CO_2 CAPTURE AT GAS FIRED POWER PLANTS

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Further comments on specific aspects of the draft report were also received from certain post combustion capture technology providers.

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Background to the Study

Gas-fired power generation currently accounts for around 20% of global electricity production capacity and in the past twenty years it has been a popular choice for new power generation capacity, particularly in many developed countries, due to its high efficiency, low installed costs and good reliability and flexibility. Interest in natural gas fired power generation has increased recently because of the increasing availability of natural gas from shale and greater concerns about nuclear power in some countries.

A switch from coal to gas can help to reduce emissions from power generation substantially but it is not a CO_2-free generation option. In the longer term it is likely that new gas fired power plants will be required to be built and operated with CO_2 capture and storage (CCS) technology to achieve deep reductions in emissions. Most of the work on CCS has so far concentrated on coal and relatively little information on the performance and costs of gas fired power plants with CCS has been published. IEAGHG has therefore commissioned Parsons Brinckerhoff to undertake this techno-economic study on CO_2 capture at natural gas fired power plants.

Scope of Work

The study assesses the performance and costs of the following natural gas fired combined cycle power plants:

- A reference plant without CO_2 capture
- A plant with post combustion capture using non-proprietary MEA solvent scrubbing
- A plant with post combustion scrubbing using an advanced proprietary amine solvent
- A plant with recycle of cooled flue gas to the gas turbine inlet and post combustion scrubbing using MEA solvent
- An integrated power plant with natural gas reforming and pre-combustion scrubbing
- A plant with reforming, pre-combustion scrubbing, underground buffer storage of hydrogen-rich gas and a separate combined cycle plant.

The proprietary solvent case is representative of solvents being developed by various suppliers. Information was provided to the study contractor by MHI and Siemens but this case does not represent a specific proprietary technology.

The pre-combustion capture cases use air blown partial oxidation, shift conversion and CO_2 capture using Selexol solvent. In one of the cases the reformer and combined cycle power plant are integrated on one site. In the other case the reformer/CO_2 capture plant and the power plant are at separate sites and an underground salt cavern is used to provide 6 weeks of buffer storage of the hydrogen/nitrogen fuel gas. Information on the costs of underground hydrogen storage was provided by the study contractor based on their experience of building such facilities in the USA.

The technical performance of each plant was evaluated using process simulation and thermal plant simulation software (AspenPlus®, GTPRO®, GTMASTER® and Thermoflex®). Equipment lists and plant layout drawings were developed and these were used together with the contractor's in-house cost data and information provided by technology and equipment vendors, to develop high-level estimates of capital and operating costs. This information was subsequently used as inputs to an economic model which was used to evaluate the comparative economic performance of each plant and sensitivities to significant economic parameters.

The study report provides information on the designs of each of the plants, their power output, efficiency, greenhouse gas intensity, capital costs, operating and maintenance costs, levelised costs of electricity and costs of CO_2 avoidance. Process flow diagrams, stream data, equipment lists and plant layout diagrams are also provided.

Technical and economic basis

The technical and economic basis for the study is described in detail in the main study report. The main base case assumptions are:

- Greenfield site, Netherlands coastal location
- 2 GE9FB gas turbines + 1 steam turbine
- 9°C ambient temperature
- Mechanical draught cooling towers
- Base load operation
- Natural gas price: €6/GJ LHV basis (equivalent to €6.64/GJ HHV basis)
- 2011 costs
- 8% discount rate (constant money values)
- 25 year operating life
- 4 year plant construction time
- €5/t CO_2 storage cost
- €10/t CO_2 emission cost

Sensitivities to various economic parameters were evaluated, as discussed later.

The net power outputs of the plants are around 800MW but it was not possible to keep the net outputs the same in all of the cases because gas turbines are manufactured in fixed sizes and the ancillary steam and power consumptions are different in each of the cases, in particular they are substantially higher in the plants with CO_2 capture.

Levelised costs of electricity generation were calculated assuming constant (in real terms) prices for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from a lower capacity factor in the first year of operation. Costs of CO_2 avoidance were calculated by comparing the CO_2 emissions per kWh and costs of electricity (excluding any CO_2 emissions costs) of gas fired power plants with and without CO_2 capture. The cost of CO_2 avoidance would be different if an alternative baseline plant was used, for example a coal fired plant without capture.

Results and Discussion

Plant performance

The performances of the plants at base load are summarised in Table 1.

Table 1 Plant performance

	Net power output	CO_2 captured	CO_2 emissions	Efficiency HHV	Efficiency LHV	Efficiency penalty for capture
	MW	kg/MWh	kg/MWh	%	%	% points (LHV)
No capture	910	0	348	53.2	58.9	
Post combustion MEA solvent	789	365	41	46.1	51.0	7.9
Post combustion proprietary solvent	804	359	40	47.0	52.0	6.9
Post combustion MEA, flue gas recycle	785	362	41	46.4	51.3	7.6
Pre combustion	850	395	89	38.2	42.3	16.6
Pre combustion with hydrogen storage	737	454	104	33.2	36.8	22.1

The efficiency penalty for conventional MEA post combustion capture comprises 4.8 percentage points for steam extraction for solvent regeneration, 1.3 percentage points for the capture plant auxiliary power consumption (mainly for the flue gas booster fan), and 1.7 percentage points for CO_2 compression. The proprietary solvent case has a lower efficiency penalty mainly due to a 19% lower steam consumption for solvent regeneration. The regeneration heat consumption of the proprietary solvent is 2700kJ/kg CO_2 captured.

The flue gas recycle case has a lower efficiency penalty than the conventional MEA case due to a 21% lower ancillary power consumption for the capture plant, which is mainly due to the lower flue gas fan power consumption, and a 6% lower steam consumption. These improvements are partly offset by a lower combined cycle plant efficiency due to the higher gas turbine compressor inlet temperature which results from the replacement of some of the air by warmer recycle flue gas. Flue gas recycle has been the subject of successful combustor tests by turbine manufacturers and it is being tested in a large commercial gas turbine. This study is based on 50% flue gas recycle to show the maximum potential for this technique but recycle may be restricted to lower levels depending on the design of the turbine combustors.

The pre-combustion capture cases have significantly higher overall energy consumptions than the post combustion capture cases. There is a wide range of design options for natural gas pre-combustion capture plants, including the type of oxidant (air or purified oxygen), the CO_2 capture solvent (chemical or physical solvent), the oxidant supply (from the gas turbine compressor or a separate compressor), and there are a wide range of heat integration options. The choice of design options depended on the contractor's judgement of the balance between efficiency, capital costs, percentage CO_2 capture, risk and operability. On balance it was decided to accept a lower percentage capture for the pre-combustion capture cases (about 81.5%

compared to 90% for the post combustion cases) but it would be possible to design a pre-combustion capture plant for a higher capture rate if necessary.

Gas fired power plants with CCS are expected to operate at less than base load in future electricity systems that include large amounts of other low-CO_2 power generation (coal fired plants with CCS, wind, solar, nuclear etc), because the marginal operating costs of gas fired plants with CCS will usually be higher than those of the other technologies due to higher fuel costs. Gas fired power plant with CCS will therefore need to be able to operate flexibly and at lower annual capacity factors. IEAGHG has recently published a report on the operating flexibility of power plants with CO_2 capture[1], so to avoid duplication another detailed assessment of flexibility has not been undertaken. However, this study does assess plant performance and efficiency at part load (40% gas turbine load, corresponding to about 50% overall net output). At this part load condition the thermal efficiencies of plants with and without post combustion capture were estimated to be 6-7 percentage points lower than at 100% load[2]. It should be noted that in many cases a gas fired power plant would not spend a substantial fraction of its time operating at low load even if it operates at a low annual average capacity factor. For example a plant with a low capacity factor may spend much of its time operating at either high load or shut down, rather than operating continuously at part load, to avoid incurring the part load efficiency penalty.

Base case costs

Capital costs of power plants with and without CO_2 capture are shown in Table 1. The costs are expressed as EPC (Engineering, Procurement and Construction) costs excludes owner's costs and interest during construction, although these extra costs are taken into account in the calculation of levelised costs of electricity (LCOE). The LCOEs are for base load operation and include costs of CO_2 transport and storage and CO_2 emission costs. The annual capacity factors are assumed to be 93% for the plant without capture, 90% for plants with post combustion capture and 85% for plants with pre-combustion capture, in line with the expected differences in plant availabilities. The cost of CO_2 emission avoidance is the carbon emission cost that would be required to give the same electricity cost for power plants with and without CCS.

Table 2 Capital and operating costs

	EPC Plant Cost		**Levelised cost of electricity**		**Cost of CO_2 avoidance**
	€/kW	% increase for capture	€/MWh	% increase for CCS	€/tonne
No capture	637		53.9		
Post combustion MEA solvent	1401	120	76.6	42	84
Post combustion proprietary solvent	1165	83	70.7	31	65
Post combustion MEA, flue gas recycle	1285	102	74.1	37	76
Pre combustion	1595	150	91.7	70	156
Pre combustion with hydrogen storage	2421	280	118.0	119	272

[1] Operating flexibility of power plants with CCS, IEAGHG report 2012/6, June 2012.

