.92
Commissioning	2	1.00	4.40	1.46	0.30	2.46			3.30	12.92
Commissioning spares	0.5	0.25	1.10	0.37	0.08	0.62			0.83	3.23
Temporary facilities	5	2.50	11.00	3.65	0.75	6.15			8.25	32.30
Vendor reps attendance										
Heavy lifts										
Freight, taxes &insurance	1	0.50	2.20	0.73	0.15	1.23			1.65	6.46
INDIRECT FIELD COSTS		**5**	**23**	**8**	**2**	**13**			**17**	**68**
ENGINEERING COSTS	**12**	**6**	**26**	**9**	**2**	**15**			**20**	78
TOTAL INSTALLED COST		**61**	**270**	**89**	**18**	**151**			**202**	**791**
CONTINGENCY	**10**	**6**	**27**	**9**	**2**	**15**			**20**	**79**
License fees										
Owners costs	7	4.29	18.87	6.26	1.29	10.55			14.15	55.39
OVERALL PROJECT COST		**72**	**315**	**105**	**21**	**176**			**236**	**926**

TABLE F 4

All costs in Millions of dollars **CASE 4 USCPF With Carbon dioxide capture**

DESCRIPTION		100 Coal/Ash Handling	200 Boiler Island	300 FGD	400 DeNox	500 steam turbines	600 CO2 capture	700 CO2 Comp Drying	800 BOP	TOTAL
Direct Materials		38.00	141.00		13.00	88.00	32.10	22.47	136.00	
Construction		16.00	98.00	see below	3.00	35.00	53.60	17.52	43.00	
DIRECT FIELD COST (DFC)		**54**	**239**	**79**	**15**	**123**	**86**	**40**	**179**	**815**
	%DFC									
Construction management	2	1.08	4.78	1.58	0.30	2.46	1.71	0.80	3.58	16.29
Commissioning	2	1.08	4.78	1.58	0.30	2.46	1.71	0.80	3.58	16.29
Commissioning spares	0.5	0.27	1.20	0.40	0.08	0.62	0.43	0.20	0.90	4.07
Temporary facilities	5	2.70	11.95	3.95	0.75	6.15	4.29	2.00	8.95	40.74
Vendor reps attendance										
Heavy lifts										
Freight, taxes &insurance	1	0.54	2.39	0.79	0.15	1.23	0.86	0.40	1.79	8.15
INDIRECT FIELD COSTS		**6**	**25**	**8**	**2**	**13**	**9**	**4**	**19**	**86**
ENGINEERING COSTS	**12**	**6**	**29**	**9**	**2**	**15**	**10**	**5**	**21**	98
TOTAL INSTALLED COST		**66**	**293**	**97**	**18**	**151**	**105**	**49**	**219**	**998**
CONTINGENCY	**10**	**7**	**29**	**10**	**2**	**15**	**10**	**5**	**22**	**100**
License fees										
Owners costs	7	4.63	20.49	6.77	1.29	10.55	7.35	3.43	15.35	69.86
OVERALL PROJECT COST		**77**	**343**	**113**	**21**	**176**	**123**	**57**	**257**	**1168**

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SECTION G

ECONOMIC COMPARISONS

1.0 Introduction

This section presents the economic evaluation of the cases, using the capital cost data from Section F and the production cost data for each case from Section E.

An economic model has been developed based on that used by IEA-GHG. This model calculates production costs of electricity on a levelised basis. In other words it calculates a revenue stream equal to the discounted production costs plus the discounted capital costs. This sum is adjusted by the model in a series of iterations to produce a zero NPV of the operating and capital expenditure costs over the project life.

In other words it calculates the selling price of electricity which returns a zero net present value over the project life. This is equivalent to the levelised production cost of power determined at the battery limit of the plant. It does not include any distribution cost.

2.0 Base Data

2.1 Design and Construction

NGCC and USCPF cases have been evaluated with the following investment profiles:

NGCC

Year 1	40% investment
Year 2	40%
Year 3	20%

Total design and construction period is 2.5 years

USCPF

Year 1	20% investment
Year 2	45%
Year 3	35 %

Total design and construction period is 3.0 years

FLUOR experience suggests that the IEA GHG criterion of building an NGCC plant in 24 months is not realistic even though many projects are bid on that basis (with the consequential LD costs for non performance being passed onto the suppliers with a corresponding increase in capital cost. Twenty seven months, with thirty nearer the mark, could possibly be achieved for an NGCC plant if all of the equipment was single source).

2.2 Load Factor

All cases are assumed to achieve an 85% load factor in the year following commissioning and start-up. A three month commissioning period has been assumed directly following the construction period. It has been assumed that there is no sales of power during the commissioning period.

(In terms of load factors there is published data which shows that 90% availability has been achieved in modern USCPF plants in Denmark so 85% is if anything a conservative assumption).

2.3 Project Life

This is 25 years for all cases.

2.4 Discount Rates

Cases are run at 10% and a base case sensitivity case of 5%.

2.5 Cost of Debt

This is ignored as finance structures have not been considered.

2.6 Contingencies and Owners Costs

These are shown in the CAPEX estimates at 10% contingency and 7% owners costs.

2.7 Operating Costs

These are calculated from the chemicals and consumable summaries presented below and are tabulated on the summary of annual operating cost for an ideal year (Table G3 below). Note that these costs exclude amine unit residue disposal costs.

This summary of costs is extracted from the economic model output.. The definition of an ideal year is 365 days x 24 operating hours. These costs are then scaled back in the DCF calculation model by the annual operating factor to calculate the actual operating costs for a real operating year. The costs are calculated using the following parameters:

Operator cost and supervision 50k US$/Yr per operator (5 shift teams).

Operating Labour overhead 30%.

Maintenance 2.5% of capex for fluid/gas handling plants and 4% for solids handling portions of plants.

Insurance and taxes 2% of Capex per year.

TABLE G3 OPERATING COST SUMMARY

SUMMARY OF ANNUAL OPERATING COSTS FOR AN IDEAL YEAR (MMUS$)

	NGCC WITHOUT CO2 CAPTURE(CASE 1)				NGCC WITH CO2 CAPTURE(CASE 2)			
Fuel Price	3$/GJ	6$/GJ	1.5$/GJ	$3/GJ	3$/GJ	6$/GJ	1.5$/GJ	$3/GJ
Discount rate	**10%**	**10%**	**10%**	**5%**	**10%**	**10%**	**10%**	**5%**
	800 MW GROSS OUTPUT%				**740 MW GROSS OUTPUT**			
Fuel	132	264	66	132	132	264	66	132
Chemicals and Consumables	0.35	0.35	0.35	0.35	6.48	6.48	6.48	6.48
Maintenance	9.11	9.11	9.11	9.11	13.5	13.5	13.5	13.5
Operating Labour	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Labour Ohd &Supervision	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
Insurance and taxes	7.3	7.3	7.3	7.3	10.8	10.8	10.8	10.8
TOTAL	**152.79**	**284.79**	**86.79**	**152.79**	**166.81**	**298.81**	**100.81**	**166.81**
Calculation Reference	***Run 1***	***Run 3***	***Run 5***	***Run 7***	***Run 2***	***Run 4***	***Run 6***	***Run 8***

CASE 3&4 OPERATING COSTS

SUMMARY OF ANNUAL OPERATING COSTS FOR AN IDEAL YEAR (MMUS$)

	USCPF WITHOUT CO2 CAPTURE(CASE 3)				USCPF WITH CO2 CAPTURE(CASE 4)			
Fuel Price	1.5$/GJ	3$/GJ	0.75 $/GJ	$1.5/GJ	1.5$/GJ	3$/GJ	0.75 $/GJ	$1.5/GJ
Discount rate	**10%**	**10%**	**10%**	**5%**	**10%**	**10%**	**10%**	**5%**
	831 MW GROSS OUTPUT%				**827 MW GROSS OUTPUT**			
Fuel	81.4	162.8	40.71	81.4	90.4	180.8	45.19	90.4
Chemicals and Consumables	6.46	6.46	6.46	6.46	20.49	20.49	20.49	20.49
Maintenance	31.32	31.32	31.32	31.32	37.66	37.66	37.66	37.66
Operating Labour	6.2	6.2	6.2	6.2	6.5	6.5	6.5	6.5
Labour Ohd &Supervision	1.9	1.9	1.9	1.9	2	2	2	2
Insurance and taxes	17.4	17.4	17.4	17.4	21.5	21.5	21.5	21.5
TOTAL	**144.68**	**226.08**	**103.99**	**144.68**	**178.55**	**268.95**	**133.34**	**178.55**
Calculation Reference	***Run 9***	***Run 11***	***Run 13***	***Run 15***	***Run 10***	***Run 12***	***Run 14***	***Run 16***

3.0 Description Of Model

The model used to calculate the cost of production of electricity is an EXCEL spreadsheet based on the IEA GHG model.

The model consists of some input data sheets and a final sheet which performs a cash flow analysis.

Cash flows are determined for each year by ascribing an assumed selling price to the electricity and using this to calculate a sales revenue based on the case parameters specified. Annual operating costs are calculated and a net cash flow calculated as the difference between the sales revenue and the operating costs. The NPV of these cash flows is then adjusted to give a zero value by adjustment of the selling price (using a goal seek command). By definition then, the value of the selling price which gives a zero NPV is the production cost.

In this model the discounting convention is as follows.

a) The model calculates discount factors for each year from the assumed discount rate.

b) It applies each year's discount rate to the appropriate cash flow including the capital spending (negative cash flows) during the construction period.

c) These discounted flows are then netted through the years to give a net discounted project cash flow.

d) The start of the discount is assumed to be the present i.e. it is the start of the construction period (NOT the start of the operating period).

4.0 Results of Simulations

An index of the runs is presented on the following Table G1and the results are summarized on the Table G2 (Results of Economic Analysis Runs). The costs of production are shown graphically on Figs B1 and B2.

Fig B1 is for plants without carbon dioxide capture and Fig B2 is for plants with post combustion carbon dioxide capture.

The breakdown of the operating cost components for an ideal year (365 days) is shown on Table G3, (presented in Section 2.7).

TABLE G1

INDEX OF ECONOMIC ANALYSIS RUNS

run no.	CASE	Discount rate %	Fuel	Price $/GJ	Description
1	1	10	Nat.Gas	3	Base case NGCC no capture
2	2	10	Nat.Gas	3	Base case NGCC with capture
3	1	10	Nat.Gas	6	NGCC without capture +100% fuel price
4	2	10	Nat.Gas	6	NGCC with capture +100% fuel price
5	1	10	Nat.Gas	1.5	NGCC without capture -100% fuel price
6	2	10	Nat.Gas	1.5	NGCC with capture -100% fuel price
7	1	5	Nat.Gas	3	NGCC without capture 5% Discount rate
8	2	5	Nat.Gas	3	NGCC with capture 5% Discount rate
9	3	10	Coal	1.5	Base case USCPF no capture
10	4	10	Coal	1.5	Base Case USCPF with capture
11	3	10	Coal	3	USCPF without capture +100% fuel price
12	4	10	Coal	3	USCPF with capture +100% fuel price
13	3	10	Coal	0.75	USCPF without capture -100% fuel price
14	4	10	Coal	0.75	USCPF without capture -100% fuel price
15	3	5	Coal	1.5	USCPF without capture 5% discount rate
16	4	5	Coal	1.5	USCPF with capture 5% discount rate

TABLE G2: REVISED ECONOMICS SUMMARY

RUN	Discount rate	Plant	CO2 Capture	Fuel Cost	Gross MW	Net MW	Cost of electricity	CO2 Avoidance cost
	%			USD/Gj			cents/kWh	USD/Ton
1	10	NGCC	no	3	800	776	**3.13**	
2	10	NGCC	yes	3	740	662	**4.4**	**39.73**
3	10	NGCC	no	6	800	776	**5.07**	
4	10	NGCC	yes	6	740	662	**6.67**	**51.37**
5	10	NGCC	no	1.5	800	776	**2.16**	
6	10	NGCC	yes	1.5	740	662	**3.26**	**35.36**
7	5	NGCC	no	3	800	776	**2.81**	
8	5	NGCC	yes	3	740	662	**3.86**	**33.28**
9	10	PF	no	1.5	831	758	**4.39**	
10	10	PF	yes	1.5	827	666	**6.24**	**29.49**
11	10	PF	no	3	831	758	**5.62**	
12	10	PF	yes	3	827	666	**7.78**	**39.52**
13	10	PF	no	0.75	831	758	**3.78**	
14	10	PF	yes	0.75	827	666	**5.46**	**26.86**
15	5	PF	no	1.5	831	758	**3.58**	
16	5	PF	yes	1.5	827	666	**5.07**	**23.85**

FIG B1 COST OF GENERATION VERSUS FUEL PRICE

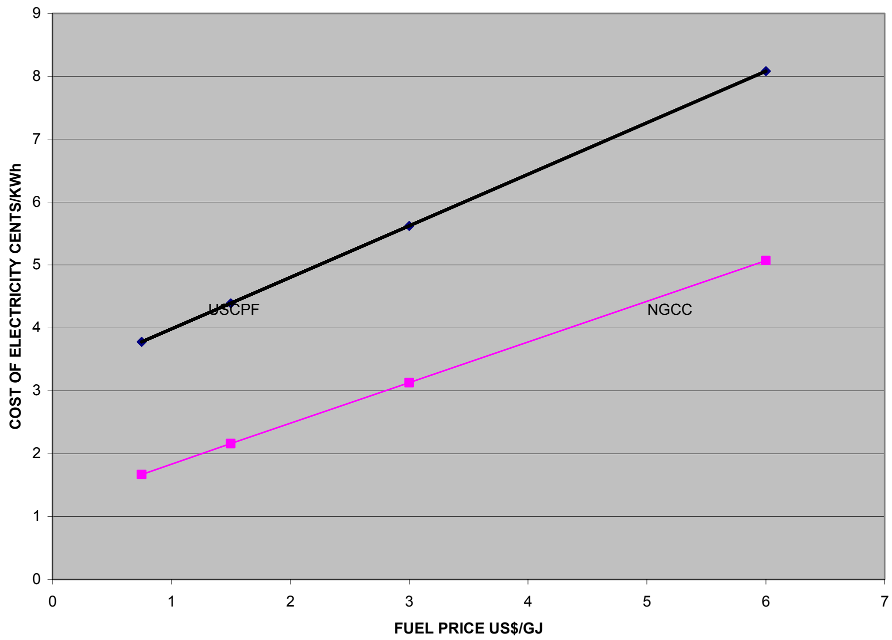
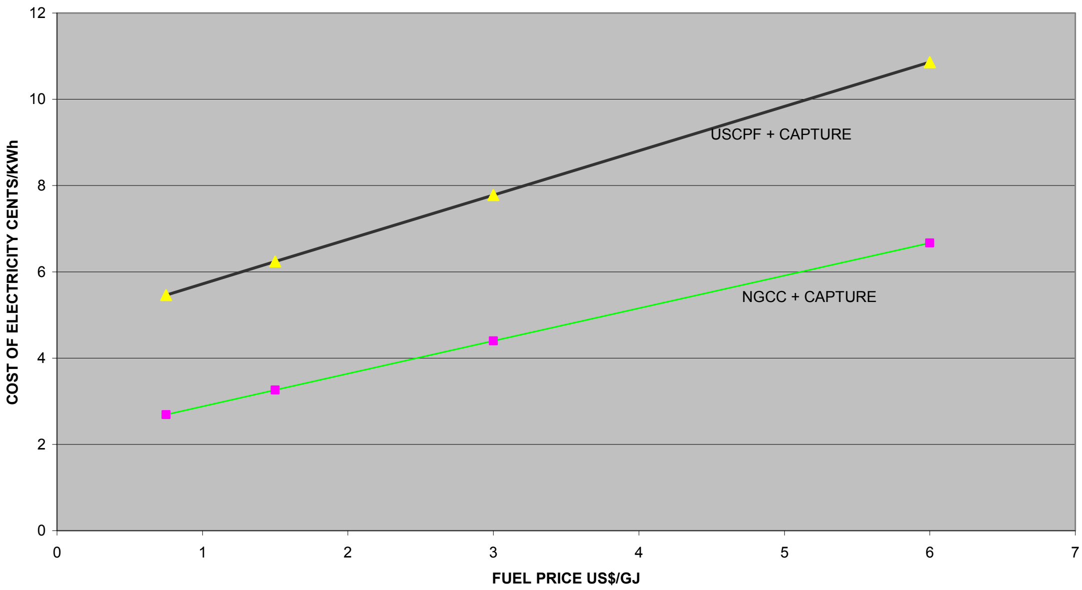


FIG B2 COST OF GENERATION WITH CAPTURE VERSUS FUEL PRICE



These graphs show very clearly that the generation price curves for natural gas combined cycle plants and ultra supercritical fired pulverised coal plants overlap. This means that there is a natural gas/coal price ratio at which the levelised costs of power are the same for both processes. Beyond this point USCPF becomes the cheaper option despite its much higher capital cost.