[2] The part load efficiency penalty may be different for gas turbines from other manufacturers.

The proprietary solvent and flue gas recycle cases both have significantly lower costs than the conventional MEA base case, mainly due to their higher thermal efficiencies, smaller equipment sizes and, in the case of the proprietary solvent, lower solvent costs. It would be possible to combine flue gas recycle and a proprietary solvent and this is expected to achieve an even higher efficiency and lower costs. This case was beyond the scope of this study but it could be considered as part of a future study.

The pre-combustion capture cases have significantly higher costs than the post combustion capture cases. Costs of the pre-combustion case with hydrogen/nitrogen fuel gas storage are shown at base load in Table 1 for consistency with the other cases but it is recognised that this configuration's main advantages will be for lower annual capacity factors, which are discussed later in the section on cost sensitivities. The reason for the higher capital cost of this plant compared to the pre-combustion capture plant without storage is the cost of the storage facilities, which is equivalent to €218/kW, and the extra costs associated with having separate reforming/capture and power plants.

Breakdowns of the levelised costs of electricity are shown in Figure 1. It can be seen that in all cases the main contribution to the electricity cost is the fuel cost. The fuel costs are higher in the plants with capture due to their lower thermal efficiencies but the main reason for the higher overall costs is the higher capital charges.

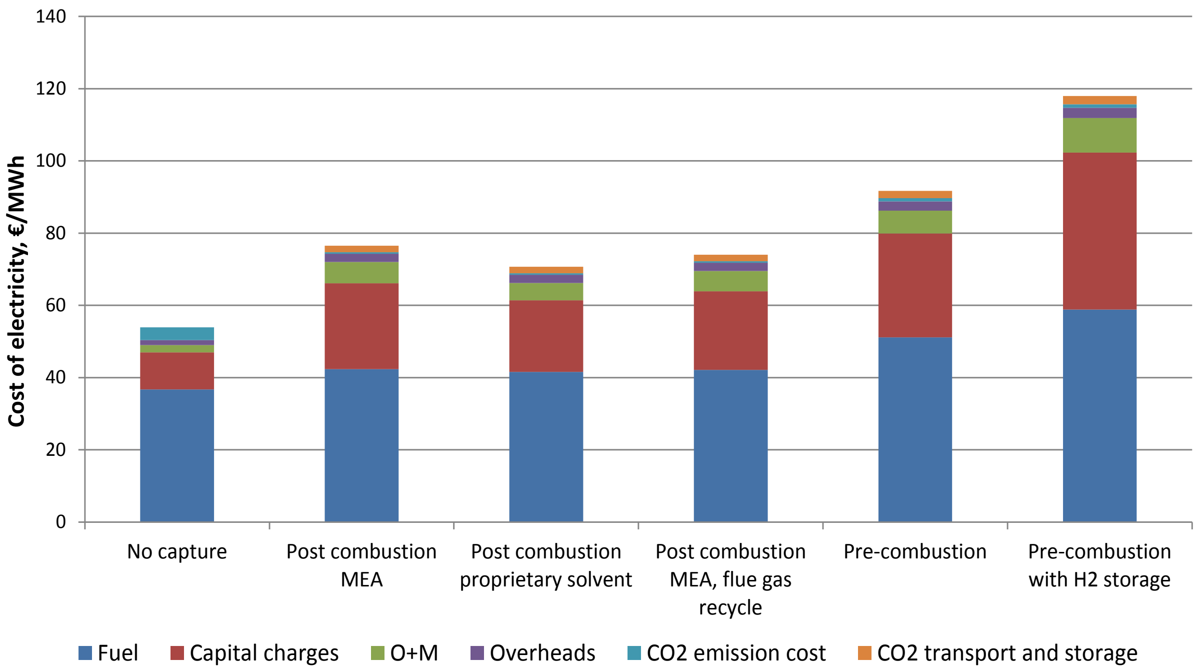

Figure 1 Levelised costs of electricity, base load operation

Cost sensitivities

Cost sensitivities were evaluated for all of the plants. Results for the plant with post combustion capture using a proprietary solvent are shown as an example in Figures 2 and 3, where costs of electricity and CO_2 abatement are shown for high, medium and low values of each parameter. Results for the other plants are given in the detailed study report.

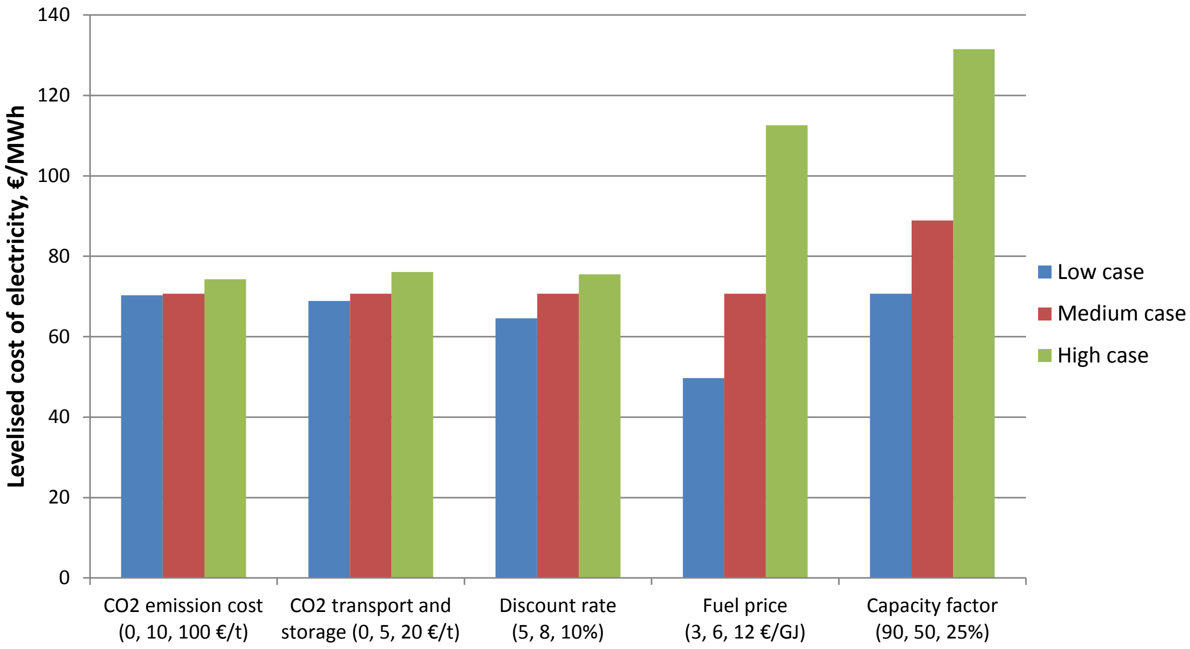

Figure 2 Electricity cost sensitivities (post combustion capture, proprietary solvent)

The electricity cost is most sensitive to the fuel price and the annual capacity factor. The wide range of fuel prices assessed in this study (3-12 €/GJ) represents the high degree of uncertainty regarding future gas prices and regional price differences.

The base case cost of CO_2 transport and storage was assumed to be €5/t of CO_2, which may represent a cost of on-shore storage close to the power plant. A zero (or even negative) net cost may apply if the CO_2 could be utilised for enhanced oil recovery (EOR). An increase to €20/t, representing offshore storage at a significant distance from the power plant, is shown to have a relatively small impact on the cost of electricity. Gas fired power plants have an advantage over coal fired plants in this regard because only about half as much CO_2 has to be stored per MWh.

Decreasing the capacity factor from 90% to 50% has a relatively modest impact on costs but a further reduction to 25% has a substantially greater effect. It should be noted that most of the alternative technologies for low-CO_2 electricity generation (renewables, nuclear etc.) have relatively high fixed costs, so their electricity costs will increase more steeply as the annual capacity factor is reduced. This should give gas fired plants with CCS a competitive advantage for intermediate load generation, which accounts for a significant fraction of overall electricity generation. For the purposes of the assessment of the sensitivity to annual capacity factor it is assumed that the plant is operated for part of the time at full load and for the rest of the time it is shut down, although in practice a plant may spend some time operating at part load. The costs do not include costs of start-up and shutdown and increased costs for part-load operation because evaluation of these costs was beyond the scope of this study and they would depend on the operating schedule of the plant.

The base case assumption for the CO_2 emission cost (€10/t) broadly represents current typical emission costs within the EU, although it is recognised that this is less than the cost that would be required to make CCS economically attractive. It can be seen that even an increase to €100/t would have only a small impact on the cost of electricity generation with CCS because it would only apply to the 10% of CO_2 that is not captured.