Thus for the plants without carbon dioxide capture, with a coal price of 1.5 US$/Gj, USCPF is the cheapest generator when gas prices are just under 5 US$/Gj. For plants with carbon dioxide capture, the equivalence occurs just under 5 US$/Gj.

It is quite conceivable that these fuel price ratios will be attained and sustained in the medium term. Thus current US Government data (www.EIA.DOE.gov) shows a coal price projected to 1.3 US$/Gj with an equivalent market point gas price of 4.7US$/Gj. It is quite likely that gas prices will reach higher levels whilst coal prices are expected to remain fairly static. This has clear implications for the selection of appropriate generation technology for new plants especially now that USCPF is a high efficiency clean coal technology.

Cost of avoidance of carbon dioxide emission is approx 40 US$ per tonne for the base case NGCC plant and approx 29.5 US$ per tonne for the USCPF. Care is needed in the interpretation of these numbers since they can only be calculated with any commercial relevance in a particular commercial scenario. These numbers are calculated by comparing the case with capture to that without.

The implication in the calculation of avoidance costs is that the reference plant is a true commercial base case. This is unlikely to be so since a commercial base case may be to not invest in power generation at all. There is in reality no carbon dioxide emission avoidance since all plants which are built will emit CO_2 in varying degrees whether mitigated or not. It does not make sense to quote an avoidance cost which is based on how much worse it might have been if something else (which is hypothetical) had been done.

The true cost of capturing carbon dioxide is to be calculated by comparing costs of electricity generation with and without capture since kWh is the only market product. To date there is no basis for calculating a cost or value of captured carbon dioxide (until, that is, emission trading, emission capping and penalties for overstepping the caps are in vogue and it is then possible to establish a market price for avoided carbon dioxide emissions).

The calculated costs of electricity do not include cost of disposal of capture plant residues nor do they include any credits or costs associated with solid effluents and by product streams from the PF plants.

Currently residues from the only operating small scale amine scrubbing plants are disposed of to specialist waste disposal companies. The costs shown on the cost summaries in this report reflect the relatively high costs of doing this. By the time that large scale capture is implemented on power plants it is probable that a cheaper solution (possibly an in-process treatment step) will have been developed. This will almost certainly be very much cheaper than the current disposal and treatment route. It was considered that the use of the current cost of disposal would therefore be excessive if applied to large scale plants and so these costs have been omitted from this study.

Aqueous stream are assumed to be disposed of by injection into the cooling water flows.

5.0 Economic Analysis Output Sheets

These are appended to this section as follows:-

NGCC Power Plant

- Run Number 1 : NGCC without CO_2 Capture : Base Case
- Run Number 2 : NGCC with CO_2 Capture : Base Case
- Run Number 3 : NGCC without CO_2 Capture : +100% Fuel Price

- Run Number 4 : NGCC with CO_2 Capture : +100% Fuel Price
- Run Number 5 : NGCC without CO_2 Capture : -100% Fuel Price
- Run Number 6 : NGCC with CO_2 Capture : -100% Fuel Price
- Run Number 7 : NGCC without CO_2 Capture : Base Case @ 5% Discount Rate
- Run Number 8 : NGCC with CO_2 Capture : Base Case @ 5% Discount Rate
-

USCPF Power Plant

- Run Number 9 : USCPF without CO_2 Capture : Base Case
- Run Number 10 : USCPF with CO_2 Capture : Base Case
- Run Number 11 : USCPF without CO_2 Capture : +100% Fuel Price
- Run Number 12 : USCPF with CO_2 Capture : +100% Fuel Price
- Run Number 13 : USCPF without CO_2 Capture : -100% Fuel Price
- Run Number 14 : USCPF with CO_2 Capture : -100% Fuel Price
- Run Number 15 : USCPF without CO_2 Capture : Base Case @ 5% Discount Rate
- Run Number 16 : USCPF with CO_2 Capture : Base Case @ 5% Discount Rate

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 1				
Calculated electricity cost			**output**	**31.30**	**$/MWH**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	3	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00005	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Load factor in start up year			input	60	%
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 1**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross power output	input	MW	800
Fuel feedrate	input	MW	1396
Net power output	input	MW	776
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	379
TIC	input	MM$	331
Contingencies	input	MM$	33.4
Owners Cost	input	MM$	23
TOTAL CAPEX			387.4
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	131.92	MM$/YR
MAINTENANCE	output	9.11	MM$/YR
CHEMICALS + CONSUMABLES	output	0.35	MM$/YR
INSURANCE AND TAXES	output	7.29	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) RUN NUMBER 1

YEAR		-2	-1	Ist op year	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
Load Factor				21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor		40.00%	40.00%	20.00%																									
REVENUES																													
Electricity produced (GWH)				1444.524	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	
Electricity sales revenue				45.21	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	180.83	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**45.21**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	**180.83**	
OPERATING COSTS																													
Fuel				28.03	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	
Maintenance				1.94	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	
Labour				4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables				0.07	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	
TOTAL OPERATING COST				**41.36**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	**132.86**	
FIXED CAPITAL EXPENDITURE		-154.96	-154.96	-77.48																									
WORKING CAPITAL				-0.5																									0.5
TOTAL YEARLY CASH FLOW		**-154.96**	**-140.8727**	**-73.13**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**0.5**
Discount factor to get 2004 values		**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE	**-£0.00**	-154.96	-140.8727	-60.4406	36.04445	32.76768	29.7888	27.08073	24.61884	22.38077	20.34615	18.4965	16.815	15.28636	13.8967	12.63336	11.48487	10.44079	9.49163	8.628754	7.844322	7.131202	6.482911	5.893555	5.357778	4.870707	4.427915	4.025378	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
RUN NUMBER 2					
Calculated electricity cost			**output**	**44.03**	**$/MWH**
Calculated emission avoidance cost			**output**	**40.6806**	**$/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	3	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00100	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Load factor in start up year			input	60	%
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	379	g/kWh
Reference Plant Electricity cost	**note 1**		input	3.13	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 2**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross power output	input	MW	740
Fuel feedrate	input	MW	1396
Net power output	input	MW	662
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	66
TIC	input	MM$	491
Contingencies	input	MM$	49
Owners Cost	input	MM$	35
TOTAL CAPEX			575
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	131.92	MM$/YR
MAINTENANCE	output	13.50	MM$/YR
CHEMICALS + CONSUMABLES	output	6.48	MM$/YR
INSURANCE AND TAXES	output	10.80	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 2**

YEAR	**-2**	**-1**	**Ist op year**	**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**
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	40.00%	40.00%	20.00%																									
REVENUES																												
Electricity produced (GWH)			1232.313	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	
Electricity sales revenue			54.26	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	217.05	
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE			**54.26**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	**217.05**	
OPERATING COSTS																												
Fuel			28.03	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	
Maintenance			2.87	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables			1.38	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes			10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	
TOTAL OPERATING COST			**47.11**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	
FIXED CAPITAL EXPENDITURE	-230	-230	-115																									
WORKING CAPITAL			-0.5																									0.5
TOTAL YEARLY CASH FLOW	**-230**	**-230**	**-107.35**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**0.5**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE **-£0.00**	-230	-209.0909	-88.7167	53.40057	48.54597	44.1327	40.12064	36.47331	33.15755	30.14323	27.40293	24.91176	22.64705	20.58823	18.71657	17.01507	15.46824	14.06204	12.78367	11.62152	10.56502	9.604561	8.73142	7.937654	7.216049	6.560045	5.963677	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 3				
Calculated electricity cost			**output**	**50.70**	**$/MWH**
Discount rate			input	10	%
Load Factor			input	85	%
Fuel Price			input	6	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00005	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR [note1] **RUN NUMBER 3**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	800
Fuel feedrate	input	MW	1396
Net power output	input	MW	776
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	379
TIC	input	MM$	331
Contingencies	input	MM$	33.4
Owners Cost	input	MM$	23
TOTAL CAPEX			387.4
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	263.84	MM$/YR
MAINTENANCE	output	9.11	MM$/YR
CHEMICALS + CONSUMABLES	output	0.35	MM$/YR
INSURANCE AND TAXES	output	7.29	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) RUN NUMBER 3

YEAR	-2	-1	Ist op year	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
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	40.00%	40.00%	20.00%																									
REVENUES																												
Electricity produced (GWH)			1444.524	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	
Electricity sales revenue			73.24	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	292.97	
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE			**73.24**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	**292.97**	
OPERATING COSTS																												
Fuel			56.07	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	
Maintenance			1.94	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables			0.07	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes			7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	
TOTAL OPERATING COST			**69.40**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	**244.99**	
FIXED CAPITAL EXPENDITURE	-154.96	-154.96	-77.48																									
WORKING CAPITAL			-0.5																									0.5
TOTAL YEARLY CASH FLOW			**-73.13**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**0.5**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE **-£0.00**	-154.96	-140.8727	-60.4406	36.04445	32.76768	29.7888	27.08073	24.61884	22.38077	20.34615	18.4965	16.815	15.28636	13.8967	12.63336	11.48487	10.44079	9.49163	8.628754	7.844322	7.131202	6.482911	5.893555	5.357778	4.870707	4.427915	4.025378	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 4				
Calculated electricity cost			**output**	**66.78**	**$/MWH**
Calculated emission avoidance cost			**output**	**51.37908**	**$/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	6	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00100	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Load factor in start up year			input	60	%
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	379	g/kWh
Reference Plant Electricity cost	**note 1**		input	5.07	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 4**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	740
Fuel feedrate	input	MW	1396
Net power output	input	MW	662
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kwh	66
TIC	input	MM$	491
Contingencies	input	MM$	49
Owners Cost	input	MM$	35
TOTAL CAPEX			575
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	263.84	MM$/YR
MAINTENANCE	output	13.50	MM$/YR
CHEMICALS + CONSUMABLES	output	6.48	MM$/YR
INSURANCE AND TAXES	output	10.80	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 4**

YEAR	-2	-1	Ist op year	2	3	4	5	6	7	8	9	10
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expenditure factor	40.00%	40.00%	20.00%									
REVENUES												
Electricity produced (GWH)			1232.313	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252
Electricity sales revenue			82.30	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE			**82.30**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**
OPERATING COSTS												
Fuel			56.07	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27
Maintenance			2.87	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Chemicals & Consumables			1.38	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance and local taxes			10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
TOTAL OPERATING COST			**75.14**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**
FIXED CAPITAL EXPENDITURE	-230	-230	-115									
WORKING CAPITAL			-0.5									
TOTAL YEARLY CASH FLOW			**-107.35**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**
NET PRESENT VALUE -£0.00	-230	-209.0909	-88.7167	53.40057	48.54597	44.1327	40.12064	36.47331	33.15755	30.14323	27.40293	24.91176

YEAR	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor																
REVENUES																
Electricity produced (GWH)	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	
Electricity sales revenue	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	329.18	
By-product sales revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	**329.18**	
OPERATING COSTS																
Fuel	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	224.27	
Maintenance	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	
Labour	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	
Waste Disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	
TOTAL OPERATING COST	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	**258.11**	
FIXED CAPITAL EXPENDITURE																
WORKING CAPITAL																0.5
TOTAL YEARLY CASH FLOW	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**0.5**
Discount factor to get 2004 values	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE	22.64705	20.58823	18.71657	17.01507	15.46824	14.06204	12.78367	11.62152	10.56502	9.604561	8.73142	7.937654	7.216049	6.560045	5.963677	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 5				
Calculated electricity cost			**output**	**21.59**	**$/MWH**
Discount rate			input	10	%
Load Factor			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00005	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kwh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 5**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	800
Fuel feedrate	input	MW	1396
Net power output	input	MW	776
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	379
TIC	input	MM$	331
Contingencies	input	MM$	33.4
Owners Cost	input	MM$	23
TOTAL CAPEX			387.4
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	65.96	MM$/YR
MAINTENANCE	output	9.11	MM$/YR
CHEMICALS + CONSUMABLES	output	0.35	MM$/YR
INSURANCE AND TAXES	output	7.29	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 5**

YEAR	-2	-1	Ist op year	2	3	4	5	6	7	8	9	10
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expenditure factor	40.00%	40.00%	20.00%									
REVENUES												
Electricity produced (GWH)			1444.524	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096
Electricity sales revenue			31.19	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE			**31.19**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**
OPERATING COSTS												
Fuel			14.02	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07
Maintenance			1.94	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Chemicals & Consumables			0.07	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance and local taxes			7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29
TOTAL OPERATING COST			**27.35**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**
FIXED CAPITAL EXPENDITURE	-154.96	-154.96	-77.48									
WORKING CAPITAL			-0.5									
TOTAL YEARLY CASH FLOW			**-73.13**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**
NET PRESENT VALUE -£0.00	-154.96	-140.8727	-60.4406	36.04445	32.76768	29.7888	27.08073	24.61884	22.38077	20.34615	18.4965	16.815

YEAR	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor																
REVENUES																
Electricity produced (GWH)	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	
Electricity sales revenue	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	124.77	
By-product sales revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	**124.77**	
OPERATING COSTS																
Fuel	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	
Maintenance	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	
Labour	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	
Waste Disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	
TOTAL OPERATING COST	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	**76.79**	
FIXED CAPITAL EXPENDITURE																
WORKING CAPITAL																0.5
TOTAL YEARLY CASH FLOW	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**47.98**	**0.5**
Discount factor to get 2004 values	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE	15.28636	13.8967	12.63336	11.48487	10.44079	9.49163	8.628754	7.844322	7.131202	6.482911	5.893555	5.357778	4.870707	4.427915	4.025378	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
RUN NUMBER 6					
Calculated electricity cost			**output**	**32.66**	**$/MWH**
Calculated emission avoidance cost			**output**	**35.36331**	**$/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00100	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Load factor in start up year			input	60	%
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	379	g/kWh
Reference Plant Electricity cost	**note 1**		input	2.159	C/kwh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR [note1] **RUN NUMBER 6**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	740
Fuel feedrate	input	MW	1396
Net power output	input	MW	662
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kwh	66
TIC	input	MM$	491
Contingencies	input	MM$	49
Owners Cost	input	MM$	35
TOTAL CAPEX			575
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	65.96	MM$/YR
MAINTENANCE	output	13.50	MM$/YR
CHEMICALS + CONSUMABLES	output	6.48	MM$/YR
INSURANCE AND TAXES	output	10.80	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 6**

YEAR	-2	-1	Ist op year	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
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	40.00%	40.00%	20.00%																									
REVENUES																												
Electricity produced (GWH)			1232.313	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	
Electricity sales revenue			40.25	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	160.98	
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE			**40.25**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	**160.98**	
OPERATING COSTS																												
Fuel			14.02	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	56.07	
Maintenance			2.87	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables			1.38	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes			10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	
TOTAL OPERATING COST			**33.09**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	**89.91**	
FIXED CAPITAL EXPENDITURE	-230	-230	-115																									
WORKING CAPITAL			-0.5																									0.5
TOTAL YEARLY CASH FLOW			**-107.35**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**71.08**	**0.5**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE **£0.00**	-230	-209.0909	-88.7167	53.40057	48.54597	44.1327	40.12064	36.47331	33.15755	30.14323	27.40293	24.91176	22.64705	20.58823	18.71657	17.01507	15.46824	14.06204	12.78367	11.62152	10.56502	9.604561	8.73142	7.937654	7.216049	6.560045	5.963677	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 7				
Calculated electricity cost			**output**	**28.15**	**$/MWH**
Discount rate			input	5	%
Load Factor years 2-25			input	85	%
Fuel Price			input	3	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00005	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Load factor in start up year			input	60	%
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kwh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 7**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	800
Fuel feedrate	input	MW	1396
Net power output	input	MW	776
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	379
TIC	input	MM$	331
Contingencies	input	MM$	33.4
Owners Cost	input	MM$	23
TOTAL CAPEX			387.4
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	131.92	MM$/YR
MAINTENANCE	output	9.11	MM$/YR
CHEMICALS + CONSUMABLES	output	0.34	MM$/YR
INSURANCE AND TAXES	output	7.29	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $)