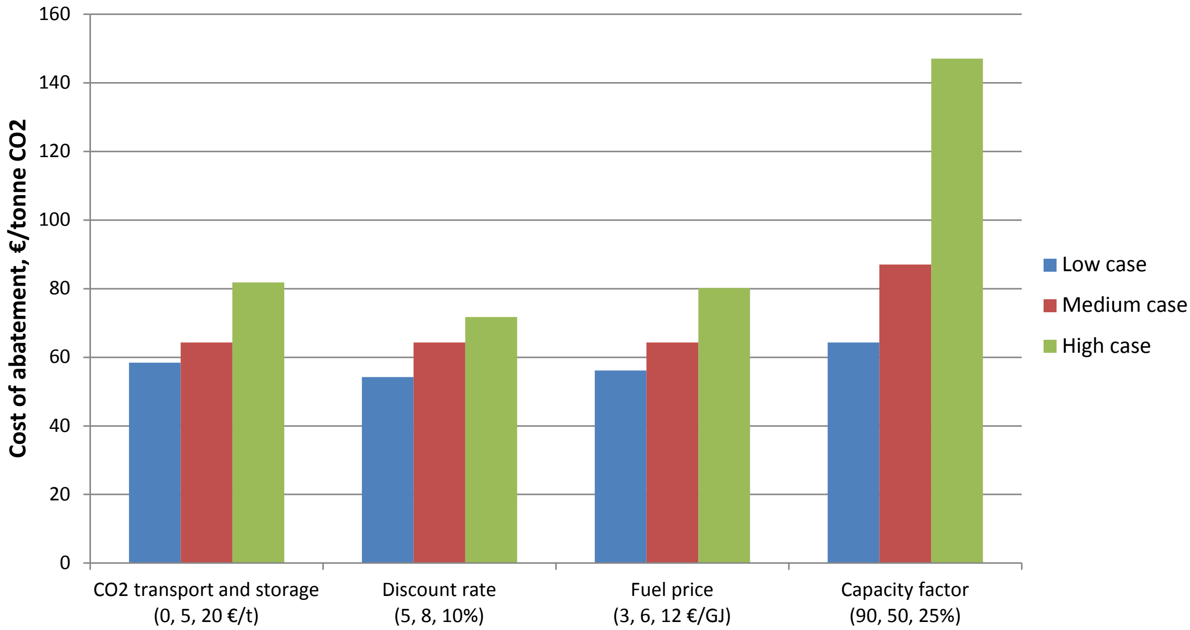

Figure 3 CO_2 abatement cost sensitivities (post combustion capture, proprietary solvent)

The CO_2 abatement costs shown in Figure 3 are mostly within a reasonably narrow range, between about 55 and 85 €/t CO_2, even for the wide range of sensitivity values considered in this study. This is because the parameter sensitivities (apart from the CO_2 transport and storage cost) affect the costs of the reference plant without capture as well as the plant with capture. Combinations of sensitivity values may of course result in abatement costs outside of this range. The only exception is the 25% capacity factor case, where the costs are substantially higher.

Because gas fired power plants are generally expected to operate at less than base load the sensitivity to capacity factor is particularly important, so costs of electricity for all of the cases at base load, 50% and 25% capacity factor are presented in Figure 4.

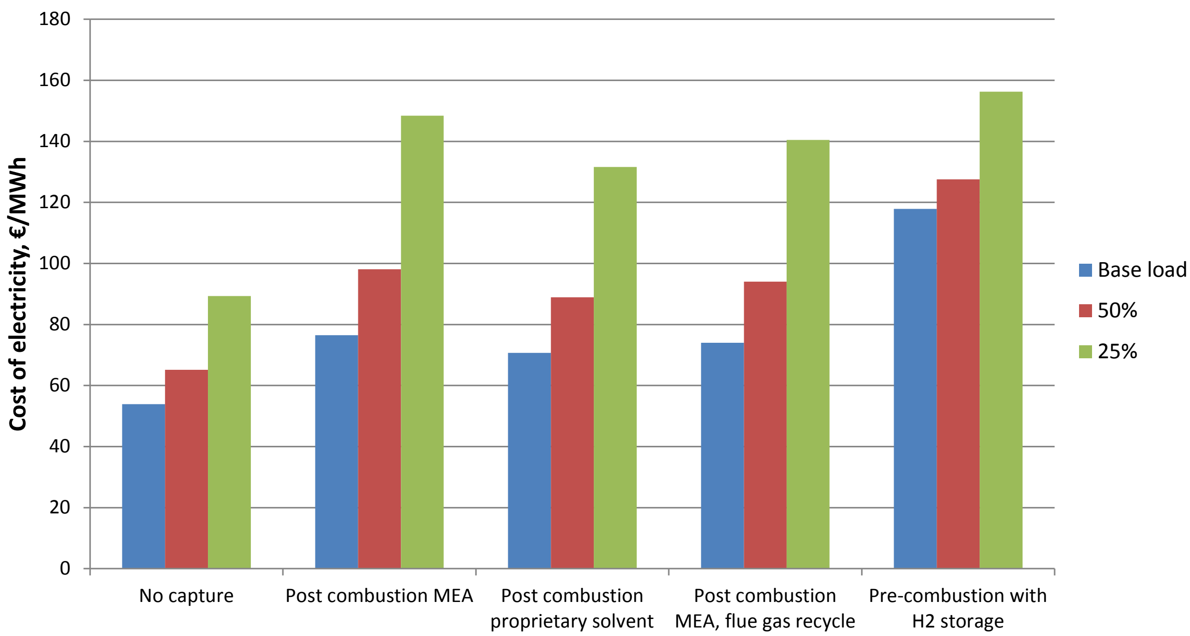

Figure 4 Sensitivity to annual capacity factor

At 25% capacity factor the costs of post combustion capture and pre-combustion capture with hydrogen storage are broadly similar[3]. Earlier work by IEAGHG[4] indicates that pre-combustion capture with hydrogen storage is a more attractive option for coal fired plants and the economic breakeven with post combustion capture occurs at a significantly higher annual capacity factor. It is therefore recommended that further work on the hydrogen storage option should be focussed on coal or biomass fired plants.

Plant layout and area requirements
Plot sizes for each of the plants are given in table 3 and typical layout diagrams are included in the main study report. The addition of post combustion capture increases the plant area requirement by about a third and pre-combustion capture approximately doubles the area requirement.

Table 3 Plant areas

	Plot size (m)	Area (ha)
No capture	360 x 250	9
Post combustion capture	490 x 250	12
Post combustion capture with flue gas recycle	480 x 250	12
Pre-combustion capture	440 x 390	17
Pre-combustion capture, separate sites: Reformer plant Power plant	360 x 350 360 x 250	21

Expert Review Comments

Comments on the draft report were received from reviewers in the power industry and research organisations who have worked on post and pre combustion capture at natural gas fired power plants. Comments on some aspects of the report were also received from post combustion capture technology vendors. Changes were made to take into account reviewers' comments. The contribution of the reviewers is gratefully acknowledged.

In general the reviewers thought the report was of a high standard and the results were broadly consistent with the results of other recent studies on CO_2 capture at gas fired power plants. Some reviewers emphasised the importance of operational flexibility of NGCC plants and asked for more information on this subject. This has partly been covered by a separate IEAGHG report on operational flexibility of power plants with CCS and further work on this subject could be carried out in future. To help to address the comments greater emphasis was given in the overview to operation at low capacity factors.

[3] The costs presented in this overview are based on the assumption that the pre-combustion capture case with hydrogen storage includes a single reforming and capture plant which operates continuously and which provides fuel gas to multiple combined cycle plants operating at lower annual capacity factors. In the main study report it is assumed that the reformer and capture plant would feed only one combined cycle plant and the reformer would also operate at 25% capacity factor.

[4] Flexible CCS plants, a Key to Near-zero Emission Electricity Systems, J. Davison, Energy Procedia 4 (2011) 2548-2555.

Conclusions

- Adding post combustion capture reduces the thermal efficiency of a natural gas combined cycle plant by about 7-8 percentage points, increases the capital cost per kW by about 80-120% and increases the cost of base load electricity generation by about 30-40%.
- The cost of CO_2 emission avoidance (i.e. the carbon emission cost required to give the same electricity cost from base load NGCC plants with and without CCS) is about €65/tonne in the lowest cost case evaluated in this study (post combustion capture with a proprietary solvent). The abatement cost compared to an alternative base line such as a coal fired plant may be lower.
- Recycling part of the cooled flue gas to the gas turbine compressor inlet would increase the CO_2 concentration in the feed to the CO_2 capture unit, which could increase the thermal efficiency by up to 0.3 percentage points and reduce the cost of electricity by up to 8 percent.
- Natural gas combined cycle plants with CCS may operate at annual capacity factors lower than base load, particularly in electricity systems that include large amounts of other low-CO_2 generation. In the lowest cost case, reducing the annual capacity factor to 50% would increase the cost of CO_2 avoidance to €87/tonne.
- The study indicates that, based on current technology, pre-combustion capture in natural gas fired combined cycle power plants is not economically competitive with post combustion capture.

Recommendations

- This study could be extended to assess a combination of a high efficiency proprietary post combustion capture solvent and gas turbine flue gas recycle.
- The performance and costs of natural gas fired power plants with other CO_2 capture technologies such as other liquid solvents, solid sorbents or membranes should be evaluated if sufficient input data become available.
- Further work should be undertaken to assess the operation of gas fired power plants with CCS in future electricity systems that include large amounts of other low-CO_2 generation technologies.
- IEAGHG should undertake a new study to assess the performance and costs of baseline coal fired power plants with CO_2 capture.