RUN NUMBER 7

YEAR	-2	-1	Ist op year	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
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	40.00%	40.00%	20.00%																									
REVENUES																												
Electricity produced (GWH)			1444.524	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	5778.096	
Electricity sales revenue			40.66	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	162.64	
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE			**40.66**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	**162.64**	
OPERATING COSTS																												
Fuel			28.03	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	
Maintenance			1.94	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	9.11	
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables			0.07	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes			7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	7.29	
TOTAL OPERATING COST			**41.36**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	**132.85**	
FIXED CAPITAL EXPENDITURE	-154.96	-154.96	-77.48																									
WORKING CAPITAL			-0.5																									0.5
TOTAL YEARLY CASH FLOW			**-77.68**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**29.79**	**0.5**
Discount factor to get 2004 values	**1.00**	**0.95**	**0.91**	**0.86**	**0.82**	**0.78**	**0.75**	**0.71**	**0.68**	**0.64**	**0.61**	**0.58**	**0.56**	**0.53**	**0.51**	**0.48**	**0.46**	**0.44**	**0.42**	**0.40**	**0.38**	**0.36**	**0.34**	**0.33**	**0.31**	**0.30**	**0.28**	**0.27**
NET PRESENT VALUE **£0.00**	-154.96	-147.581	-70.4571	25.73505	24.50957	23.34245	22.2309	21.17229	20.16408	19.20389	18.28942	17.41849	16.58904	15.79909	15.04675	14.33024	13.64785	12.99795	12.379	11.78952	11.22812	10.69344	10.18423	9.699269	9.237399	8.797523	8.378594	0.133924

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
RUN NUMBER 8					
Calculated electricity cost			**output**	**38.57**	**$/MWH**
Calculated emission avoidance cost			**output**	**33.28294**	**$/Tonne CO2**
Discount rate			input	5	%
Load Factor years 2-25			input	85	%
Fuel Price			input	3	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.00100	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
Load factor in start up year			input	60	%
Capital expenditure phasing			input		
			input		
		Year 1	input	40	%
		Year 2	input	40	%
		Year 3	input	20	%
			input		
Reference Plant CO2 emissions	**note 1**		input	379	g/kWh
Reference Plant Electricity cost	**note 1**		input	2.815	C/kwh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 8**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	740
Fuel feedrate	input	MW	1396
Net power output	input	MW	662
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/KWH	0
Liquid wastes output	input	Tonnes/KWH	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kwh	66
TIC	input	MM$	491
Contingencies	input	MM$	49
Owners Cost	input	MM$	35
TOTAL CAPEX			575
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	131.92	MM$/YR
MAINTENANCE	output	13.50	MM$/YR
CHEMICALS + CONSUMABLES	output	6.48	MM$/YR
INSURANCE AND TAXES	output	10.80	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $)

RUN NUMBER 8

YEAR	**-2**	**-1**	**Ist op year**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expenditure factor	40.00%	40.00%	20.00%										
REVENUES													
Electricity produced (GWH)			1232.313	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252
Electricity sales revenue			47.53	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE			**47.53**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**
OPERATING COSTS													
Fuel			28.03	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13
Maintenance			2.87	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03
Chemicals & Consumables			1.38	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance and local taxes			10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
TOTAL OPERATING COST			**47.11**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**
FIXED CAPITAL EXPENDITURE	-230	-230	-115										
WORKING CAPITAL			-0.5										
TOTAL YEARLY CASH FLOW			**-114.08**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**
Discount factor to get 2004 values	**1.00**	**0.95**	**0.91**	**0.86**	**0.82**	**0.78**	**0.75**	**0.71**	**0.68**	**0.64**	**0.61**	**0.58**	**0.56**
NET PRESENT VALUE **£0.00**	-230	-219.0476	-103.476	38.12589	36.31037	34.58131	32.93458	31.36626	29.87263	28.45013	27.09536	25.8051	24.57629

YEAR	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor															
REVENUES															
Electricity produced (GWH)	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	4929.252	
Electricity sales revenue	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	190.11	
By-product sales revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	**190.11**	
OPERATING COSTS															
Fuel	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	
Maintenance	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	
Labour	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	5.51	
Waste Disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80	
TOTAL OPERATING COST	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	**145.97**	
FIXED CAPITAL EXPENDITURE															
WORKING CAPITAL															0.5
TOTAL YEARLY CASH FLOW	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**44.14**	**0.5**
Discount factor to get 2004 values	**0.53**	**0.51**	**0.48**	**0.46**	**0.44**	**0.42**	**0.40**	**0.38**	**0.36**	**0.34**	**0.33**	**0.31**	**0.30**	**0.28**	**0.27**
NET PRESENT VALUE **£0.00**	23.40599	22.29142	21.22992	20.21897	19.25617	18.33921	17.46591	16.6342	15.84209	15.08771	14.36925	13.685	13.03333	12.4127	0.133924

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 9				
Calculated electricity cost			**output**	**43.90**	**$/MWH**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.000887	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kwh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 9**

ITEM	Type	UNITS	VALUE
Number of operators	input		124
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power output	input	MW	831
Fuel feedrate	input	MW	1723
Net power output	input	MW	758
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	743
TIC	input	MM$	791
Contingencies	input	MM$	79
Owners Cost	input	MM$	56
TOTAL CAPEX			926
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.6

Calculated Operating costs at 100% output

FUEL	output	81.41	MM$/YR
MAINTENANCE	output	31.32	MM$/YR
CHEMICALS + CONSUMABLES	output	6.46	MM$/YR
INSURANCE AND TAXES	output	17.40	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.20	MM$/YR
LABOUR OHD + SUPERVISION	output	1.86	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) RUN NUMBER 9

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				2988.036	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	
Electricity sales revenue				131.19	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	247.80	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**131.19**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	**247.80**	
OPERATING COSTS																													
Fuel				36.64	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	
Maintenance				14.09	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	
Labour				8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	
Chemicals & Consumables				2.91	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	
TOTAL OPERATING COST				**79.10**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	
FIXED CAPITAL EXPENDITURE	-185.2	-416.7	-324.1																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW		**-416.7**	**-324.1**	**61.19**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	**-£0.00**	-378.8181818	-267.8512	45.97441	79.45428	72.23116	65.66469	59.69517	54.26834	49.33486	44.84987	40.77261	37.06601	33.69637	30.63306	27.84824	25.31658	23.01507	20.92279	19.02072	17.29157	15.71961	14.29055	12.99141	11.81037	10.7367	9.760638	8.873307	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 10				
Calculated electricity cost			**output**	**62.36**	**$/MWH**
Calculated emission avoidance cost			**output**	**29.49**	**$/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.002829	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	743	g/kWh
Reference Plant Electricity cost	**note 1**		input	4.39	C/kwh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 10**

ITEM	Type	UNITS	VALUE
Number of operators	input		130
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	827
Fuel feedrate	input	MW	1913
Net power output	input	MW	666
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	117
TIC	input	MM$	998
Contingencies	input	MM$	100
Owners Cost	input	MM$	70
TOTAL CAPEX			1168
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.43

Calculated Operating costs at 100% output

FUEL	output	90.39	MM$/YR
MAINTENANCE	output	37.66	MM$/YR
CHEMICALS + CONSUMABLES	output	20.49	MM$/YR
INSURANCE AND TAXES	output	21.96	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.50	MM$/YR
LABOUR OHD + SUPERVISION	output	1.95	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 10**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expenditure factor	20.00%	45.00%	35.00%											
REVENUES														
Electricity produced (GWH)				2625.372	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036
Electricity sales revenue				163.72	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE				**163.72**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**
OPERATING COSTS														
Fuel				40.68	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83
Maintenance				16.95	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66
Labour				8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45
Chemicals & Consumables				9.22	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance and local taxes				21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96
TOTAL OPERATING COST				**97.26**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**
FIXED CAPITAL EXPENDITURE	-233.6	-525.6	-408.8											
WORKING CAPITAL				-9.1										
TOTAL YEARLY CASH FLOW		**-525.6**	**-408.8**	**75.57**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**
NET PRESENT VALUE	**£0.00**	-477.8181818	-337.8512	56.77612	100.3582	91.23475	82.94068	75.40062	68.54602	62.31456	56.6496	51.49964	46.81785	42.56169

YEAR	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor															
REVENUES															
Electricity produced (GWH)	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	
Electricity sales revenue	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	309.26	
By-product sales revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	**309.26**	
OPERATING COSTS															
Fuel	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	
Maintenance	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	
Labour	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	
Chemicals & Consumables	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	
Waste Disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	
TOTAL OPERATING COST	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	
FIXED CAPITAL EXPENDITURE															
WORKING CAPITAL															9.1
TOTAL YEARLY CASH FLOW	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**9.1**
Discount factor to get 2004 values	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	38.69244	35.17495	31.97722	29.0702	26.42746	24.02496	21.84087	19.85534	18.05031	16.40937	14.91761	13.56146	12.3286	11.20782	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

		TYPE	VALUE	UNITS
RUN NUMBER 11				
Calculated electricity cost		**output**	**56.16**	**$/MWH**
Discount rate		input	10	%
Load Factor years 2-25		input	85	%
Fuel Price		input	3	$/GJ
By-product price		input	0	$/Tonne
Solid Waste Disposal Cost		input	0	$/Tonne
Liquid waste Disposal Cost		input	0	$/tonne
Amine unit Waste Disposal Cost		input	0	$/Tonne
Chemical and consumable cost		input	0.000887	$/kWh
Insurance and local taxes		input	2	% Capex
Startup time		input	3	months
		input		%
Capital expenditure phasing		input		
		input		
	Year 1	input	20	%
	Year 2	input	45	%
	Year 3	input	35	%
		input		
Reference Plant CO2 emissions	**note 1**	input	0	g/kWh
Reference Plant Electricity cost	**note 1**	input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 11**

ITEM	Type	UNITS	VALUE
Number of operators	input		124
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	831
Fuel feedrate	input	MW	1723
Net power output	input	MW	758
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kwh	743
TIC	input	MM$	791
Contingencies	input	MM$	79
Owners Cost	input	MM$	56
TOTAL CAPEX			926
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.6

Calculated Operating costs at 100% output

FUEL	output	162.82	MM$/YR
MAINTENANCE	output	31.32	MM$/YR
CHEMICALS + CONSUMABLES	output	6.46	MM$/YR
INSURANCE AND TAXES	output	17.40	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.20	MM$/YR
LABOUR OHD + SUPERVISION	output	1.86	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $

RUN NUMBER 11

YEAR	**2004 -2**	**2005 -1**	**2006 0**	**2007 1**	**2008 2**	**2009 3**	**2010 4**	**2011 5**	**2012 6**	**2013 7**	**2014 8**	**2015 9**	**2016 10**	**2017 11**	**2018 12**	**2019 13**	**2020 14**	**2021 15**	**2022 16**	**2023 17**	**2024 18**	**2025 19**	**2026 20**	**2027 21**	**2028 22**	**2029 23**	**2030 24**	**2031 25**	**2032 26**
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				2988.036	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	
Electricity sales revenue				167.82	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	317.00	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**167.82**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	**317.00**	
OPERATING COSTS																													
Fuel				73.27	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	138.40	
Maintenance				14.09	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	
Labour				8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	
Chemicals & Consumables				2.91	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	
TOTAL OPERATING COST				**115.73**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	**200.67**	
FIXED CAPITAL EXPENDITURE	-185.2	-416.7	-324.1																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW		**-416.7**	**-324.1**	**61.19**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	**£0.00**	-378.82	-267.85	45.97462	79.45464	72.23149	65.66499	59.69544	54.26858	49.33508	44.85007	40.77279	37.06617	33.69652	30.6332	27.84836	25.3167	23.01518	20.92289	19.02081	17.29164	15.71968	14.29061	12.99147	11.81043	10.73675	9.760682	8.873347	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cos

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
RUN NUMBER 12					
Calculated electricity cost			**output**	**77.86**	**$/MWH**
Calculated emission avoidance cost			**output**	**39.52**	**$/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	3	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.002829	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	666	g/kWh
Reference Plant Electricity cost	**note 1**		input	5.616	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 12**

ITEM	Type	UNITS	VALUE
Number of operators	input		130
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	827
Fuel feedrate	input	MW	1913
Net power output	input	MW	666
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	117
TIC	input	MM$	998
Contingencies	input	MM$	100
Owners Cost	input	MM$	70
TOTAL CAPEX			1168
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.43

Calculated Operating costs at 100% output

FUEL	output	180.78	MM$/YR
MAINTENANCE	output	37.66	MM$/YR
CHEMICALS + CONSUMABLES	output	20.49	MM$/YR
INSURANCE AND TAXES	output	21.96	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.50	MM$/YR
LABOUR OHD + SUPERVISION	output	1.95	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 12**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				2625.372	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	
Electricity sales revenue				204.40	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	386.09	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**204.40**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	**386.09**	
OPERATING COSTS																													
Fuel				81.35	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	153.66	
Maintenance				16.95	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	
Labour				8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	
Chemicals & Consumables				9.22	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	
TOTAL OPERATING COST				**137.93**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	**239.15**	
FIXED CAPITAL EXPENDITURE	-233.6	-525.6	-408.8																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW		**-525.6**	**-408.8**	**75.57**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	**£0.00**	-477.8181818	-337.8512	56.77612	100.3582	91.23475	82.94068	75.40062	68.54602	62.31456	56.6496	51.49964	46.81785	42.56169	38.69244	35.17495	31.97722	29.0702	26.42746	24.02496	21.84087	19.85534	18.05031	16.40937	14.91761	13.56146	12.3286	11.20782	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 13				
Calculated electricity cost			**output**	**37.77**	**$/MWH**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	0.75	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.000887	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 13**

ITEM	Type	UNITS	VALUE
Number of operators	input		124
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	831
Fuel feedrate	input	MW	1723
Net power output	input	MW	758
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kwh	743
TIC	input	MM$	791
Contingencies	input	MM$	79
Owners Cost	input	MM$	56
TOTAL CAPEX			926
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.6

Calculated Operating costs at 100% output

FUEL	output	40.71	MM$/YR
MAINTENANCE	output	31.32	MM$/YR
CHEMICALS + CONSUMABLES	output	6.46	MM$/YR
INSURANCE AND TAXES	output	17.40	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.20	MM$/YR
LABOUR OHD + SUPERVISION	output	1.86	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 13**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expenditure factor	20.00%	45.00%	35.00%											
REVENUES														
Electricity produced (GWH)				2988.036	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068
Electricity sales revenue				112.87	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE				**112.87**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**
OPERATING COSTS														
Fuel				18.32	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60
Maintenance				14.09	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32
Labour				8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06
Chemicals & Consumables				2.91	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance and local taxes				17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40
TOTAL OPERATING COST				**60.78**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**
FIXED CAPITAL EXPENDITURE	-185.2	-416.7	-324.1											
WORKING CAPITAL				-9.1										
TOTAL YEARLY CASH FLOW	**-185.2**	**-416.7**	**-324.1**	**61.19**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**
NET PRESENT VALUE	**£0.00**	-378.8181818	-267.8512	45.97441	79.45428	72.23116	65.66469	59.69517	54.26834	49.33486	44.84987	40.77261	37.06601	33.69637