IEA Greenhouse Gas R&D Programme





MARCH 2012

CO_2 CAPTURE AT GAS FIRED POWER PLANTS

PARSONS BRINCKERHOFF

CO_2 CAPTURE AT GAS-FIRED POWER PLANTS STUDY REPORT

IEA GREENHOUSE GAS R&D PROGRAMME

MARCH 2011

FINAL REPORT

CO_2 Capture at Gas Fired Power Plants Study

Project Number 64225A

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CONTENTS

APPENDICES:

LIST OF ABBREVIATIONS

ATR	Auto-thermal Reforming
bara	bar (absolute)
barg	bar (gauge)
BTU	British thermal unit
^{o}C	degrees centigrade
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CCP	capture and compression plant
CCR	central control room
CCS	carbon capture and storage
CEM	Continuous emission monitoring
CPO	catalytic partial oxidation
CTS	Haldor Topsøe A/S proprietary burner design
CW	cooling water
CO_2	carbon dioxide
DCC	direct contact cooler
DCS	distributed control system
DECC	Department of Energy and Climate Change
DLN	dry low NO_x
EGR	Exhaust Gas Recirculation
EIA	Environmental Impact Assessment
EPC	engineer, procure, construct
EU	European Union
EUR	Euro
EUR¢	Euro cents
FEED	front-end engineering design
FGD	flue gas desulphurisation
GBP	Great British Pound
GE	General Electric
GHG	green house gas
GT	gas turbine
GTG	gas turbine generator
h	hours
HHV	higher heating value
HMB	heat and mass balances
HP	high pressure
HRSG	heat recovery steam generator
HT	high temperature
Hz	hertz
IEA	International Energy Agency
IED	Industrial Emissions Directive
IGCC	integrated gasification combined cycle
IP	intermediate pressure
ISO	International Standards Organization
KEPCO	Kansai Electric Power Company
kg	kilogram
kJ	kilojoule
km	kilometre
kPa	kilopascal
kV	kilovolt
kW	kilowatt
kWh	Kilowatt-hour
LCPD	Large Combustion Plant Directive

LHV	lower heating value
LP	low pressure
LSIP	large-scale integrated projects
LT	low temperature
LV	low voltage
m^3	cubic metres
MEA	Mono-ethanol amine
MCR	maximum continuous rating
MHI	Mitsubishi Heavy Industries
MJ	megajoule
MP	medium pressure
MSG	minimum stable generating
MV	medium voltage
MW	megawatt
MWe	megawatt (electric)
MWth	megawatt (thermal)
MWh	megawatt-hour
OEM	original equipment manufacturer
OH	operating hour
PB	Parsons Brinckerhoff
PCS	plant control system
PFD	process flow diagram
POX	partial oxidation
PM	particulate matter
ppm	parts per million
RAM	reliability, availability and maintainability
RMS	reducing and metering station
SEV	sequential combustion burner system
STG	steam turbine generator
t	tonne
TCR	total capital requirement
TEG	Tri-ethylene glycol
TPC	total plant cost
TWh	terawatt hour
UBC	Uniform Building Code
USA	United States of America
USD	United States Dollar
VOC	volatile organic compound
WPCR	Water Pollution Control Regulation
wt	weight

1. INTRODUCTION

1.1 Background

Gas-fired power generation currently accounts for around 20% of global electricity production capacity and in the past twenty years has proven to be the technology of choice for new power generation capacity, particularly in developed countries. It is *efficient*, with modern combined cycle gas turbine (CCGT) configurations able to achieve fuel efficiencies of between 50 and 60%. The technology is also relatively *cheap*, with an installed capital cost of around EUR450/kW to EUR700/kW[1]. It is also *reliable* and *flexible*, capable of responding quickly to demand-side variations or fuel price fluctuations, allowing operators to maximise operating revenues and capitalise on electricity-market price opportunities.

Gas-fired power generation is also important in the context of international efforts to avoid catastrophic climate change. Currently 60% of all greenhouse gas emissions are energy related, and it is recognised that without significant policy change energy-related emissions will increase by 57% to 2030[2]. In comparison to coal-fired power generation, gas has a much lower Greenhouse Intensity; a typical CCGT will emit around 370kgCO_2/MWh, in comparison to around 750 to 900kgCO_2/MWh for a black coal power station. In the recently published Electricity Market Reform White Paper[3] the UK Government emphasised the importance of new gas-plant in the near term, and through a carbon price floor and emissions performance standard would seek to substantially reduce CO_2 emissions from the UK electricity generation sector as aging coal plant retires. It is expected that much of this new generating capacity will take the form of new-build gas plant, to be constructed over the next 8 to 10 years.

However, while a switch to gas can help to reduce power sector emissions substantially, it is not a CO_2-free generation option, and in the longer term new gas plant will be required to be built and operated with carbon capture and storage (CCS) technology. The IEA Energy Technology Perspectives BLUE Map emissions target of 14Gt CO_2 emissions by 2050 (which represents a 50% reduction on 2005 emission levels), can only be met through widespread deployment of Gas + CCS in conjunction with renewables, new nuclear, Coal + CCS, and a range of energy efficiency and demand side measures.

Table 1 – Current and predicted contribution of gas power generation (TWh per year)[4]

Total annual production (TWh/yr)	2007	Baseline 2050	BLUE map 2050
Total	19756	46186	40137
Gas	4126	10622	4283
Gas + CCS	0	0	1815
Share of total (%) Gas	21	23	11
Share of total (%) Gas + CCS	0	0	5

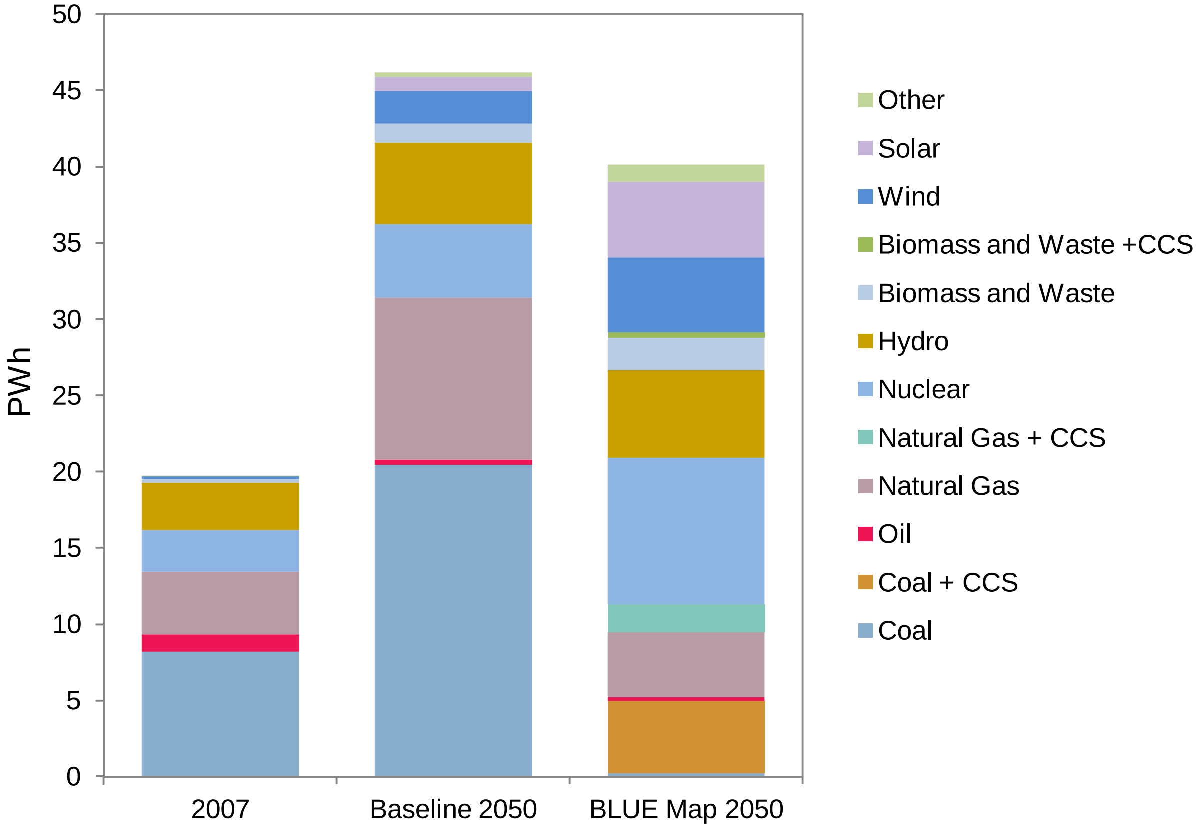


Figure 1 - BLUE map emissions reduction plan[5]

It may be further noted that since the BLUE Map emissions reduction plan was developed in 2008, global natural gas reserve estimates have been subject to a significant upturn revision, with the development of technological advances which enable extraction of natural gas from shale rock. US natural gas reserve estimates have recently increased from 30 to 100 years worth at current consumption rates, with energy analysts suggesting the US market is now oversupplied[6]. Further evidence of this is provided by the US DOE Energy Information Administration which updated its gas long term price forecasts in March 2011 showing a long term price of around USD4.5/GJ; this compares with the price forecasts made in 2007 for natural gas in 2011 of USD12/GJ.