YEAR	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor															
REVENUES															
Electricity produced (GWH)	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	
Electricity sales revenue	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	213.20	
By-product sales revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	**213.20**	
OPERATING COSTS															
Fuel	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	
Maintenance	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	
Labour	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	
Chemicals & Consumables	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	
Waste Disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	
TOTAL OPERATING COST	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	**96.87**	
FIXED CAPITAL EXPENDITURE															
WORKING CAPITAL															9.1
TOTAL YEARLY CASH FLOW	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**116.33**	**9.1**
Discount factor to get 2004 values	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	30.63306	27.84824	25.31658	23.01507	20.92279	19.02072	17.29157	15.71961	14.29055	12.99141	11.81037	10.7367	9.760638	8.873307	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
RUN NUMBER 14					
Calculated electricity cost			**output**	**54.62**	**$/MWH**
Calculated emission avoidance cost			**output**	**26.86**	**$/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	0.75	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.002829	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	743	g/kWh
Reference Plant Electricity cost	**note 1**		input	3.78	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR note1 **RUN NUMBER 14**

ITEM	Type	UNITS	VALUE
Number of operators	input		130
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	827
Fuel feedrate	input	MW	1913
Net power output	input	MW	666
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	117
TIC	input	MM$	998
Contingencies	input	MM$	100
Owners Cost	input	MM$	70
TOTAL CAPEX			1168
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.43

Calculated Operating costs at 100% output

FUEL	output	45.19	MM$/YR
MAINTENANCE	output	37.66	MM$/YR
CHEMICALS + CONSUMABLES	output	20.49	MM$/YR
INSURANCE AND TAXES	output	21.96	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.50	MM$/YR
LABOUR OHD + SUPERVISION	output	1.95	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 14**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				2625.372	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	
Electricity sales revenue				143.39	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	270.84	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**143.39**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	**270.84**	
OPERATING COSTS																													
Fuel				20.34	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	38.42	
Maintenance				16.95	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	
Labour				8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	
Chemicals & Consumables				9.22	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	
TOTAL OPERATING COST				**76.92**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	**123.91**	
FIXED CAPITAL EXPENDITURE	-233.6	-525.6	-408.8																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW		**-525.6**	**-408.8**	**75.57**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**146.93**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	**-£0.00**	-477.8181818	-337.8512	56.77612	100.3582	91.23475	82.94068	75.40062	68.54602	62.31456	56.6496	51.49964	46.81785	42.56169	38.69244	35.17495	31.97722	29.0702	26.42746	24.02496	21.84087	19.85534	18.05031	16.40937	14.91761	13.56146	12.3286	11.20782	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 15				
Calculated electricity cost			**output**	**35.81**	**$/MWH**
Discount rate			input	5	%
Load Factor years 2-25			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.000887	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	0	g/kWh
Reference Plant Electricity cost	**note 1**		input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR [note1] **RUN NUMBER 15**

ITEM	Type	UNITS	VALUE
Number of operators	input		124
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	831
Fuel feedrate	input	MW	1723
Net power output	input	MW	758
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	743
TIC	input	MM$	791
Contingencies	input	MM$	79
Owners Cost	input	MM$	56
TOTAL CAPEX			926
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.6

Calculated Operating costs at 100% output

FUEL	output	81.41	MM$/YR
MAINTENANCE	output	31.32	MM$/YR
CHEMICALS + CONSUMABLES	output	6.46	MM$/YR
INSURANCE AND TAXES	output	17.40	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.20	MM$/YR
LABOUR OHD + SUPERVISION	output	1.86	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 15**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				2988.036	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	5644.068	
Electricity sales revenue				106.99	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	202.09	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**106.99**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	**202.09**	
OPERATING COSTS																													
Fuel				36.64	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	
Maintenance				14.09	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	31.32	
Labour				8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	
Chemicals & Consumables				2.91	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	5.49	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	
TOTAL OPERATING COST				**79.10**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	**131.47**	
FIXED CAPITAL EXPENDITURE	-185.2	-416.7	-324.1																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW		**-416.7**	**-324.1**	**36.99**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**70.62**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.95**	**0.91**	**0.86**	**0.82**	**0.78**	**0.75**	**0.71**	**0.68**	**0.64**	**0.61**	**0.58**	**0.56**	**0.53**	**0.51**	**0.48**	**0.46**	**0.44**	**0.42**	**0.40**	**0.38**	**0.36**	**0.34**	**0.33**	**0.31**	**0.30**	**0.28**	**0.27**	**0.26**
NET PRESENT VALUE	**-£0.00**	-396.8571429	-293.9683	31.95499	58.09744	55.3309	52.69609	50.18675	47.79691	45.52086	43.3532	41.28877	39.32263	37.45013	35.66679	33.96837	32.35083	30.81031	29.34316	27.94586	26.61511	25.34772	24.14069	22.99113	21.89631	20.85363	19.8606	18.91486	2.321352

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
	RUN NUMBER 16				
Calculated electricity cost			**output**	**50.73**	**$/MWH**
Calculated emission avoidance cost			**output**	**23.85**	**$/Tonne CO2**
Discount rate			input	5	%
Load Factor years 2-25			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.002829	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	743	g/kWh
Reference Plant Electricity cost	**note 1**		input	3.58	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR [note1] **RUN NUMBER 16**

ITEM	Type	UNITS	VALUE
Number of operators	input		130
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	827
Fuel feedrate	input	MW	1913
Net power output	input	MW	666
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	117
TIC	input	MM$	998
Contingencies	input	MM$	100
Owners Cost	input	MM$	70
TOTAL CAPEX			1168
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.43

Calculated Operating costs at 100% output

FUEL	output	90.39	MM$/YR
MAINTENANCE	output	37.66	MM$/YR
CHEMICALS + CONSUMABLES	output	20.49	MM$/YR
INSURANCE AND TAXES	output	21.96	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.50	MM$/YR
LABOUR OHD + SUPERVISION	output	1.95	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 16**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor				45.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				2625.372	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	4959.036	
Electricity sales revenue				133.18	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	251.57	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**133.18**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	**251.57**	
OPERATING COSTS																													
Fuel				40.68	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	
Maintenance				16.95	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	37.66	
Labour				8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	
Chemicals & Consumables				9.22	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	17.42	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	21.96	
TOTAL OPERATING COST				**97.26**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	**162.32**	
FIXED CAPITAL EXPENDITURE	-233.6	-525.6	-408.8																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW		**-525.6**	**-408.8**	**45.03**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**89.24**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.95**	**0.91**	**0.86**	**0.82**	**0.78**	**0.75**	**0.71**	**0.68**	**0.64**	**0.61**	**0.58**	**0.56**	**0.53**	**0.51**	**0.48**	**0.46**	**0.44**	**0.42**	**0.40**	**0.38**	**0.36**	**0.34**	**0.33**	**0.31**	**0.30**	**0.28**	**0.27**	**0.26**
NET PRESENT VALUE	**-£0.00**	-500.5714286	-370.7937	38.89521	73.41982	69.92364	66.59394	63.4228	60.40267	57.52635	54.787	52.1781	49.69343	47.32707	45.0734	42.92705	40.8829	38.9361	37.082	35.31619	33.63447	32.03283	30.50745	29.05472	27.67116	26.35348	25.09856	23.90339	2.321352

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

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SECTION H

COST SENSITIVITIES

1.0 Capital Cost Sensitivity

The capital cost of the power plant is a significant contribution to the levelised cost of electricity production.

To explore this sensitivity a series of runs have been made which investigate a plus/minus twenty percentage point change in the capital cost estimates.

Output for these runs is given at the end of this section and costs are summarised as follows in cents/kWh:-

	BASE	-20% Capex	+20% Capex
NGCC/No capture	3.13	2.9	3.35
NGCC/With capture	4.4	4.01	4.8
USCPF/No capture	4.39	3.8	4.9
USCPF/With capture	6.23	5.3	6.4

2.0 Use Of H Type Turbines

2.1 Introduction

The General Electric H technology combined cycle plants can achieve approximately 60% net thermal efficiency in a single shaft gas turbine/steam turbine combination. The turbines are steam cooled and the steam cooling loop is integrated with the HRSG.

A three pressure reheat steam cycle is used. Cooling steam for the gas turbine front staging is supplied by the IP superheater supported as necessary with HP steam turbine exhaust. Steam is delivered to the gas turbine stationary parts through casing connections and to the rotor via conventional glands. This cooling steam is returned to the steam cycle at the cold reheat line. The return steam and any HP steam turbine exhaust not used for gas turbine cooling are reheated in the HRSG and admitted to the IP steam turbine.

The turbine is capable of operating at higher firing temperatures which produces dramatic improvement in fuel efficiency. In the 9FA turbines used as the base case for this study, the first stage nozzle is cooled with compressor discharge air. This cooling process causes a temperature drop. In the H turbine the steam cooling avoids this air temperature drop leading to more efficient power extraction.

The H turbine and its integration into its HRSG is described fully in GE publications GER-3936A and GER-3935B available on the GE power web site.

This sensitivity study is based on simulations of the H system using GTPRO which has the operating characteristics in its data base.

The increased capital cost of this system has been estimated by comparing the simulation outputs for the H cases with those of the 9FA base cases and the capital costs ratioed according to the ratios of those outputs.

2.2 Results

Two new cases (CASE 5 without CO_2 capture and CASE 6 with CO_2 capture) are defined and the relevant data follows. In addition sensitivity runs have been made using the economic model and the output from these runs is given at the end of this section.

2.3 Discussion

The data show that use of the new GE 9H gas turbine and associated combined cycle HRSG and steam turbine combination gives positive benefit. Use of this technology results in larger gross power outputs than is the case for 9FA turbines. The gross efficiency for the non capture case rises from 57.3% LHV to 59.9% LHV although levelised COE remains close to 3.1 cents/kWh . The cost of the GE9H plant is much greater than the 9FA plant (505MM USD cf 388 MM USD reflecting the greater capacity) and there is a scale effect since the larger plant achieves the same unit cost of electricity as the smaller plant and it is slightly more efficient

CASE 5 CAPITAL COST ESTIMATE

All costs in Millions of dollars

DESCRIPTION		1000 power	2000 CO2	3000 CO2 comp	4000 Balance of plant	TOTAL
Equipment cost		176.69			8.47	
Installation factor		1.53			1.61	
Bldgs and electrical equipment		0.00			14.30	
Infrastructure (blgs + electrical)					42.99	
DIRECT FIELD COST (DFC)		**270.33**			**70.93**	**341.26**
	%DFC					
Construction management	2	5.41			1.42	6.83
Commissioning	2	5.41			1.42	6.83
Commissioning spares	0.5	1.35			0.35	1.71
Temporary facilities	5	13.52			3.55	17.06
Vendor reps attendance		1.00			0.00	1.00
Heavy lifts		1.00			0.00	1.00
Freight, taxes &insurance	1	2.70			0.71	3.41
INDIRECT FIELD COSTS		**30.38**			**7.45**	**37.83**
ENGINEERING COSTS	**12**	**32.44**			**8.51**	**40.95**
TOTAL INSTALLED COST		**333.16**			**86.89**	**420.05**
CONTINGENCY	**10**	**33.32**			**8.69**	**42.00**
License fees						
Owners costs	10	33.32			8.69	42.00
OVERALL PROJECT COST		**399.79**			**104.27**	**504.06**

CHEMICALS AND CONSUMABLES SUMMARY

CASE 5: FRAME 9 H NGCC WITHOUT CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	1016	
Net Power output	MW	986	
CO2 emission	Tonnes/Hr	357.3	351.7 g/kWh
CO2 Recovered			
Fuel Feedrate			
Coal			
Natural gas	Tones/Hr	130.25	
Chemicals and consumables			
Make-up water	Tonnes/Hr	5.43	
Limestone			
Ammonia			
MEA solvent			
Amine inhibitors			
Miscellaneous	$/MWh	0.05	
Catalyst for DENOX			
Waste Disposal			
Bottom ash			
Fly ash			
Gypsum			
Chloride			
Amine unit waste			
Waste water	Tonnes/Hr	5.43	HRSG Blowdown
Number of operators		62	

CASE 6 CAPITAL COST ESTIMATE

All costs in Millions of dollars

DESCRIPTION		1001 power	2000 CO2	3000 CO2 comp	4001 Balance Of Plant	TOTAL
Equipment cost		176.69	52.00	15.70	13.00	
Installation factor		1.53	2.60	1.78	1.61	
Bldgs and electrical equipment		0.00			20.35	
Infrastructure(bldgs+electrical)					42.99	
DIRECT FIELD COST (DFC)		**270.34**	**135.20**	**27.95**	**84.27**	**517.75**
	%DFC					
Construction management	2	5.41	2.70	0.56	1.69	10.36
Commissioning	2	5.41	2.70	0.56	1.69	10.36
Commissioning spares	0.5	1.35	0.68	0.14	0.42	2.59
Temporary facilities	5	13.52	6.76	1.40	4.21	25.89
Vendor reps attendance		1.00	1.00	1.00	0.00	3.00
Heavy lifts		1.00	1.00		0.00	2.00
Freight, taxes &insurance	1	2.70	1.35	0.28	0.84	5.18
INDIRECT FIELD COSTS		**30.39**	**16.20**	**3.93**	**8.85**	**59.36**
ENGINEERING COSTS	**12**	**32.44**	**16.22**	**3.35**	**10.11**	**62.13**
TOTAL INSTALLED COST		**333.16**	**167.62**	**35.23**	**103.23**	**639.25**
CONTINGENCY	**10**	**33.32**	**16.76**	**3.52**	**10.32**	**63.92**
License fees						
Owners costs	10	33.32	16.76	3.52	10.32	63.92
OVERALL PROJECT COST		**399.79**	**201.14**	**42.28**	**123.88**	**767.09**

CHEMICALS AND CONSUMABLES SUMMARY

CASE 6: FRAME 9 H NGCC WITH CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	990	
Net Power output	MW	896	
CO2 emission	Tonnes/Hr	357.3	361g/kWh reduced to 54 g/kWh
CO2 Recovered			
Fuel Feedrate			
Coal			
Natural gas	Tones/Hr	130.25	
Chemicals and consumables			
Make-up water	Tonnes/Hr	5.43	
Limestone			
Ammonia			
MEA solvent	Kg/Ton CO2	1.6	1300 US$/ton
Amine inhibitors	US$/Ton CO2	0.53	
Activated carbon	Kg/Ton CO2	0.06	1000 US$/ton
Sod Ash	Kg/Ton CO2	0.13	110US$/ton CO2
Miscellaneous	$/MWh	0.05	Allowance
Catalyst for DENOX			
Waste Disposal			
Bottom ash			
Fly ash			
Gypsum			
Chloride			
Amine unit waste	Ton/Ton co2	0.0032	
Waste water	Tonnes/Hr	5.43	HRSG Blowdown
Number of operators		68	

3.0 Sensitivity to CO_2 Capture Percentage

As the carbon dioxide capture percentage increases additional packing is required in the EFG absorbers. Since there is a maximum allowable height for each packed section of the absorber (based on hydraulic and pressure drop constraints) a point is reached at which an additional packed bed is required. There is then a substantial capital cost increment for a small increase in CO2 recovery since the new packed column section requires support, column shell and liquid distribution arrangements.

The current designs are based on an 85% recovery for the NGCC plant and 87.5% fro the PF fired[plants. These levels are close to the break point for needing additional packed sections in the column. Without a specified economic context it is not possible to determine the optimal level of recovery, since it requires knowledge of market prices for electricity and a value for recovered carbon dioxide, but it will lie somewhere in the 85% to 95% range.

If carbon emissions penalties and taxes were in force, for example, it would probably be close to 95% for a supercritical coal fired plant. Studies have shown that at 85% recovery the cost of electricity is reduced by about 5% compared with 95% recovery but the cost of capture increases by about 2% (Ref 1). This shows that the optimization criteria are crucial and that a price for carbon dioxide avoidance is necessary to answer the optimization question.

REFS

1. **Application of the Econamine FG Plus(sm) process to Canadian coal based power plant** by Shakir Khambaty, Satish Reddy and Robert Stobbs presented at Clean Coal Session of Combustion Canada Conference, Vancouver, Canada September 22-24, 2003.