Furthermore, in light of events at the Fukushima nuclear facility in Japan and the subsequent decision made by several governments not to replace aging nuclear assets, there is a strong indication that gas as a fuel will play an increased role in the future energy mix.

1.2 Purpose

Power generation CCS deployment efforts to date have been focussed on areas where they will have greatest impact i.e. on mitigating coal plant CO_2 emissions. Of the 77 large-scale integrated CCS projects (LSIP) which are currently in development, over 53% are associated with coal-fired power generation[7], by far the largest of any sector. However, given that gas-fired power generation has such a vital role to play in the future global energy mix, it is important that carbon capture technology is also demonstrated on gas-fired power plants to understand the impacts on the technical and commercial performance, as well as other issues such as the impact of the capture plant on plant operational flexibility and running costs.

The purpose of this study is to *investigate the technical and economic performance of CO_2 capture and compression technologies at new-build gas-fired power plants*. It builds on previous work undertaken by the IEA Greenhouse Gas R&D Programme (IEA GHG) in 2005, which studied the impacts of retrofitting CO_2 capture and compression technology to existing gas-fired power plants. This study is intended to provide an *up-to-date, independent benchmark* of CO_2 capture technologies developed specifically for new build gas-fired power plants, and provide a comparison of pre-combustion and post-combustion technologies. This is achieved through process plant and thermal plant performance simulation, concept design and sizing, cost estimation, and economic modelling for several scenarios to allow evaluation against key technical and economic metrics such as plant net output (MW_e), plant efficiency (%), Greenhouse Intensity (gCO_2/kWh), lifetime cost of electricity (EUR/kWh), and cost of CO_2 abatement (EUR/tCO_2).

1.3 Scope of the Study

The study considers five scenarios, selected to examine the implications of capture technology type, configuration and plant operation, on the metrics outlined above. These scenarios are:

1. A CCGT power plant (Reference Plant);
2. Scenario 2 not used
3. A CCGT power plant with post-combustion capture;
4. A CCGT power plant with post-combustion capture and flue-gas recirculation;
5. A Combined cycle power plant with Natural Gas reforming and pre-combustion capture; and
6. A Natural Gas Reforming plant with pre-combustion capture, providing hydrogen to a remote combined cycle power plant or intermediate storage.
7. Scenario 7 not used

For each scenario the technical performance is evaluated using process simulation and thermal plant simulation software, which are also used to prepare associated Heat and Mass balances (HMB), Process Flow Diagrams (PFD), equipment lists, plant layout drawings and utility consumption lists. This information is then used to develop high-level estimates for capital and operating costs, which are subsequently used as inputs to an economic model which is used to evaluate the comparative economic performance of each scenario.

This report compiles conclusions from the study, and presents the technical and economic results along with discussion and commentary on the key findings and recommendations.

1.4 Structure of the report

The report is structured as follows:

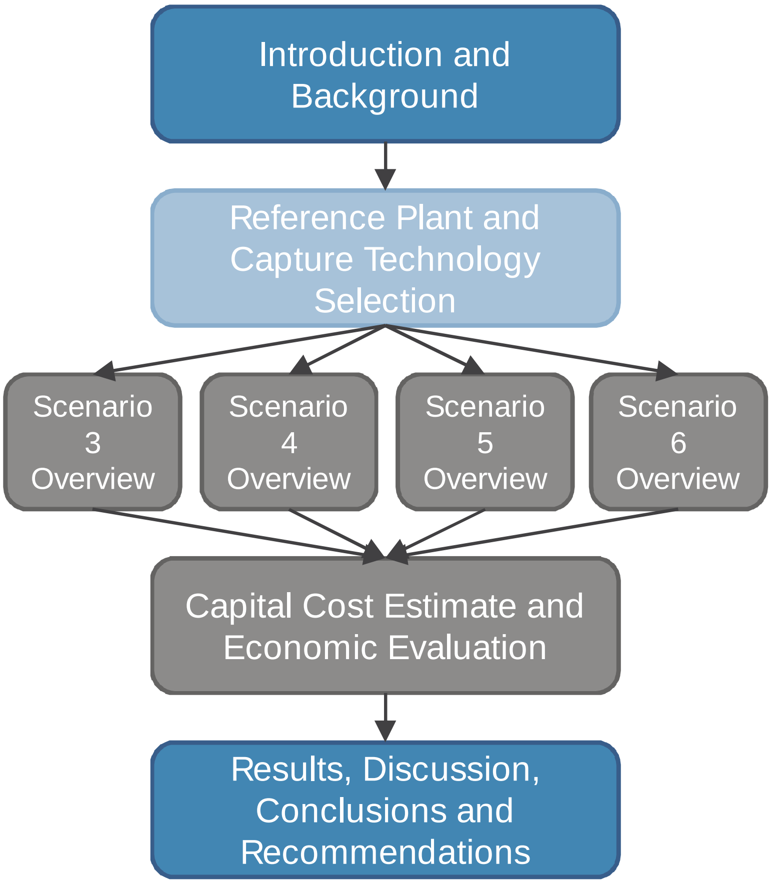


Figure 2 – Report Structure

1.5 Credit to Technology Providers and other support

This report was produced by Parsons Brinckerhoff which is an independent global consulting company with no affiliation to any one technology provider. Approaches were made to a wide range of technology providers in the CCS market to seek to ensure that the study outputs were reflective of the present state of technology development in this rapidly developing field. Parsons Brinckerhoff would like to acknowledge the contributions made by several equipment suppliers and technology providers in the undertaking of this work, in particular **Mitsubishi Heavy Industries Ltd.**, **Siemens plc**, and **Haldor Topsøe A/S**, for the provision of performance information and other advice in support of the study.

In addition, Parsons Brinckerhoff would also like to thank a number of other companies for the provision of supplementary information in support of the cost estimation exercise, including *Howden Group Ltd, General Electric Company, Sulzer Ltd, Boustead International Heaters, SPX Flow Technology*, and *Alfa Laval Ltd*.

1.6 Modelling Software Used and Methodology

For the purposes of plant modelling, Parsons Brinckerhoff used a combination of software platforms. These include GE Gate-cycle© and Thermoflow GT Pro© for modelling gas turbine and steam turbine performance, and AspenTech© software, for modelling natural gas reforming processes and pre and post combustion carbon capture processes.

1.6.1 Process Plant Performance Modelling

For the purposes of process modelling of CO_2 capture and CO_2 compression processes, Parsons Brinckerhoff utilised AspenPlus® (v7.2). AspenPlus® is a market-leading process modelling tool for conceptual design, optimization and performance monitoring in the chemical, oil and gas, metal and minerals as well as coal and power industries. AspenPlus® includes an extensive database of pure component and phase equilibrium data for conventional chemicals, electrolytes, solids, and polymers which lends to its ability to model various CO_2 separation technologies.

1.6.2 Thermal Plant Performance Modelling

For the purposes of thermal power plant modelling, the Thermoflow Inc. suite of software has been utilised. Primarily the GT PRO, GT MASTER and Thermoflex programmes (Version 21) from the Thermoflow Inc. suite have been used. GT PRO is a leading gas turbine and combined cycle plant modelling programme that utilises a database of gas turbines with mapped performance curves and allows the experienced user to accurately simulate overall plant performance at design conditions. GT MASTER utilises a design from GT PRO and enables the performance of off-design scenarios to be modelled, such as part-load operation and different ambient conditions. The Thermoflex programme allows a thermal plant model to be developed from individual components and thus permits a much higher degree of flexibility in the model development, allowing for bespoke design concepts to be evaluated. A GT PRO model can be imported into Thermoflex, in which it is converted into its separate components, speeding up the development of bespoke models. The plant design can then be altered within Thermoflex, adding or removing components and linking them as desired, and the performance evaluated. As with GT MASTER, Thermoflex has an off-design mode that enables the performance of off-design scenarios to be evaluated.

The methodology of thermal power plant modelling for the reference scenario and for the reforming scenarios was to utilise GT PRO for the design case and GT MASTER for the part-load case. The post-combustion carbon capture scenarios required a significant degree of two-way integration between the thermal power plant model and the carbon capture plant process model. The two-way integration generally involved the transfer of steam and condensate between the plants (and models) and interfaces with the flue gas flow. To aid the iterative process and ensure the thermal power plant model and the carbon capture plant process model provide an accurate overall plant performance model, Thermoflex was used to model the entire process (through the use of bespoke design concepts) and thus provided starting points for the interface parameters used in the carbon capture plant process model.

1.6.3 Economic Modelling

The economic model used is based upon Parsons Brinckerhoff's industry-leading Powering the Nation model; an analysis tool developed specifically by Parsons Brinckerhoff for the Powering the Nation Report which is available at http://www.pbworld.com/regional/uk_europe_specialty/. The model takes account of multiple factors for each generation type including predicted costs for fuel, carbon, operation and maintenance. It also includes factors reflecting optimum economic plant life, operating regime, and construction scheduling. Output data from the performance modelling exercise is used to assess the relative economic performance of each of the available solutions. The economic model is used to determine key parameters such as lifetime cost of electricity, costs of CO_2 avoidance, operation and maintenance costs, and others.

1.7 Design Basis and other definitions used in the report

The study is based on the IEA GHG's standard assessment criteria and basis for design, presented in '*Criteria for Technical and Economic assessment of plants with low CO_2 emissions*'. A high-level summary of assumptions are presented here for context.

1.7.1 Site and ambient conditions

The site is located in the north-east Netherlands, at a coastal location, and with the following atmospheric conditions;

Table 2 – Ambient Conditions

Ambient Conditions	
Temperature (dry-bulb average), ^oC	9
Maximum temperature, ^oC	30
Minimum temperature, ^oC	-10
Humidity (average), %	80
Pressure (average), kPa	101.3

1.7.2 Fuel Supply

The natural gas supply specification for all scenarios is as follows:

Table 3 – Natural Gas Supply Specification

Supply temperature	9	^{o}C
Supply pressure	7.0	MPa
Molecular Weight	18.02	
Total LHV + Sensible Heat @ 9 ^{o}C	46474	kJ/kg
Total Fuel Enthalpy reference to 0^{o}C	51631	kJ/kg
Volumetric LHV @ 25^{o}C (scm: m^3 @ 25^{o}C and 1.013bar)	34258	kJ/scm
Volumetric HHV @ 25^{o}C (scm: m^3 @ 25^{o}C and 1.013bar)	37920	kJ/scm
Heating Values		
LHV @ 25^{o}C	46506	kJ/kg
HHV @ 25^{o}C	51477	kJ/kg
Analysis of Fuel (vol. %)		
Hydrogen H_2	0	%
Oxygen O_2	0	%
Water Vapour H_2O	0	%
Nitrogen N_2	0.89	%
Carbon Monoxide CO	0	%
Carbon Dioxide CO_2	2	%
Methane CH_4	89	%
Ethane C_2H_6	7	%
Propane C_3H_8	1	%
n-Butane C_4H_{10}	0.1	%
n-Pentane C_5H_{12}	0.01	%
Hexane C_6H_{14}	0	%
Ethylene C_2H_4	0	%
Propylene C3H6	0	%
Butylene C_4H_8	0	%
Pentene C_5H_{10}	0	%
Benzene C_6H_6	0	%
Hydrogen Sulphide H_2S	0	%
Argon Ar	0	%
Total	100	%

1.7.3 CO_2 product specification

Captured carbon dioxide is compressed to around 110bar and cooled to around 30^{o}C, and dehydrated to the following specification at the battery limits of each scenario (note the values presented below represent maximum allowable concentrations);

Table 4 – CO_2 product specification

CO_2 maximum impurities		
H_2O	500	ppm
N_2 / Ar	4	%
O_2	100	ppm
CO	0.2	%
CH_4 and other hydrocarbons	4	%
H_2S	200	ppm
SO_2	100	ppm
NO_2	100	ppm
Total non-condensables	Up to 4	%

1.7.4 Reformed Natural Gas specification

For those scenarios which involve reforming of natural gas and pre-combustion capture, the specification for the reformed natural gas (following acid gas clean-up) is as follows:

Table 5 – Reformed Natural Gas Supply Specification

Supply temperature	100	^oC
Supply pressure	36.1	bar
Molecular Weight	14.74	
Total LHV + Sensible Heat @ 9^oC	9337	kJ/kg
Total Fuel Enthalpy reference to 0^oC	11030	kJ/kg
Volumetric LHV @ 25^oC (scm: m^3 @ 25^oC and 1.013bar)	5537	kJ/scm
Volumetric HHV @ 25^oC (scm: m^3 @ 25^oC and 1.013bar)	6510	kJ/scm
Heating Values		
LHV @ 25^oC	9188	kJ/kg
HHV @ 25^oC	10802	kJ/kg
Analysis of Fuel (vol. %)		
Hydrogen H_2	52.02	%
Oxygen O_2	0	%
Water Vapour H_2O	0.01	%
Nitrogen N_2	44.01	%
Carbon Monoxide CO	0.47	%
Carbon Dioxide CO_2	1.95	%
Methane CH_4	1.02	%
Ethane C_2H_6	0	%
Propane C_3H_8	0	%
n-Butane C_4H_{10}	0	%
n-Pentane C_5H_{12}	0	%
Hexane C_6H_{14}	0	%
Ethylene C_2H_4	0	%

Propylene C3H6	0	%
Butylene C_4H_8	0	%
Pentene C_5H_{10}	0	%
Benzene C_6H_6	0	%
Argon Ar	0.52	%
Total	100	%

1.7.5 Plant Capacity

The scenarios have been developed such that the net power output is approximately 800MWe at the site ambient conditions, although power output varies from scenario to scenario according to the parasitic load (both thermal and electrical) of the capture and compression plant. In all scenarios the CCGT configuration is 2 + 1 (i.e. two gas turbines exhausting to separate triple-pressure HRSG's, feeding steam to one steam turbine).

Electricity is generated at 50Hz and gross electrical output is considered to be the sum of electrical power output at each of the generator terminals (i.e. before accounting for auxiliary plant loads).

Plant efficiency is presented on an LHV basis.

1.7.6 Environmental Limits

Limits for emissions to air and water of sulphur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter (PM), are those which apply to new power plants in the Netherlands.

The requirements of the EU Industrial Emissions Directive (IED) (Directive 2010/75/EU) are such that CCGT power plants must adhere to stringent emissions standards, which cover emissions of NO_x.

Based on the requirements of the IED, CCGT power plant are required to limit their NO_x emissions to 50 mg/Nm^3 , and so this has been used as the NO_x limit for the study.

N.B This requirement applies to CCGT operation above 70% load, and measurements are calculated at a temperature of 273.15K, a pressure of 101.3kPa and after correction for the water vapour of the waste gases and at a standardised O_2 content of 15% for gas turbines and gas engines.

2. OVERVIEW OF SCENARIO 1 (THE REFERENCE PLANT)

For the purposes of providing a common basis for the study, a reference plant and common GT was modelled across all scenarios. The reference plant chosen is a CCGT power plant comprising primarily of two gas turbine generators (GTG), two heat recovery steam generators (HRSG) and one steam turbine generator (STG), otherwise termed a *2 + 1 configuration*.

All scenarios have been based on a 2 + 1 configuration, and have been developed as far as possible to achieve a net power output of approximately 800MWe at the specified site ambient conditions. To achieve this output with a 2+1 configuration requires gas turbines of the heavy-duty F-class type in the nominal 270-330 MW ISO rating range. For pre-combustion capture scenarios the GTs must also be capable of handling high-hydrogen (H_2) content fuel. These requirements formed the basis for the selection of an appropriate reference GT.

This section examines the heavy duty GT market as at mid-2011, to establish the major companies who manufacture machines which meet these requirements, and presents a justification for the selection of the reference GT which was chosen for the study.

2.1 Plant Description

As stated, the reference plant is a CCGT plant comprising two GTGs, two HRSGs and one STG. The multi-shaft arrangement has been selected because while the choice has little bearing on the cost estimation and performance, multi-shaft plants (due to their double-flow low pressure steam turbines) are generally considered to be preferable for post-combustion carbon capture. A three-pressure reheat steam system is employed, as is typical for plants in this class, and the key steam temperature and pressures are as follows:

- High Pressure (HP) steam to turbine: 600°C and 170bara; and
- Hot Reheat (MP or IP) steam to turbine: 600°C and 40bara.

It is recognised that these steam conditions are higher in both temperature and pressure than what is currently typical. The terms of reference (ToR) for the study require plant selection on the basis of technology which will be commercially available in 2020, at which point natural gas fired power plants (with or without CCS) are expected to be required in significant numbers to replace aging or retiring assets. Since most original equipment manufacturers (OEMs) are already considering/demonstrating similar steam conditions to those selected, it is considered that utilising these conditions in CCGT plants will be proven and typical by 2020.

2.2 Gas Turbine Selection

The main options for 50 Hz large GTs being marketed globally at the time of conducting the study are:

- Siemens SGT5-4000F (for simplicity, the practically equivalent Ansaldo AE94.3A was excluded);
- Siemens SGT5-8000H;
- General Electric 9FB (at the time of conducting the study, the marketing of the GE 9FB-05 had not yet been launched, so this version was excluded);
- Alstom GT26 (at the time of conducting the study, the marketing of the 2011 upgrade of the GT26 had not yet been launched, so this version was excluded);
- Mitsubishi Heavy Industries 701F4; and
- Mitsubishi Heavy Industries 701G2.

In practice, the large GT market is, and is likely to remain, a generally competitive one in performance and price. It is considered likely that all the aforementioned gas turbines and their future versions or replacements may be relevant for inclusion within various scenarios of this study; however, in order to aid comparison between the scenarios, the choice of a single GT is considered preferable for this study.