4.0 Sensitivity to Carbon Dioxide Purity

Because the EFG+ process uses a chemical reaction to recover carbon dioxide there is a very high selectivity for the carbon dioxide. At the partial pressures of the contaminants prevailing in the flue gas there is very little absorption of species other than CO_2. Other acid gas constituents react with the alkaline amine and form heat stable salts which do not desorb when stripped. This is in contrast to physical solvent absorption processes which operate at very high species partial pressures.

Thus there is very little change in achieved carbon dioxide purity with wide ranges of change in process variables. The net result is that the process always produces very high specifications of recovered carbon dioxide which in some cases is usable as a food grade product without additional treatment.

As mentioned above acid gas impurities report as heat stable salts which are removed from the system and do not influence recovered CO_2 purity. The purity limit is finally set by the solubility of nitrogen and oxygen in the circulating amine solution so the limit on this is set by the solubility of these gases at the striper bottoms temperature. An extremely small quantity of NO (which is non reactive) will end up in the product gas.

In summary CO_2 purity is not an optimisable variable.

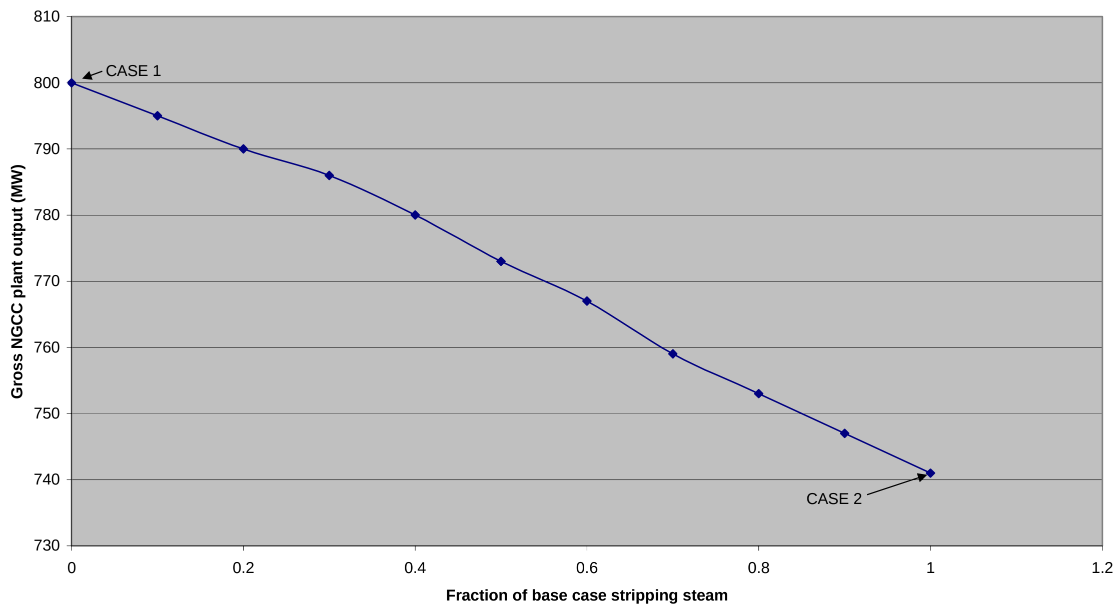
5.0 Sensitivity to Amine Unit Stripping Steam Rate

Sensitivity calculations show that an as yet undiscovered solvent with a 50% lower stripping steam requirement than that of the base case (MEA solvent used in the EFG+ configuration) saves about 0.22 cents/kWh of generation cost. This is equivalent to a 2.3% gain in net cycle efficiency which is of course well worth having.

This is based on constant capital expenditure from one sensitivity case point to another and takes no account of the likely high cost of such a solvent nor the changed mass transfer efficiencies and reaction kinetics which might pertain with its use (MEA by way of contrast is a cheap, bulk produced petrochemical commodity with good reactivity and mass transfer characteristics).

These sensitivity simulations can be used to define stretch targets for amine developments. Thus, Fig B3 shows the effects of amine stripping energy improvement on gross power output in an NGCC integrated with amine capture.

FIG B3 Gross Power output versus Stripping steam fraction



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SECTION J

POTENTIAL TECHNOLOGY STRETCH TO 2020

1.0 Introduction

The remaining sections of the report present an analysis of potential improvements in solvent scrubbing CO_2 capture between now and 2020. Combustion power generation processes are also expected to improve between now and 2020 and these improvements will almost certainly contribute to an overall improvement in post combustion carbon dioxide capture economics. These expected improvements are also analysed and quantified. The list of references at the end of this Section contains back ground discussion material on various aspects of likely improvements and developments in these technologies

Additional cases, based on this data, are presented which assess the overall performance and costs of power stations (with and without carbon dioxide capture) which could be built in 2020 and incorporating the identified improvement features.

Simplified road maps are presented which identify how the identified improvements could be developed and commercialised.

2.0 Potential Improvements in Solvent Scrubbing Technology

2.1 Capital Cost Components for the Current Design

Amongst currently available technologies, gas absorption using amines is considered to be the most cost effective for the large scale post combustion capture of carbon dioxide. However, the amine systems used at the low partial pressure conditions encountered with carbon dioxide in flue gases have inherent disadvantages; viz:-

- High heat of reaction which leads to the need for expensive cooling systems.
- High regeneration energy needs which requires large quantities of low pressure steam and correspondingly large stripper column reboilers.
- The need for large absorbers with expensive packings to provide adequate mass transfer surface for the carbon dioxide absorption and reaction.
- The need to circulate large quantities of amines because of practical limitation of carbon dioxide loadings.

- A high parasitic power loss caused by the need to overcome the pressure drops in the large absorbers.

These factors combine to result in relatively high capital costs for the capture plant and high operating costs and consequential efficiency losses in host power plants when the capture plant is integrated.

Table J1 shows a breakdown of capital costs for the capture plants designed for CASES 2 and 4 in this study, i.e; 2004 design plants for use on NGCC and USCPF power stations.

TABLE J1: NGCC AND PF CO2 CAPTURE PLANTS DIRECT FIELD COST

ITEM	NGCC		PF	
	MMUS$	% of total	MMUS$	%of total
Gas cooling	12.00	10.5%	6.00	4.8%
Absorbers	39.00	34.2%	39.00	31.2%
Stripper	6.00	5.3%	6.00	4.8%
Reboiler	5.00	4.4%	8.00	6.4%
Condenser	1.00	0.9%	2.00	1.6%
Coolers	2.00	1.8%	2.00	1.6%
Solvent HE	2.00	1.8%	4.00	3.2%
Vessels	1.00	0.9%	1.00	0.8%
Blowers	7.00	6.1%	5.00	4.0%
Pumps	12.00	10.5%	10.00	8.0%
Misc equipment packages	2.00	1.8%	2.00	1.6%
CO2 compression	25.00	21.9%	40.00	32.0%
DIRECT FIELD COST	**114**	100%	**125**	100.0%

It can be seen from Table J1 that in terms of capital cost the most significant items are absorption equipment, carbon dioxide compression and solvent recovery.

There are also high operating costs (in terms of required energy consumption) associated with this capital. Thus the absorption step requires that the flue gas is cooled (needing extra equipment) and compressed via the blowers to overcome the pressure loss associated with the absorber packing. A much larger energy loss is associated with the solvent recovery systems reboilers.

Thus it is to be expected that any achievable reductions in these capital costs will also be reflected in lower energy consumption for the process. This can also be stated the other way around viz: it is to be expected that lower energy consumptions will result in lower capital costs as the two cost components (CAPEX plus OPEX are strongly interrelated).

2.2 Potential Capital Cost reductions for the 2020 Carbon Dioxide Capture Plant

A capital cost estimate for a projected 2020 plant is presented on Table J2. This estimate assumes that process development will continue on amine scrubbing processes and that the following improvements could be made.

It must be emphasized that these estimates are guesses based on engineering judgements.

Although amine scrubbing technology for carbon dioxide recovery is very mature, there are as yet no very large scale plants in operation and there is therefore very limited data on what these plants, if built today, would cost. This means that most of the designs of the postulated large scale plants have yet to be verified (even though the technology and process modeling capabilities are on a very solid basis)via construction and operation. It is very probable, therefore, that current design margins could be reduced if there were a competitive market in which operators and technology licensors were designing , building and constructing these plants. The following guessed reductions will therefore probably be made by a combination of cost lowering via design optimization in a competitive market (which as yet does not exist) plus technology developments ,viz; new amines by way of example

- **Removal of the need for gas cooling in the PF fired plant**. This assumes that the amine scrubbing plant will be integrated with the FGD plant (which is required for PF fired plants and not required for NGCC plants) and that the FGD plant will be designed to operate with a 50 degree C outlet temperature. In the case of NGCC plants, the cooling systems upstream of the amine scrubbers will still be required.

- **Optimisation of the design of the absorbers** to increase mass transfer efficiency, reduce packing volumes, pressure drop, blower costs and power consumption. It is also conceivable that concrete towers might be used in place of the current steel towers. A 25% cost reduction is targetted with a 50% reduction in blower costs.

- **Solvent developments which lead to a reduction in the consumption of stripping steam** in the amine regeneration sections of the plant:-This will result in a smaller reboiler and a reduced need for steam extraction from the power cycle. The reduction in reboiler costs will be proportional to the reduction in stripping steam, assumed to be in the region of 30% although it is difficult to place any certainty on this figure.

- **Solvent developments which allow an increased carbon dioxide loading of the solvent**:- The aim of this would be to reduce the amine circulation rates and reduce pumping costs. A 30% reduction in solvent circulation has been postulated as a consequence of increasing the amine loading, either by development of new additives or developments in amine formulations.

- **Optimisation of the design of the carbon dioxide compression** and drying systems which lead to substantial reductions in capital cost and the possibility of recovering more compression heat (possibly as LP steam):- This will require developments in compressor seal temperature tolerance to allow operation at higher compression ratios and at higher compressor stage outlet temperatures. Although gas compression is a very mature chemical engineering unit operation, there are no commercial carbon dioxide and integrated drying sytems in operation at anything like the capacity required for post combustion carbon dioxide capture. For this reason (a lack of design optimization in the "paper" studies done to date) a fairly optimistic assumption has been made that the capital costs of the compressors, carbon dioxide dryer and associated heat recovery systems will drop by as much as 50%

TABLE J2: 2020 NGCC AND PF CO2 CAPTURE PLANTS DIRECT FIELD COST IN MMUS$

ITEM	NGCC 2004	PF 2004	Postulated Reduction	NGCC 2020	PF 2020	Reason For Reduction
Gas cooling	12.00	6.00	0	12	0	Integrate gas cooling into FGD at no cost
Absorbers	39.00	39.00	25%	29.25	29.25	Improve mass transfer
Stripper	6.00	6.00	25%	4.5	4.5	Reduced steam with improved solvent
Reboiler	5.00	8.00	30%	3.5	5.6	Reduced stripping steam
Condenser	1.00	2.00	0	1	2	
Coolers	2.00	2.00	30%	1.4	1.4	Higher CO2 loading
Solvent HE	2.00	4.00	30%	1.4	2.8	Higher CO2 loading
Vessels	1.00	1.00	0	1	1	
Blowers	7.00	5.00	50%	3.5	2.5	Lower pressure drops plus optimisation
Pumps	12.00	10.00	50%	6	5	Optimised design
Misc equipment packages	2.00	2.00	0	2	2	
CO2 compression	25.00	40.00	50%	12.5	20	Optimised design
DIRECT FIELD COST	**114**	**125**		**78**	**76**	
Percentage of of 2004 COST				**68.46%**	**60.84%**	

Application of these reduction factors to the 2004 capital cost breakdown yields the estimated 2020 plant cost. The resultant capital cost of the capture plant plus carbon dioxide compression and drying (see Section K) is 60-70% of that of the 2004 plant as a result of the postulated developments.

2.3 Potential Operating Cost Reductions for the 2020 Plant

These are given and discussed in full in Section L of this report which presents the economics of the 2020 power plants. However in summary, the savings in operating costs which would accrue from the solvent scrubbing developments discussed are as follows:

- The assumed 30% reduction in stripping steam results in an increased power output from the integrated carbon dioxide capture plant and its associated power plant. Additional power is generated since less steam is extracted from the turbines and this extra steam is then expanded through the LP sections of the turbines to produce more power. In the case of the 2020 NGCC plant with integrated capture plant the extra output achieved by a 30% stripping steam saving is about 20MWe and the case of the PF plant this increases to 40MWe (because of the correspondingly greater amount of un-extracted steam expanded through the turbine).

- There is a reduction in parasitic power losses in the 2020 capture plant because of the postulated reduction in pressure drops and the resulting lower required blower power and the reduced circulating volume of amine requiring slightly less pump power. This amounts to a saving of 11MWe for the NGCC case and 10MWe for the PF case.

Other non-capital related operating costs have been assumed to remain constant despite the postulated improvements in amines. This is tantamount to saying that amine consumptions and cost will remain constant between now and 2020.

3.0 Potential Improvements in Supercritical PF-Fired Power Station Technology

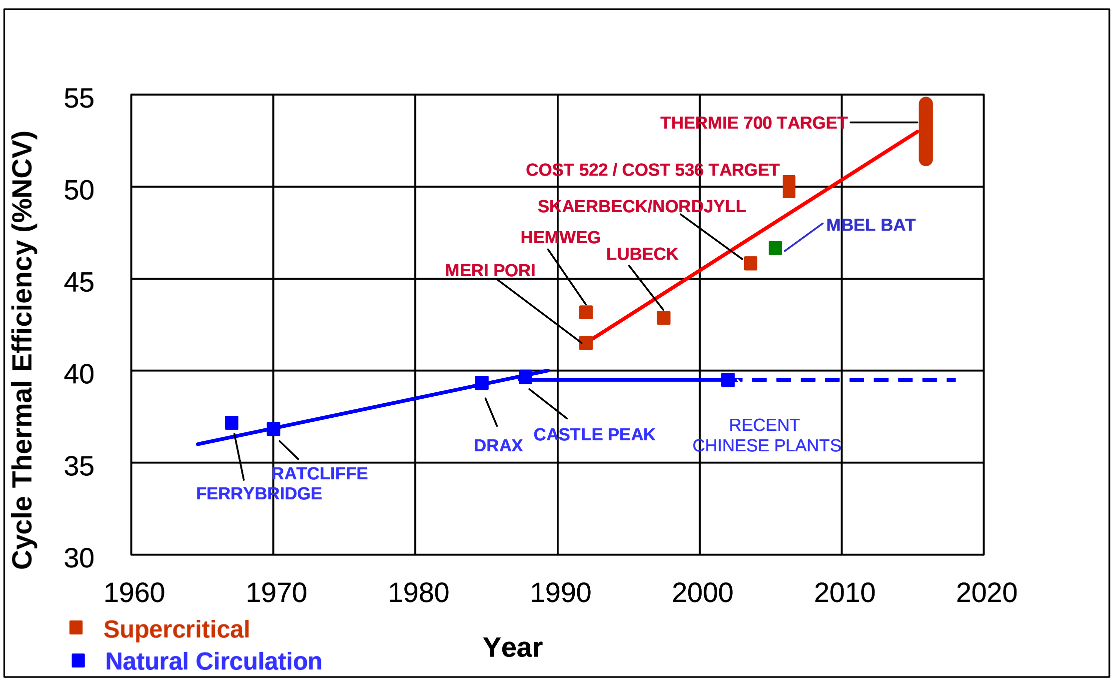
3.1 Current state-of-the-art

Most of the current generation of PF fired power plants are sub-critical and work well below the critical pressure of water at 221.2 bara. Over the past few decades advances have been made in the development of supercritical designs. These with their higher operating temperatures achieve a higher thermodynamic efficiency than sub-critical plants. Although these supercritical plants represent the current state-of-the-art, they are not being used in more than about 10% of new orders for power plant, but are now being increasingly adopted in developing countries such as China. For example, in 2003 China ordered in excess of 100GWe of PF power plants, Mitsui Babcock had a significant share- (approx 13%) of the boilers for this market, with all 13.8GWe being supercritical boilers)

Despite this, developments are under way to increase operating pressures, and therefore temperatures, to higher levels. These projected developments are shown on Fig J1 which also shows the developmental history from sub-critical to supercritical designs. It can be seen from this data that sub-critical plants have peaked at about 40% efficiency without much expected improvement from that level.

The upper curve on Fig J1 shows supercritical plant efficiencies with the current best available technology (from Mitsui Babcock in this case) achieving efficiencies in the 45% + region (in this study the base case PF plant achieves a 44% net efficiency on an LHV basis). The final steam conditions are 290 bara / 600 degrees C / 620 degrees C.

Fig J1: Development of Thermal Efficiency in Coal Fired Power Plants



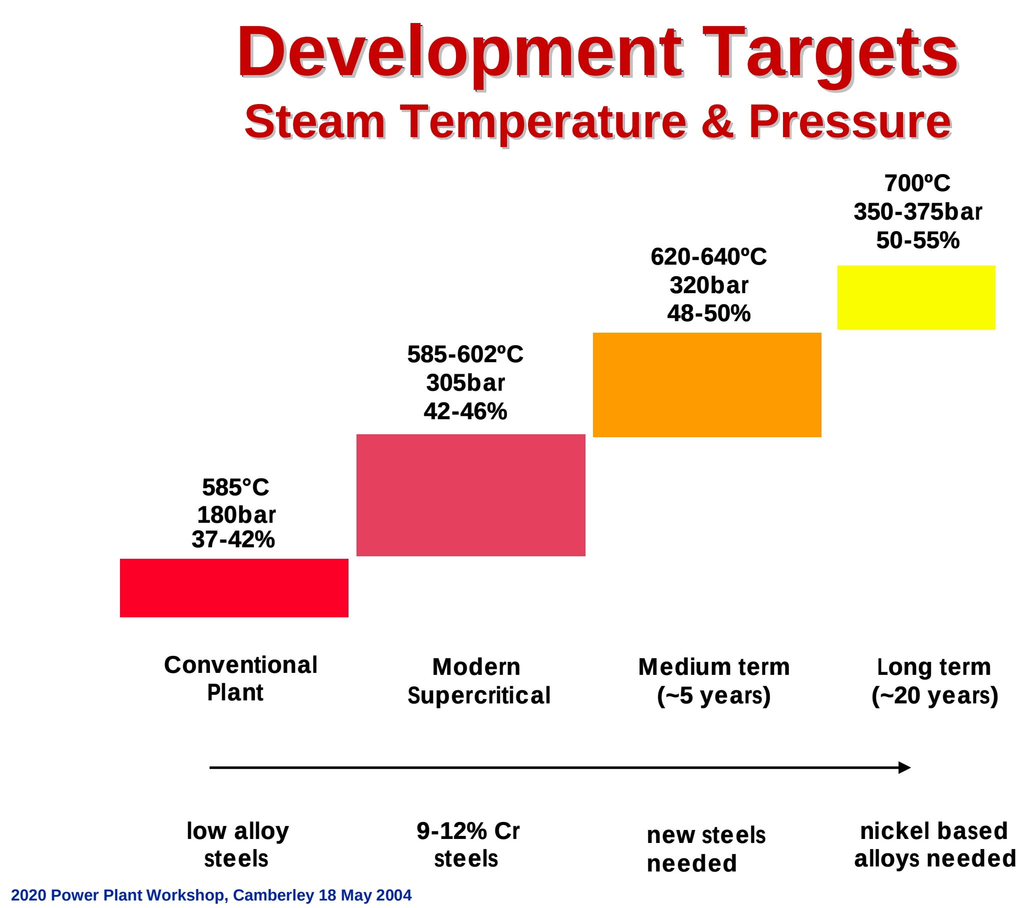
3.2 Industry development programmes

International R&D programmes are in place which continue to develop the supercritical technology. Because of the steam conditions and high resulting steam temperatures, materials development is required. There are a number of international programmes which have the aim of developing materials and power plant designs which exploit them to achieve very high operating pressures and temperatures.

The probable end point of this development will be the advanced 700 degrees C power plant which results in efficiencies of greater than 50%. The development targets for this are shown on Fig J2.

From the current state-of-the-art we may expect 320bara/620-640 Deg C by 2010 with 48-50% efficiencies and 350-375 bara/700 Deg C by 2025 with efficiencies in the range 50-55% with capital cost reductions (see Section K below) and operating cost reductions (described in Section L).

FIG J2



4.0 Potential Improvements in NG fired Combined Cycle Power Station Technology

4.1 Current state-of-the-art

In a gas turbine powered combined cycle power station, the design of the steam system is governed by the way in which the HRSG extracts heat from the gas turbine exhaust gases and the development of the HRSG is strongly linked to advances in gas turbine design. To date the supercritical HRSG has not been used and this limits the ultimate efficiency which can be achieved. However even sub-critical HRSG designs result in high efficiencies (compared with PF fired power stations). For example the base case design in this report achieves a 55% LHV net efficiency (without carbon dioxide capture) with GE Frame 9F gas turbines.

With the GE H technology, combined cycle plants can achieve approximately 60% LHV net thermal efficiency in a single shaft gas turbine/steam turbine combination. The turbines are steam cooled and the steam cooling loop is integrated with the HRSG.

A three pressure reheat steam cycle is used. Cooling steam for the gas turbine front staging is supplied by the IP superheater supported as necessary with HP steam turbine exhaust. Steam is delivered to the gas turbine stationary parts through casing connections and to the rotor via conventional glands. This cooling steam is returned to the steam cycle at the cold reheat line. The return steam and any HP steam turbine exhaust not used for gas turbine cooling are reheated in the HRSG and admitted to the IP steam turbine.

The turbine is capable of operating at higher firing temperatures which produces dramatic improvement in fuel efficiency. In the 9FA turbines used as the base case for this study, the first stage nozzle is cooled with compressor discharge air. This cooling process causes a temperature drop. In the H turbine the steam cooling avoids this air temperature drop leading to more efficient power extraction.

The H turbine and its integration into its HRSG is described fully in GE publications GER-3936A and GER-3935B available on the GE power web site and currently represents the state of the art for commercially available CCGT plants.

4.1 Expected developments in CCGT technology

As the existing trends in gas turbine size continue, higher exhaust gas temperatures will prevail and the use of the supercritical, once through design of HRSGs becomes feasible. Designs for these are currently in development and the indication is that this will lead to commercial designs for once through supercritical HRSG designs. This will allow the use of higher steam temperatures and should result in higher overall efficiencies for the CCGT cycle. Perhaps efficiencies in the range 60-65% may be expected and more compact designs will lead to capital cost reductions as discussed in Section K below.

5.0 Definitions Of Expected 2020 Plants

5.1 Definition of 2020 plant cases

Based on the descriptions of expected developments in technology a further four cases have been defined. These are described below (cost and economic data is presented in Sections K & L) and summarized on Table L1

- **Case 7** 2020 NGCC plant without carbon dioxide capture
- **Case 8** 2020 NGCC plant with carbon dioxide capture
- **Case 9** 2020 USCPF plant without carbon dioxide capture
- **Case 10** 2020 USCPF plant with carbon dioxide capture

5.2 Definition of CASE 7

This NGCC plant is assumed to benefit from incremental efficiency improvements to a type 9FA turbine resulting in an estimated gross efficiency of say, 63% (LHV)/Net 61.32%(LHV).

This is expected to be achieved by the development of once through super-critical HRSG designs, operating with gas inlet temperatures above 600 degrees C and of compact design which will lead to lower capital costs (see Section K).

It is to be expected that the output of the future derivatives of the Type 9FA will in fact be increased by 2020 but by how much is impossible to determine. For CASES 7&8 we have ignored this factor and assumed that they will be fired at the same rate as that of CASES 1&2 so as to maintain a fair comparison basis.

5.3 Definition of CASE 8

This is as per CASE 7 with the addition of a carbon dioxide capture plant with features as follows:

- Optimised and compact design of the absorbers to increase mass transfer efficiency, reduce packing volumes, pressure drop, blower costs and power consumption. It is also conceivable that concrete towers might be used in place of the current steel towers.

- Solvent developments which lead to a reduction in the consumption of stripping steam in the amine regeneration sections of the plant.

- Solvent developments which allow a reduction in solvent circulation as a consequence of increasing the amine loading.

- Optimisation of the design of the carbon dioxide compression and drying systems

It achieves a gross efficiency of 60% (LHV)/Net 55.37% (LHV)

5.4 Definition of CASE 9

This power plant is assumed to achieve an overall gross efficiency 53%.(LHV)/Net 48.73%(LHV) It is based on an advanced supercritical steam cycle with steam pressures in the 350-375 bara range at temperatures around 700 degrees C. The cycle will be a single reheat with sea water cooling.

The plant will have all of the supporting technology features to achieve these conditions, namely:

- New nickel based super alloys

- New fabrication techniques to allow use of these materials in association with existing materials

- Compact designs which minimize steam piping runs

- Selective catalytic reduction for NOx reduction and state-of-the-art FGD processing

5.5 Definition of CASE 10

This power plant is assumed to achieve an overall gross efficiency of 48%(LHV)/Net40.23%(LHV). It is based on an advanced supercritical steam cycle with steam pressures in the 350-375 bara range at temperatures around 700 degrees C. The cycle will be a single reheat with sea water cooling.

The plant will have all of the supporting technology features to achieve these conditions, namely:

- New nickel based super alloys

- New fabrication techniques to allow use of these materials in association with existing materials

- Compact designs which minimize steam piping runs

In order to allow use of an amine based carbon dioxide capture process (which is assumed to still be the technology of choice in 2020), selective catalytic reduction for NOx reduction and improved flue gas desulphurization will be fitted. This will achieve less than 10 ppmv of sulphur dioxide at the inlet to the carbon dioxide capture plant and will be integrated with the capture plant so that no pre cooling of the flue gas is required prior to the CO_2 absorption towers. In addition the capture process will have the following features (as discussed in Section 2.2 above):-

- Optimised and compact design of the absorbers to increase mass transfer efficiency and reduce packing volumes and pressure drop and blower costs and power consumption. It is also conceivable that concrete towers might be used in place of the current steel towers.

- Solvent developments which lead to a reduction in the consumption of stripping steam in the amine regeneration sections of the plant.

- Solvent developments which allow a reduction in solvent circulation as a consequence of increasing the amine loading.

- Optimisation of the design of the carbon dioxide compression and drying systems with recovery of more compression heat (possibly as LP steam).

<u>REFS</u>

[1] Potential for improvements in gasification combined cycle power generation with CO_2 capture; *IEA Greenhouse Gas R&D programme report PH/19*, published by IEA GHG Programme , Cheltenham, UK May 2003

[2] Kjaer, S et al. The advanced Supercritical 700 ^{o}C Pulverised Coal-fired Power Plant, *VGB Power Tech 7/2002,47-49,* English version published by Technischevereinigang der grosskraftwerksbetreibere.V, Germany, ISSN number 0800-1013.

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[4] Alain, B.,Bengtsson, S. Forsgren, K. Maripuu,M. Nolin,K., New Scrubber Design for Wet FGD Applications; Paper presented at POWER-GEN EUROPE 2004, May, 25-27,2004, Barcelona, Spain,. Proceedings published by Penwell Corporation, Tulsa, Oklahoma, USA.

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SECTION K COST ESTIMATES FOR PROJECTED 2020 CASES

1.0 Introduction

This section summarises the cost estimating methodology used in preparing the case study capital cost estimates shown on Tables K 1-4 for the 2020 power plants.

2.0 Estimate Basis

The same basic data has been used as for Cases 1-4 and the estimate structure is the same as that used for Cases 1-4.

2.1 Overall project Cost

These have been estimated by applying the percentage changes estimated to arise from technology improvement as discussed in Section J. The capital costs for Cases 1-4 on Tables F1-4 have then been reduced by use of a multiplier applied to each plant area using the appropriate percentage factor. Thus the 2020 costs which are shown on Tables K1-4 below are factored from the 2004 costs.

It is to be noted that these cost extrapolations to 2020 are highly uncertain for the obvious reason that we are attempting to guess the state of development in technology in 15 years time. The estimates represent the opinions of the study authors in Fluor, Mitsui Babcock and Alstom

3.0 Estimate Summary Sheets

These are shown on the summary excel spread sheets (Tables K 1-4 for Cases 7-10) which are self explanatory.

- Table K1 : CASE 7 : 2020 NGCC without carbon dioxide capture
- Table K2 : CASE 8 : 2020 NGCC with carbon dioxide capture
- Table K3 : CASE 9 : 2020 USCPF without carbon dioxide capture
- Table K4 : CASE 10 : 2020 USCPF with carbon dioxide capture

TABLE K 1

All costs in Millions of dollars **CASE 7 2020 NGCC without carbon dioxide capture**

% of 2004 cost **80%**

DESCRIPTION		1000 power	2000 CO2	3000 CO2 comp	4000 Balance of plant	TOTAL
Equipment cost		104.00			7.37	
Installation factor		1.53			1.61	
Bldgs and electrical equipment		0.00			14.30	
Infrastructure (blgs + electrical)					42.99	
DIRECT FIELD COST (DFC)		**159.00**			**69.00**	**228.00**
	%DFC					
Construction management	2	3.18			1.38	4.56
Commissioning	2	3.18			1.38	4.56
Commissioning spares	0.5	0.80			0.35	1.14
Temporary facilities	5	7.95			3.45	11.40
Vendor reps attendance		1.00			0.00	1.00
Heavy lifts		1.00			0.00	1.00
Freight, taxes &insurance	1	1.59			0.69	2.28
INDIRECT FIELD COSTS		**18.70**			**7.00**	**25.70**
ENGINEERING COSTS	**12**	**19.08**			**8.00**	**27.08**
TOTAL INSTALLED COST		**196.78**			**84.00**	**280.78**
CONTINGENCY	**10**	**20.00**			**8.40**	**28.40**
License fees						
Owners costs	7	13.77			5.88	19.65
OVERALL PROJECT COST		**231**			**98**	**329**

TABLE K 2

All costs in Millions of dollars **CASE 8 2020 NGCC With carbon dioxide capture**

% of 2004 cost		**80%**	**74%**	**50%**	**100%**	
DESCRIPTION		**1001 power**	**2000 CO2**	**3000 CO2 comp**	**4001 Balance Of Plant**	**TOTAL**
Equipment cost		104.00	25.60	7.00	11.25	
Installation factor		1.53	2.60	1.78	1.61	
Bldgs and electrical equipment		0.00			20.35	
Infrastructure(bldgs+electrical)					42.99	
DIRECT FIELD COST (DFC)		**159**	**67**	**13**	**82**	**321**
	%DFC					
Construction management	2	3.18	1.34	0.25	1.64	6.41
Commissioning	2	3.18	1.34	0.25	1.64	6.41
Commissioning spares	0.5	0.80	0.34	0.06	0.41	1.60
Temporary facilities	5	7.95	3.35	0.63	4.10	16.03
Vendor reps attendance		1.00	1.00	1.00	0.00	3.00
Heavy lifts		1.00	1.00		0.00	2.00
Freight, taxes &insurance	1	1.59	0.67	0.13	0.82	3.21
INDIRECT FIELD COSTS		**19**	**9**	**2**	**9**	**39**
ENGINEERING COSTS	**12**	**19**	**8**	**2**	**10**	**38**
TOTAL INSTALLED COST		**197**	**84**	**16**	**100**	**398**
CONTINGENCY	**10**	**20**	**8**	**2**	**10**	**40**
License fees						
Owners costs	7	13.77	5.89	1.14	7.03	27.83
OVERALL PROJECT COST		**230**	**98**	**19**	**118**	**465**

TABLE K 3

All costs in Millions of dollars **CASE 9** **2020 USCPF without carbon dioxide capture**

DESCRIPTION		100 Coal/Ash Handling	200 Boiler Island	300 FGD	400 DeNox	500 steam turbines	600 CO2 capture	700 CO2 Comp Drying	800 BOP	TOTAL
% of 2004 cost		**80%**	**80%**	**80%**	**100%**	**80%**			**100%**	
Direct Materials		28.00	104.00		12.00	70.00			125.00	
Construction		12.00	72.00	**see below**	3.00	28.00			40.00	
DIRECT FIELD COST (DFC)		**40.00**	**176.00**	**58.00**	**15.00**	**98.00**			**165.00**	**552.00**
	%DFC									
Construction management	2	0.80	3.52	1.16	0.30	1.96			3.30	11.04
Commissioning	2	0.80	3.52	1.16	0.30	1.96			3.30	11.04
Commissioning spares	0.5	0.20	0.88	0.29	0.08	0.49			0.83	2.76
Temporary facilities	5	2.00	8.80	2.90	0.75	4.90			8.25	27.60
Vendor reps attendance										
Heavy lifts										
Freight, taxes &insurance	1	0.40	1.76	0.58	0.15	0.98			1.65	5.52
INDIRECT FIELD COSTS		**4**	**18**	**6**	**2**	**10**			**17**	**58**
ENGINEERING COSTS	**12**	**5**	**21**	**7**	**2**	**12**			**20**	66
TOTAL INSTALLED COST		**49**	**216**	**71**	**18**	**120**			**202**	**676**
CONTINGENCY	**10**	**5**	**22**	**7**	**2**	**12**			**20**	**68**
License fees										
Owners costs	7	3.43	15.09	4.97	1.29	8.40			14.15	47.33
OVERALL PROJECT COST		**57**	**252**	**83**	**21**	**140**			**236**	**791**

TABLE K 4

All costs in Millions of dollars **CASE 10 2020 USCPF With Carbon dioxide capture**

DESCRIPTION		**100 Coal/Ash Handling**	**200 Boiler Island**	**300 FGD**	**400 DeNox**	**500 steam turbines**	**600 CO2 capture**	**700 CO2 Comp Drying**	**800 BOP**	**TOTAL**
% of 2004 cost		**80%**	**80%**	**80%**	**100%**	**80%**	**66%**	**50%**	**100%**	
Direct Materials		30.00	113.00		13.00	70.00	21.00	11.00	136.00	
Construction		13.00	78.00	**see below**	3.00	28.00	35.30	9.00	43.00	
DIRECT FIELD COST (DFC)		**43**	**191**	**63**	**15**	**98**	**56**	**20**	**179**	**665**
	%DFC									
Construction management	2	0.86	3.82	1.26	0.30	1.96	1.12	0.40	3.58	13.30
Commissioning	2	0.86	3.82	1.26	0.30	1.96	1.12	0.40	3.58	13.30
Commissioning spares	0.5	0.22	0.96	0.32	0.08	0.49	0.28	0.10	0.90	3.33
Temporary facilities	5	2.15	9.55	3.15	0.75	4.90	2.80	1.00	8.95	33.25
Vendor reps attendance										
Heavy lifts										
Freight, taxes &insurance	1	0.43	1.91	0.63	0.15	0.98	0.56	0.20	1.79	6.65
INDIRECT FIELD COSTS		**5**	**20**	**7**	**2**	**10**	**6**	**2**	**19**	**70**
ENGINEERING COSTS	**12**	**5**	**23**	**8**	**2**	**12**	**7**	**2**	**21**	80
TOTAL INSTALLED COST		**53**	**234**	**77**	**18**	**120**	**69**	**25**	**219**	**815**
CONTINGENCY	**10**	**5**	**23**	**8**	**2**	**12**	**7**	**2**	**22**	**81**
License fees										
Owners costs	7	3.69	16.38	5.40	1.29	8.40	4.80	1.72	15.35	57.02
OVERALL PROJECT COST		**62**	**274**	**90**	**21**	**140**	**80**	**29**	**257**	**953**

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SECTION L

ECONOMIC ANALYSIS OF 2020 POWER PLANTS

1.0 Introduction

This section presents the economic evaluation of the additional 2020 power plant Cases 7-10 (described in Section J).

These cases are adaptations of Cases 1-4 (the 2004 power plants). The operating costs and capital costs of these 2004 cases have been modified by the expected improvement factors described in Section J to derive a new set of cases corresponding to what is expected in 2020. The evaluation of the 2020 cases follows the same methodology as that used for Cases 1-4 and is described below.

2.0 Basis of Comparison

The economic evaluation of the 2020 power plants is based on capital costs as shown in Section K above.

The expected performance of the plants is shown on Table L1

The gross power output of the plants is derived by applying the expected 2020 efficiency to the fuel firing rate: thus the comparison is based on Cases 1-4 fuel firing rates with the Case 7 rate corresponding to Case1, Case 8 corresponding to Case 2, Case 9 corresponding to Case 3 and finally Case 10 corresponding to Case 4.

The gross output is then corrected to account for extract steam requirements of the 2020 amine based carbon dioxide capture plant. As with Cases 2 and 4, this steam extraction results in a reduction in power output since less steam is expanded through the LP turbines, except that in the 2020 Cases 8 and 10 the loss is only 70% of that incurred in Cases 2 and 4 since there is an assumed reduction of 30% stripping steam requirement in the 2020 plants.

Because of this the gross efficiencies of Cases 8 and 10 is reduced from that of Cases 7 and 9 which do not have carbon dioxide capture plants fitted.

Further adjustments to the parasitic losses of the capture plant are made in accordance with the expected improvements described in Section J.

The variable operating cost data for the 2020 cases is assumed to be the same as for the corresponding 2004 cases and is shown on Table L2.

Tables L1 and L2 together with the capital cost data in Section K define the inputs for the economic model.

TABLE L1 CASE SUMMARY PROJECTED 2020 POWER PLANTS

	CASE 7	CASE 8	CASE 9	CASE 10
	NGCC	**NGCC+Capture**	**USCPF**	**USCPF+Capture**
Fuel Fired	**1396**	**1396**	**1723**	**1913**
Gross Output	**880**	**840**	**912**	**921**
Gross Efficiency	**63.0%**	**60%**	**53%**	**48%**
Losses				
FW Pumps	16	15	34	37
Draught Plant			8	9
Coal mills etc			5	5
ESP			2	2
Misc			8	9
Sub Total power plant	**16**	**15**	**57**	**62**
DCC Blower		10		7
Amine pumps		2		2
CO2 compression		30		60
Utility systems	8	10	10	15
FGD			5	5
DENOX			0.3	0.4
Sub Total Capture	**8**	**52**	**15**	**89**
Total Losses	**24**	**67**	**72**	**151**
Net Output	856	773	840	770
EFFICIENCY (Net power out/fuel in)	**61.32%**	**55.37%**	**48.73%**	**40.23%**
DELTA		6%		9%

NOTE: All Power generation figures in above table are MW

TABLE L2

CHEMICALS AND CONSUMABLE SUMMARIES
PROJECTED 2020 POWER PLANTS

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Case 7 NGCC WITHOUT CARBON DIOXIDE CAPTURE

Case 8 NGCC WITH CARBON DIOXIDE CAPTURE

Case 9 USC PULVERISED COAL WITHOUT CARBON DIOXIDE CAPTURE

Case 10 USC PULVERISED COAL WITH CARBON DIOXIDE CAPTURE

CHEMICALS AND CONSUMABLES SUMMARY

CASE 7: NGCC WITHOUT CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	880	
Net Power output	MW	856	
CO2 emission	Tonnes/Hr	294.07	343 g/kWh
CO2 Recovered	Tonnes/Hr	Nil	
Fuel Feedrate			
Coal		Nil	
Natural gas	Tonnes/Hr	107.19	
Chemicals and consumables			
Make-up water	Tonnes/Hr	4.28	Cost at 0.1US$/tonne
Limestone		Nil	
Ammonia		Nil	
MEA solvent		Nil	
Amine inhibitors		Nil	
Miscellaneous	$/MWh	0.05	
Catalyst for DENOX		Nil	
Waste Disposal			
Bottom ash		Nil	
Fly ash		Nil	
Gypsum		Nil	
Chloride		Nil	
Amine unit waste		Nil	
Waste water	Tonnes/Hr	4.28	Blow down from HRSG
Number of operators		62	

CHEMICALS AND CONSUMABLES SUMMARY

CASE 8: NGCC WITH CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	840	
Net Power output	MW	773	
CO2 emission	Tonnes/Hr	294.07	380g/KWh reduced to 57 g/kWh
CO2 Recovered	Tonnes/Hr	250.41	
Fuel Feedrate			
Coal		Nil	
Natural gas	Tonnes/Hr	107.19	
Chemicals and consumables			
Make-up water	Tonnes/Hr	135.37	
Limestone		Nil	
Ammonia		Nil	
MEA solvent	Kg/Tonne CO2	1.6	1300US$/Tonne
Amine inhibitors	US$/Tonne CO2	0.53	
Activated carbon	Kg/Tonne CO2	0.06	1000US$/Tonne
Soda Ash	Kg/Tonne CO2	0.13	110US$/Tonne
Miscellaneous	$/MWh	0.1	Allowance
Catalyst for DENOX		Nil	
Waste Disposal			
Bottom ash		Nil	
Fly ash		Nil	
Gypsum		Nil	
Chloride		Nil	
Amine unit waste	Tonnes/Ton CO2	0.0032	250US$/Tonne disposal cost
Waste water	Tonnes/Hr	135	
Number of operators		68	

CHEMICALS AND CONSUMABLES SUMMARY

CASE 9: USCPF WITHOUT CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	912	
Net Power output	MW	840	
CO2 emission	Tonnes/Hr	560.06	This is equivalent to 667 g/Kwh
CO2 Recovered		Nil	
Fuel Feedrate			
Coal	Tonnes/Hr	239.80	Coal priced at 46.6 Euros/tonne(55.92 $/tonne)
Natural gas		Nil	
Chemicals and consumables			
Make-up water	Tonnes/Hr	46.00	Cost at 0.1 $/tonne
Limestone	Tonnes/Hr	6.39	15US$/Tonne
Ammonia	Tonnes/Hr	0.42	336US$/Tonne
MEA solvent		Nil	
Amine inhibitors		Nil	
Miscellaneous	$/MWh	0.05	Allowance
Catalyst for DENOX	MM$	3.98	Based on a price of $300/ft3 of catalyst
Waste Disposal			
Bottom ash	Tonnes/Hr	7.31	
Fly ash	Tonnes/Hr	21.94	
Mill rejects	Tonnes/Hr	0.50	
Gypsum	Tonnes/Hr	11.58	From FGD plant at 9.5% water content
Chloride	Tonnes/Hr	0.60	Chloride purge from FGD plant
Amine unit waste		Nil	
Waste water	Tonnes/Hr	0.61	
Number of operators	Number	124	

CHEMICALS AND CONSUMABLES SUMMARY

CASE 10: USCPF WITH CO2 CAPTURE

ITEM	Units	Quantity	Notes
Gross power output	MW	921	
Net Power output	MW	770	
CO2 emission	Tonnes/Hr	95.06	This is equivalent to 123 g/kWh reducing to 105 g/kWh
CO2 Recovered	Tonnes/Hr	546.8	85% recovery
Fuel Feedrate			
Coal	Tonnes/Hr	266.256	Coal priced at 46.6 Euros/tonne (55.92$/Tonn
Natural gas		Nil	
Chemicals and consumables			
Make-up water	Tonnes/Hr	237.5	Boiler plant/FGD/EFG+@0.1 US$/Tonne
Limestone	Tonnes/Hr	7.73	15US$/Tonne
Ammonia	Tonnes/Hr	0.465	336US$/Tonne
MEA solvent	Kg/Tonne CO2	1.6	1300US$/Tonne
Amine inhibitors	US$/Tonne CO2	0.53	
Activated carbon	Kg/Tonne CO2	0.06	1000US$/tonne
Soda ash	Kg/Tonne CO2	0.13	110$/Tonne
Miscellaneous	$/MWh	0.1	Allowance for power plant plus EFG+
Catalyst for DENOX	MM$	4.326	
Waste Disposal			
Bottom ash	Tonnes/Hr	8.121	
Fly ash	Tonnes/Hr	24.36	
Mill Rejects	Tonnes/Hr	0.5	
Gypsum	Tonnes/Hr	14.055	
Chloride	Tonnes/Hr	0.61	
Amine unit waste	Tonnes/TonCO2	0.0032	250US$/Tonne for disposal
Waste water	Tonnes/Hr	115	
Number of operators	Number	130	

3.0 Results of Simulations

Calculations of the cost of electricity production have been made using the same models as was used for the analysis of Cases 1-4 and with the same base case economic parameters so that direct comparisons can be made. It should be emphasised that all of the economics calculations are based on current money values.

The results (presented in US c/kWh) are summarised in Table L3 below:-

TABLE L3:-Summary of Cost Of Electricity from 2020 plants

	NGCC	NGCC+CO_2Capture	USCPF	USCPF+CO_2 Capture
COE 2004	**3.13**	**4.4**	**4.39**	**6.24**
COE(2020)	**2.68**	**3.47**	**3.54**	**4.7**
Delta	**0.45**	**0.93**	**1.54**	**1.54**
Reduction (%)	**14**	**21**	**19**	**25**

This data shows that substantial reductions in the cost of electricity will result if the expected developments in the power plant and amine scrubbing technologies materialise by 2020.

It is interesting to note that for both natural gas and coal fired plants, the cost of electricity **with** carbon dioxide capture in 2020 is of the same order as costs of current technology **without** carbon dioxide capture i.e. the expected improvements in technology will almost offset the expected cost of capture of carbon dioxide.

4.0 Economic Analysis Output Sheets

Sheets for analysis of Cases 7-10 are given below:-

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

RUN NUMBER case 7

		TYPE	VALUE	UNITS
Calculated electricity cost		**output**	**26.86**	**$/MWH**
Discount rate		input	10	%
Load Factor years 2-25		input	85	%
Fuel Price		input	3	$/GJ
By-product price		input	0	$/Tonne
Solid Waste Disposal Cost		input	0	$/Tonne
Liquid waste Disposal Cost		input	0	$/tonne
Amine unit Waste Disposal Cost		input	0	$/Tonne
Chemical and consumable cost		input	0.00005	$/kWh
Insurance and local taxes		input	2	% Capex
Startup time		input	3	months
Load factor in start up year		input	60	%
Capital expenditure phasing		input		
		input		
	Year 1	input	40	%
	Year 2	input	40	%
	Year 3	input	20	%
		input		
Reference Plant CO2 emissions		input	0	g/kWh
Reference Plant Electricity cost		input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR [note1] **RUN NUMBER case 7**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	880
Fuel feedrate	input	MW	1396
Net power output	input	MW	856
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	343
TIC	input	MM$	281
Contingencies	input	MM$	28
Owners Cost	input	MM$	20
TOTAL CAPEX			329
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	131.92	MM$/YR
MAINTENANCE	output	7.73	MM$/YR
CHEMICALS + CONSUMABLES	output	0.39	MM$/YR
INSURANCE AND TAXES	output	6.18	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER case 7**

YEAR		-2	-1	Ist op year	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
Load Factor				21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor		40.00%	40.00%	20.00%																									
REVENUES																													
Electricity produced (GWH)				1593.444	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	6373.776	
Electricity sales revenue				42.79	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	171.18	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**42.79**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	**171.18**	
OPERATING COSTS																													
Fuel				28.03	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	
Maintenance				1.64	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	7.73	
Labour				4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables				0.08	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	6.18	
TOTAL OPERATING COST				**39.97**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	**130.40**	
FIXED CAPITAL EXPENDITURE		-131.6	-131.6	-65.8																									
WORKING CAPITAL				-0.5																									0.5
TOTAL YEARLY CASH FLOW				**-62.47**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**40.78**	**0.5**
Discount factor to get 2004 values		**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE	-£0.00	-131.6	-119.6364	-51.6299	30.64064	27.85512	25.32284	23.02076	20.92797	19.02542	17.29584	15.72349	14.29408	12.99462	11.81329	10.73936	9.763051	8.875501	8.068637	7.335125	6.668295	6.062086	5.510988	5.009989	4.554535	4.140487	3.764079	3.42189	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

Note: NPV here means sum of 2004 value of future positive yearly cash flows (Starting in 2007) less the total capex taken at 2004 values.

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

		TYPE	VALUE	UNITS
RUN NUMBER Case 8				
Calculated electricity cost		**output**	**34.69**	**$/MWH**
Calculated emission avoidance cost		**output**	**27.23373**	**$/Tonne CO2**
Discount rate		input	10	%
Load Factor years 2-25		input	85	%
Fuel Price		input	3	$/GJ
By-product price		input	0	$/Tonne
Solid Waste Disposal Cost		input	0	$/Tonne
Liquid waste Disposal Cost		input	0	$/tonne
Amine unit Waste Disposal Cost		input	0	$/Tonne
Chemical and consumable cost		input	0.00100	$/kWh
Insurance and local taxes		input	2	% Capex
Startup time		input	3	months
Load factor in start up year		input	60	%
Capital expenditure phasing		input		
		input		
	Year 1	input	40	%
	Year 2	input	40	%
	Year 3	input	20	%
		input		
Reference Plant CO2 emissions		input	343	g/KWH
Reference Plant Electricity cost		input	2.69	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER Case 8**

ITEM	Type	UNITS	VALUE
Number of operators	input		62
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	840
Fuel feedrate	input	MW	1396
Net power output	input	MW	773
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions	input	g/kWh	57
TIC	input	MM$	398
Contingencies	input	MM$	40
Owners Cost	input	MM$	27
TOTAL CAPEX			465
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	0
Maintenance charges	input	%	2.5

Calculated Operating costs at 100% output

FUEL	output	131.92	MM$/YR
MAINTENANCE	output	10.95	MM$/YR
CHEMICALS + CONSUMABLES	output	7.36	MM$/YR
INSURANCE AND TAXES	output	8.76	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	3.10	MM$/YR
LABOUR OHD + SUPERVISION	output	0.93	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER Case 8**

YEAR	-2	-1	Ist op year	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
Load Factor			21.25%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours			1861.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	40.00%	40.00%	20.00%																									
REVENUES																												
Electricity produced (GWH)			1438.94	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	5755.758	
Electricity sales revenue			49.92	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	199.66	
By-product sales revenue			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE			**49.92**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	**199.66**	
OPERATING COSTS																												
Fuel			28.03	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	112.13	
Maintenance			2.33	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	10.95	
Labour			4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	
Chemicals & Consumables			1.56	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	
Waste Disposal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes			8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	8.76	
TOTAL OPERATING COST			**44.71**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	**142.13**	
FIXED CAPITAL EXPENDITURE	-186	-186	-93																									
WORKING CAPITAL			-0.5																									0.5
TOTAL YEARLY CASH FLOW	**-186**	**-186**	**-87.30**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**57.53**	**0.5**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**
NET PRESENT VALUE **£0.00**	-186	-169.0909	-72.1478	43.22484	39.29531	35.72301	32.47546	29.52315	26.83923	24.3993	22.18118	20.16471	18.33155	16.66505	15.15004	13.77277	12.5207	11.38245	10.34768	9.406985	8.551804	7.774368	7.067607	6.425097	5.840997	5.309998	4.827271	0.038139

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

Note: NPV here means sum of 2004 value of future positive yearly cash flows (Starting in 2007) less the total capex taken at 2004 values.

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

ECONOMIC PARAMETERS

		TYPE	VALUE	UNITS
	RUN NUMBER case 9			
Calculated electricity cost		**output**	**35.39**	**$/MWH**
				/Tonne CO2
Discount rate		input	10	%
Load Factor years 2-25		input	85	%
Fuel Price		input	1.5	$/GJ
By-product price		input	0	$/Tonne
Solid Waste Disposal Cost		input	0	$/Tonne
Liquid waste Disposal Cost		input	0	$/tonne
Amine unit Waste Disposal Cost		input	0	$/Tonne
Chemical and consumable cost		input	0.000887	$/kWh
Insurance and local taxes		input	2	% Capex
Startup time		input	3	months
		input		%
Capital expenditure phasing		input		
		input		
	Year 1	input	20	%
	Year 2	input	45	%
	Year 3	input	35	%
		input		
Reference Plant CO2 emissions		input	0	g/kWh
Reference Plant Electricity cost		input	0	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER case 9**

ITEM	Type	UNITS	VALUE
Number of operators	input		124
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	912
Fuel feedrate	input	MW	1723
Net power output	input	MW	840
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions	input	g/kwh	667
TIC	input	MM$	676
Contingencies	input	MM$	68
Owners Cost	input	MM$	47
TOTAL CAPEX			791
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.6

Calculated Operating costs at 100% output

FUEL	output	81.41	MM$/YR
MAINTENANCE	output	26.78	MM$/YR
CHEMICALS + CONSUMABLES	output	7.09	MM$/YR
INSURANCE AND TAXES	output	14.88	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.20	MM$/YR
LABOUR OHD + SUPERVISION	output	1.86	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER case 9**

YEAR	2004 -2	2005 -1	2006 0	2007 1	2008 2	2009 3	2010 4	2011 5	2012 6	2013 7	2014 8	2015 9	2016 10	2017 11	2018 12	2019 13	2020 14	2021 15	2022 16	2023 17	2024 18	2025 19	2026 20	2027 21	2028 22	2029 23	2030 24	2031 25	2032 26
Load Factor				63.75%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours				5584.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor	20.00%	45.00%	35.00%																										
REVENUES																													
Electricity produced (GWH)				4690.98	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	6254.64	
Electricity sales revenue				166.02	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	221.36	
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE				**166.02**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	**221.36**	
OPERATING COSTS																													
Fuel				51.90	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	69.20	
Maintenance				17.07	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	26.78	
Labour				8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	8.06	
Chemicals & Consumables				4.52	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	6.02	
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes				14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	
TOTAL OPERATING COST				**96.43**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	**124.95**	
FIXED CAPITAL EXPENDITURE	-158.2	-355.95	-276.85																										
WORKING CAPITAL				-9.1																									9.1
TOTAL YEARLY CASH FLOW				**78.69**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**96.42**	**9.1**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	**-£0.00**	-323.5909091	-228.8017	59.12085	65.85311	59.86646	54.42406	49.47642	44.97856	40.8896	37.17236	33.79306	30.72096	27.92815	25.38923	23.08111	20.98283	19.0753	17.34118	15.76471	14.33156	13.02869	11.84426	10.76751	9.788645	8.898769	8.08979	7.354354	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

Note: NPV here means sum of 2004 value of future positive yearly cash flows (Starting in 2007) less the total capex taken at 2004 values.

ECONOMIC PARAMETERS

			TYPE	VALUE	UNITS
RUN NUMBER 10					
Calculated electricity cost			**output**	**47.04**	**$/MWH**
Calculated emission avoidance cost			**output**	**20.71**	**/Tonne CO2**
Discount rate			input	10	%
Load Factor years 2-25			input	85	%
Fuel Price			input	1.5	$/GJ
By-product price			input	0	$/Tonne
Solid Waste Disposal Cost			input	0	$/Tonne
Liquid waste Disposal Cost			input	0	$/tonne
Amine unit Waste Disposal Cost			input	0	$/Tonne
Chemical and consumable cost			input	0.002829	$/kWh
Insurance and local taxes			input	2	% Capex
Startup time			input	3	months
			input		%
Capital expenditure phasing			input		
			input		
		Year 1	input	20	%
		Year 2	input	45	%
		Year 3	input	35	%
			input		
Reference Plant CO2 emissions	**note 1**		input	667	g/kWh
Reference Plant Electricity cost	**note 1**		input	3.54	C/kWh

ECONOMIC ANALYSIS AND PRODUCTION COST CALCULATION

OPERATING COST ESTIMATE @100% OUTPUT FOR FULL YEAR[note1] **RUN NUMBER 10**

ITEM	Type	UNITS	VALUE
Number of operators	input		130
Cost of an operator	input	K$/YR	50
Labour overhead	input	%	30
	input		
Gross Power Output	input	MW	921
Fuel feedrate	input	MW	1913
Net power output	input	MW	770
By product output	input	Tonnes/HR	0
Solid waste output	input	Tonnes/kWh	0
Liquid wastes output	input	Tonnes/kWh	0
Amine unit liquid waste	input	Tonnes/tonne CO2	0
CO2 emissions Note 1	input	g/kWh	105
TIC	input	MM$	815
Contingencies	input	MM$	81
Owners Cost	input	MM$	57
TOTAL CAPEX			953
Chemicals inventory	input	MM$	0.5
Fuel Storage	input	MM$	8.6
Maintenance charges	input	%	3.43

Calculated Operating costs at 100% output

FUEL	output	90.39	MM$/YR
MAINTENANCE	output	30.73	MM$/YR
CHEMICALS + CONSUMABLES	output	22.82	MM$/YR
INSURANCE AND TAXES	output	17.92	MM$/YR
WASTE DISPOSAL	output	0.00	MM$/YR
OPERATING LABOUR	output	6.50	MM$/YR
LABOUR OHD + SUPERVISION	output	1.95	MM$/YR

Note 1 : A full year is 8760 Hours. This is scaled by load factor in the cash flow analysis

CASH FLOW ANALYSIS (Million $) **RUN NUMBER 10**

YEAR	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	-2	-1	0	1	2	3	4	5	6	7	8	9	10	11	12
Load Factor				63.75%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Equivalent yearly hours				5584.5	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expenditure factor	20.00%	45.00%	35.00%												
REVENUES															
Electricity produced (GWH)				4300.065	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42
Electricity sales revenue				202.27	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69
By-product sales revenue				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE				**202.27**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**
OPERATING COSTS															
Fuel				57.62	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83
Maintenance				19.59	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73
Labour				8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45
Chemicals & Consumables				14.55	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40
Waste Disposal				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Insurance and local taxes				17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92
TOTAL OPERATING COST				**118.14**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**
FIXED CAPITAL EXPENDITURE	-190.6	-428.85	-333.55												
WORKING CAPITAL				-9.1											
TOTAL YEARLY CASH FLOW				**93.23**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**
Discount factor to get 2004 values	**1.00**	**0.91**	**0.83**	**0.75**	**0.68**	**0.62**	**0.56**	**0.51**	**0.47**	**0.42**	**0.39**	**0.35**	**0.32**	**0.29**	**0.26**
NET PRESENT VALUE	**-£0.00**	-389.8636364	-275.6612	70.04662	79.47281	72.24801	65.68001	59.7091	54.281	49.34636	44.86033	40.78212	37.07465	33.70423	30.64021

YEAR	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expenditure factor														
REVENUES														
Electricity produced (GWH)	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	5733.42	
Electricity sales revenue	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	269.69	
By-product sales revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
TOTAL REVENUE	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	**269.69**	
OPERATING COSTS														
Fuel	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	76.83	
Maintenance	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	30.73	
Labour	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	
Chemicals & Consumables	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	19.40	
Waste Disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Insurance and local taxes	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	17.92	
TOTAL OPERATING COST	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	**153.33**	
FIXED CAPITAL EXPENDITURE														
WORKING CAPITAL														9.1
TOTAL YEARLY CASH FLOW	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**116.36**	**9.1**
Discount factor to get 2004 values	**0.24**	**0.22**	**0.20**	**0.18**	**0.16**	**0.15**	**0.14**	**0.12**	**0.11**	**0.10**	**0.09**	**0.08**	**0.08**	**0.07**
NET PRESENT VALUE	27.85474	25.32249	23.02044	20.92768	19.02516	17.2956	15.72327	14.29388	12.99444	11.81313	10.73921	9.762915	8.875377	0.631024

Reduce NPV to zero by setting Parameters!e8 to appropriate SP which then equals production cost

Note: NPV here means sum of 2004 value of future positive yearly cash flows (Starting in 2007) less the total capex taken at 2004 values.

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SECTION M

ROADMAP FOR 2020 DEVELOPMENTS

1.0 Introduction

This section of the report presents an outline of a road map for the development of the technologies for the 2020 power plants and for amine based carbon dioxide capture.

A series of major activities are defined which need to be undertaken to guarantee the readiness of the technologies by 2020. These form the basic building blocks of a road map.

It is not possible to fully define this road map, especially in terms of necessary delivery dates since much of the pace of the developments will be driven by market forces and legislative processes which are not clearly discernible and which are very likely to change over a sixteen year development period (viz: from 2004 to 2020).

2.0 Development of Road Map Building Blocks

Based on the prognostications of Section J of this report a set of developmental building blocks has been defined as follows:

2.1 Power Plants

- ***Ongoing Development of NGCC technology***: This is an essentially commercial activity which will develop higher efficiency designs of NGCC plants and is very much a continuation of the current activity in equipment supply companies. These companies are large enough and have global resources to support and stimulate the necessary parallel developments in gas and steam turbine technology, supercritical HRSG design and materials development. There are strong existing commercial drivers for these developments since any efficiency improvement, especially if it can be achieved at a low capital cost increment, gives lower production costs for electricity and this translates into higher profitability for producers and increased equipment sales for equipment manufacturers.

- ***Development of supercritical once through HRSG designs***: This activity is proceeding in equipment supply companies who will be expected to provide new designs for supercritical NGCC plants. Demonstration plants already exist and again, there is strong commercial stimulus to this work.

- ***Material development programmes***: These are needed to underpin advances in supercritical boiler and HRSG plant design as better alloys are needed. Programmes are in place in support of this activity.

- ***Design optimization***: This will continue as overall plant development progresses. It will be undertaken by system integration companies (EPC contractor, turnkey power plant designers) with the aim of producing cheaper integrated designs which embody the new technologies. It is an essentially commercially driven activity dependent on the markets need for the new technology.

- ***Ongoing development of USCPF boiler plants***: This is proceeding in equipment supply companies in support of perceived market demand for clean PF technologies. Again there is a market pull for this activity.

- ***Ongoing development of FGD***: The market is already capable of providing ultra FGD which can reduce SO_2 to the very low levels (10ppmv) required by amine scrubbing. This development will continue as SO_2 emissions are reduced even further and is likely to continue even if CCS never becomes a commercial reality.

Because of the market pull which already exists for higher and higher efficiency, there is a very strong probability that unabated high efficiency power plants will be available by 2020. The market will see to it and there is probably very little need for government research support.

There are already many joint industry programmes with members acting out of strong self interest to develop better technologies which result in increased business for the equipment suppliers. For example, it is already clear that it is possible to build a clean USCPF plant in 2004 even though public perceptions are not yet aware of this (there is probably a case for action in public outreach to get this message home and to ensure that clean coal remains an option for power generation).

2.2 Carbon Dioxide Capture Technology

The situation for carbon dioxide capture is very different since there is as yet no commercial driver for the development of the technology from its current base. It is very unlikely that developments will proceed without encouragement from government via the introduction of legislative programmes and the resulting carbon trading arrangements which force a commercial value onto CCS. Based on this thinking and on the developments discussed in Section J of this report, a set of necessary activities has been defined as follows:-

- ***New amine developments:*** Both of the commercially active technology owners have active programmes in place aimed at improving the performance of existing amines and finding new ones with the aim of lowering energy requirements, reducing corrosion and increasing carbon dioxide amine loadings. The future of the technology development is not however conditional on successful outcomes form this, nor from the development activities going on in various pure research organizations. Without these developments, the 2020 technology will merely result in higher operating costs and a higher capture cost.

- ***Demonstration programmes*** Given a "cost of carbon" which gave a commercial incentive, it would be possible to build a large scale carbon dioxide capture plant which could be integrated into a NGCC plant, using 2004 technology. This is not so in the case of USCPF plants because of the trace impurities in the flue gas, the removal of which requires demonstration before a very large capture plant could be designed with an acceptable commercial and technical risk level. So for the 2020 USCPF plant with capture to become a reality a fairly large demonstration is required. The absence of this constitutes a barrier which has to be surmounted (either by government/private possibly joint industry funding or development of an acceptable market price for captured CO_2) if a mitigated 2020 USCPF plant is to be a commercial reality.

- ***Design optimization/capital cost reduction*** This will follow if the development of the technology continues. To achieve the low costs reported in Section L, concerted design development and plant integration studies are required.