The relatively recent increase in the number of 50Hz GTs with capacity above 300 MW would indicate that by 2020, such GTs may well be the norm for large CCGT plants. However, as highlighted below for certain of these larger GTs, a conservative approach has been taken in this assessment with regards to the probability of imminent development of high-hydrogen combustion versions of these GTs (a requirement for the pre-combustion scenarios).

Each of the aforementioned 50Hz GTs are briefly discussed with respect to the notional concept of a single machine suiting the requirements of all the scenarios presented in Section 1.3. Performance data presented is based on Gas Turbine World 2011.

2.2.1 Siemens SGT5-4000F and SGT5-8000H

Performance of the SGT5-4000F at ISO conditions are presented below;

Parameter	
Power Output	292MW
Simple Cycle Efficiency	39.8%
Heat Rate (kJ/kWh)	9039

Performance of the SGT5-8000H at ISO conditions is presented below:

Parameter	
Power Output	375MW
Simple Cycle Efficiency	40.0%
Heat Rate (kJ/kWh)	9001

2.2.1.1 Suitability for high H_2 content fuel

While the SGT5-4000F's 60Hz counterpart, the SGT6-5000F, is being considered extensively for Integrated Gasification Combined Cycle (IGCC) projects in the USA, the SGT5-4000F does not share the same type of combustion system and when asked at the commencement of the study, Siemens advised they were not actively developing the SGT5-4000F for syngas/H_2 combustion.

The combustion system on the SGT5-4000F differs in that it incorporates a single annular combustor with the burners arranged circumferentially. This is marketed as the hybrid burner ring (HBR) since, dependent on load, it can utilise either a premix or a diffusion system.

For the purposes of high-hydrogen content fuels, it is widely regarded that *silo* and *can* combustion systems are more suitable than annular combustors.

Siemens SGT5-8000H

The first (and currently only) SGT5-8000H was handed over as part of a commercial CCGT unit in mid-2011. While it may well become a common unit by 2020, it is currently uncertain whether a proven syngas/H_2 combustion version of this GT would be commercially available by that time. Siemens note, however, that the development of a syngas/hydrogen-capable version of the SGT5-8000H is targeted to meet the requirements of future IGCC projects that are under discussion. For a syngas/hydrogen-capable SGT5-8000H, the same can-type combustion system could be applied as is used for the 60 Hz SGT6-5000F. Nonetheless, of the gas turbines considered, the SGT5-8000H remains the most recently released and so for the purposes of the study it would be considered to be on the premature side to use it as the basis for modelling a technology step-change such as syngas/H_2 combustion.

2.2.2 General Electric GE9FB

Performance of the GE-9FB at ISO conditions are presented below;

Parameter	
Power Output	284MW
Simple Cycle Efficiency	37.9%
Heat Rate (kJ/kWh)	9512

2.2.2.1 Suitability for high H_2 content fuel

GE is actively developing the “FB” syngas combustion systems as part of a US Department of Energy funded programme. The “FA” syngas combustion systems that serve as predecessors have been in operation for more than 15 years on 60Hz GE 7FA gas turbines.

2.2.3 Alstom GT26

Performance of the GT26 at ISO conditions are presented below;

Parameter	
Power Output	296.4MW
Simple Cycle Efficiency	39.6%
Heat Rate (kJ/kWh)	9091

N.B Figures presented are based on operation with air quench cooler

2.2.3.1 Suitability for high H_2 content fuel

The GT26 combustion design has two sequential annular combustors, consisting of twenty-four burners each and separated by the HP Turbine. The sequential combustion burner system utilises EV (EnVironmental) burners followed by SEV (Sequential EnVironmental) burners. The use of the reheat mode via the SEV system is unique to the GT24 and GT26. The reheat technology provides the GT26 with a theoretical thermodynamic advantage and enables the machine to reach high output and efficiency with less emphasis on a higher firing temperature.

As far as the authors are aware, Alstom are not considering syngas combustion for the GT26. In addition, due to the sequential combustion system, commercially available GT-modelling software packages cannot model this GT on any fuel other than pure methane.

2.2.4 Mitsubishi Heavy Industry MHI701F4

Performance of the 701F4 at ISO conditions are presented below;

Parameter	
Power Output	312.1MW
Simple Cycle Efficiency	39.3%
Heat Rate (kJ/kWh)	9161

2.2.4.1 Suitability for high H_2 content fuel

The first MHI 701F4 only entered commercial operation in 2010. All active syngas combustion developments by MHI are on their G-class GTs.

2.2.5 Mitsubishi Heavy Industry MHI701G2

Performance of the 701G2 at ISO conditions are presented below;

Parameter	
Power Output	334.0MW
Simple Cycle Efficiency	39.5%
Heat Rate (kJ/kWh)	9105

2.2.5.1 Suitability for high H_2 content fuel

The MHI 701G2 uses steam cooling for its combustors and transition pieces and is inherently less flexible operationally as a result (slower start-up times, etc.). Consequently, with only slightly greater power output than the MHI 701F4, it is not being marketed in Europe and thus is not considered further in this study.

2.2.6 Reference Gas Turbine conclusion

With the GE 9FB being the only GT listed that is currently marketed in Europe and is actively being sought to be the basis for the development of a syngas gas turbine, it has been selected as the reference GT to be used within this study.

2.3 Site location and ambient conditions for modelling

The standard criteria used by the IEA GHG define the notional site as being a coastal site in the North East of the Netherlands. For the purposes of air dispersion modelling, a site in the vicinity of Eemshaven has been selected.

The typical ambient conditions used for performance modelling are specified within the IEA standard criteria[8] as being 9°C for the average dry-bulb temperature and 60% for the relative humidity. However, considering the decision to opt for cooling towers (discussed in the following section) the concurrent relative humidity is a significant parameter in the sizing of the cooling towers and consequently it was agreed with the IEA GHG that a more representative relative humidity value of 80% should be used. All full load and part load performance simulation runs were carried out at these selected design average ambient conditions.

2.4 Cooling Towers vs. Seawater Cooling

While the site has been defined within the IEA standard criteria as being coastal, many CCGT power station sites in the vicinity of the coast in the Netherlands do not utilise once-through seawater cooling. In addition, the majority of CCGT plants in Europe and around the world do not use once-through cooling. In order to make the findings of the study more applicable to the majority of plants/sites around the world, mechanical draught wet cooling towers have been selected. Hybrid cooling towers for plume abatement have not been selected due to the notional nature of the reference plant; the need for plume abatement is dependent on the potential impacts of the plume on adjacent facilities and infrastructure, which are unknown.

For consistency across all scenarios, the approach temperature between the ambient wet bulb temperature (a function of the defined relative humidity) and the cooling water supply temperature (i.e. the cold cooling water sent out from the cooling tower) was set at 7°C. This results in a design cooling water supply temperature of 14.36°C for all the scenarios and applications. The design cooling water temperature range (i.e. the rise in cooling water temperature between supply and return) was selected as 11°C, resulting in a design cooling water return temperature of 25.36°C.

2.5 Utilities

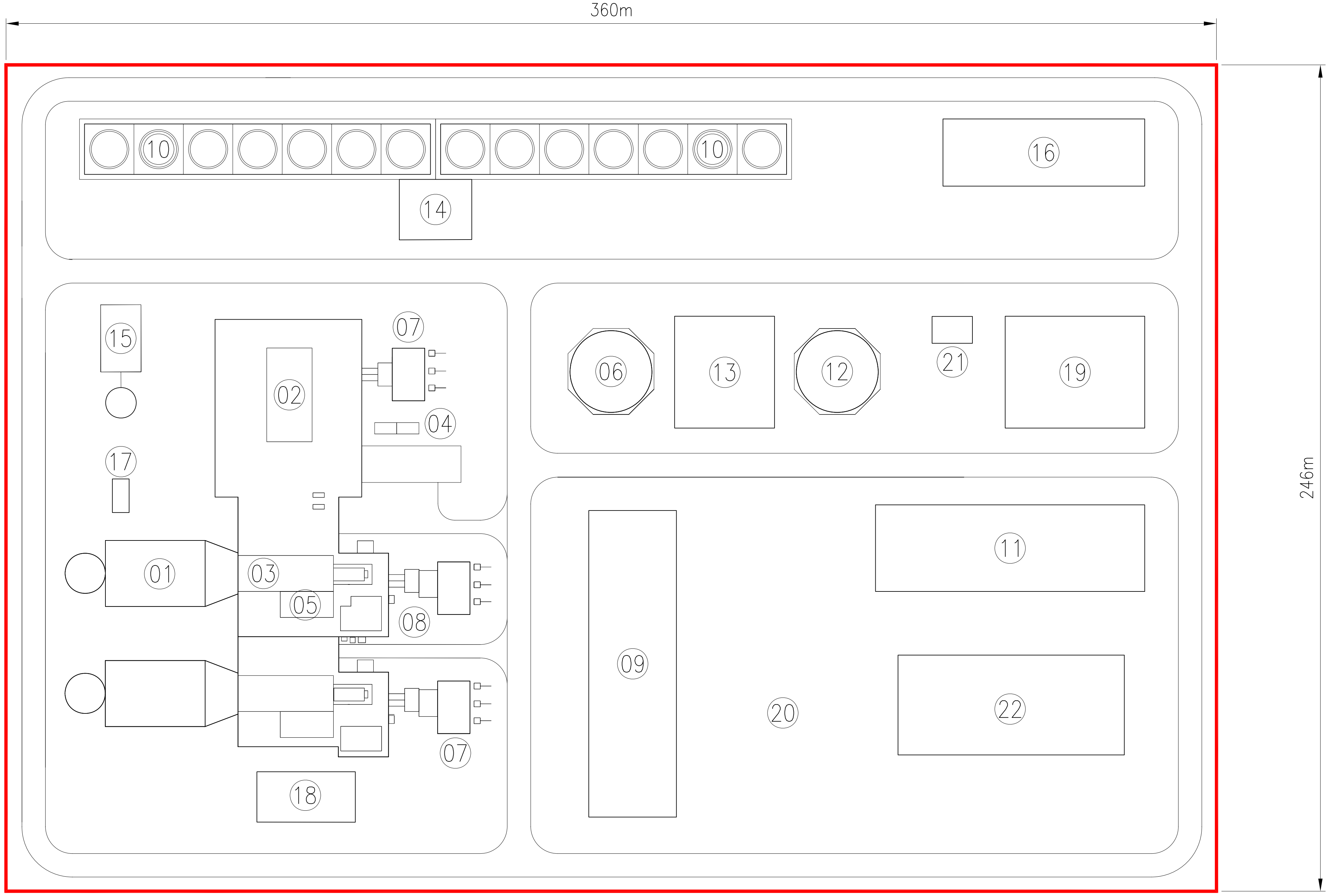
The provision of standard utilities associated with CCGT plant have been included in the cost estimation of the reference plant. These utility and support systems include:

- Nitrogen from cylinders for purging;
- Carbon dioxide from cylinders for fire suppression;
- Instrument air system supplied by package air compressors (2 x 100%) with nominal mass flow rate of 1 t/h;
- Service water system consisting of a 2 inch nominal bore pipe network;
- Water treatment plant including reverse osmosis and de-ionization plant for demineralised water production (production rate of 45 t/h);
- Fire water system supplied from the raw water tank, with one electrically driven firewater pump and one diesel driven;
- A package auxiliary boiler primarily for start up requirements; and
- An emergency diesel generator (2.5 MW) for safe shut down of the plant.

2.6 Layout Drawing

The layout of the reference CCGT plant is presented on the following page.

Project Number: | Drawing Number: | Revision:



LEGEND

01 HEAT RECOVERY STEAM GENERATOR	09 GI SWITCHYARD	17 EMERGENCY DIESEL GENERATORS
02 STEAM TURBINE AREA	10 COOLING TOWERS	18 CONTROL BUILDING
03 GAS TURBINE AREA	11 WAREHOUSE/MAINT./ADMIN	19 RAW-WATER PRE-TREATMENT
04 CO2 LOW PRESSURE STATION	12 RAW WATER/ FIREWATER STORAGE TANK	20 POSSIBLE LAYDOWN/OPEN STORAGE AREA
05 GAS TURBINE INLET FILTER	13 WATER TREATMENT BUILDING	21 FIRE FIGHTING PUMPHOUSE
06 DEMINERALIZED WATER STORAGE TANK	14 CW PUMPHOUSE	22 CAR PARKING
07 MAIN TRANSFORMER	15 AUXILIARY BOILER	
08 AUXILIARY TRANSFORMER	16 GAS CONDITIONING FACILITY	

BAR SCALE 1:1500

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Login: Stenhoff, Mark
Plot Date: 07/03/2012 12:09:19

Rev	Date	Description	By	Chk	App	Notes:

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Client:
IEA ENVIRONMENTAL PROJECTS LTD

Project:
CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title:
CCGT REFERANCE PLANT (NO CARBON CAPTURE)

Drawn: DD		Checked: RC	
Designed: DD		Approved: RC	
Date: 28/06/2011	Scale: 1/1500	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00010		Revision:

2.7 Reference Plant Performance Information at Full and Part Load

Estimated plant performance was investigated at design ambient conditions at both gas turbine base load and 40% load set points. The decision for an appropriate part load set point for the study was influenced by the intention to address a broad span of potential operational points. The part load set point was thus to represent an operational point at or near the minimum guaranteed load point, which implies emissions compliance. Due to the increased demand for flexible CCGTs, Parsons Brinckerhoff has witnessed a recent decrease in the guaranteed minimum CCGT load from the major OEMs. As a result, the 40% GT load, which equates to just under 50% CCGT load for the reference case, is deemed an appropriate part load scenario to investigate for the notional plant in 2020. It is worth noting that in practice, low CCGT loads could also be achieved by turning off one gas turbine train (as opposed to turn-down of both trains).

The CCGT cycle schematics including operational parameters are given in Figure 3 and Figure 4 for the base load and 40% GT load cases respectively. The key performance indicators are summarised below in Table 6 and Table 7.

Table 6 Scenario 1 overall performance summary at full load operation

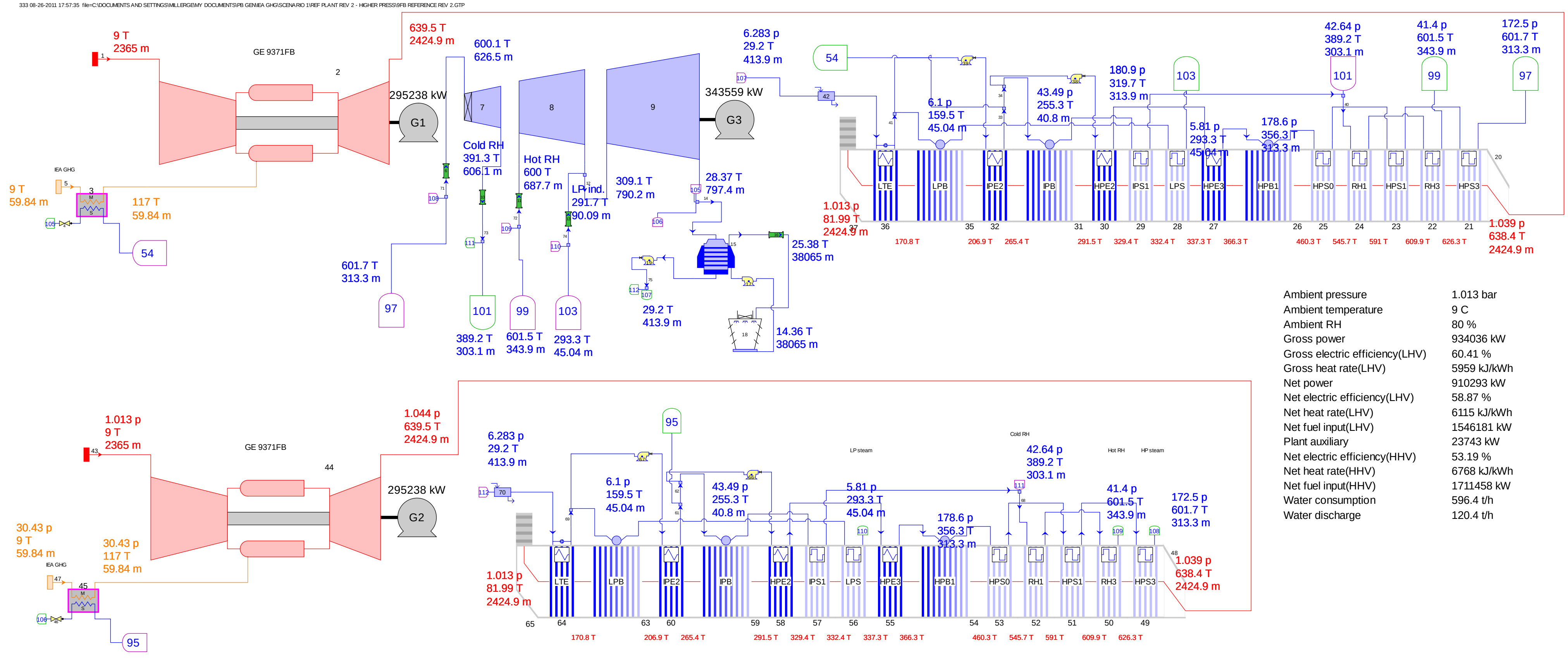
Parameter	Unit	Value
Gross Power Output	MW	934.0
Gas Turbines Gross Power Output	MW	590.5
Steam Turbine Gross Power Output	MW	343.5
Power Island Losses and Auxiliary Power	MW	23.7
Overall Net Power Output	MW	910.3
Natural Gas Fuel Consumption (LHV)	MJ/s	1546.2
Natural Gas Fuel Consumption (HHV)	MJ/s	1711.5
Overall Net Efficiency (LHV)	%	58.87
Overall Net Efficiency (HHV)	%	53.19
Raw Water Consumption	t/h	596.3
Water Discharge Rate	t/h	121.2
Total CO_2 Captured	kg/MWh	0
Total CO_2 Emitted	kg/MWh	348.3

Table 7 Scenario 1 overall performance summary at part load (40% GT load) operation

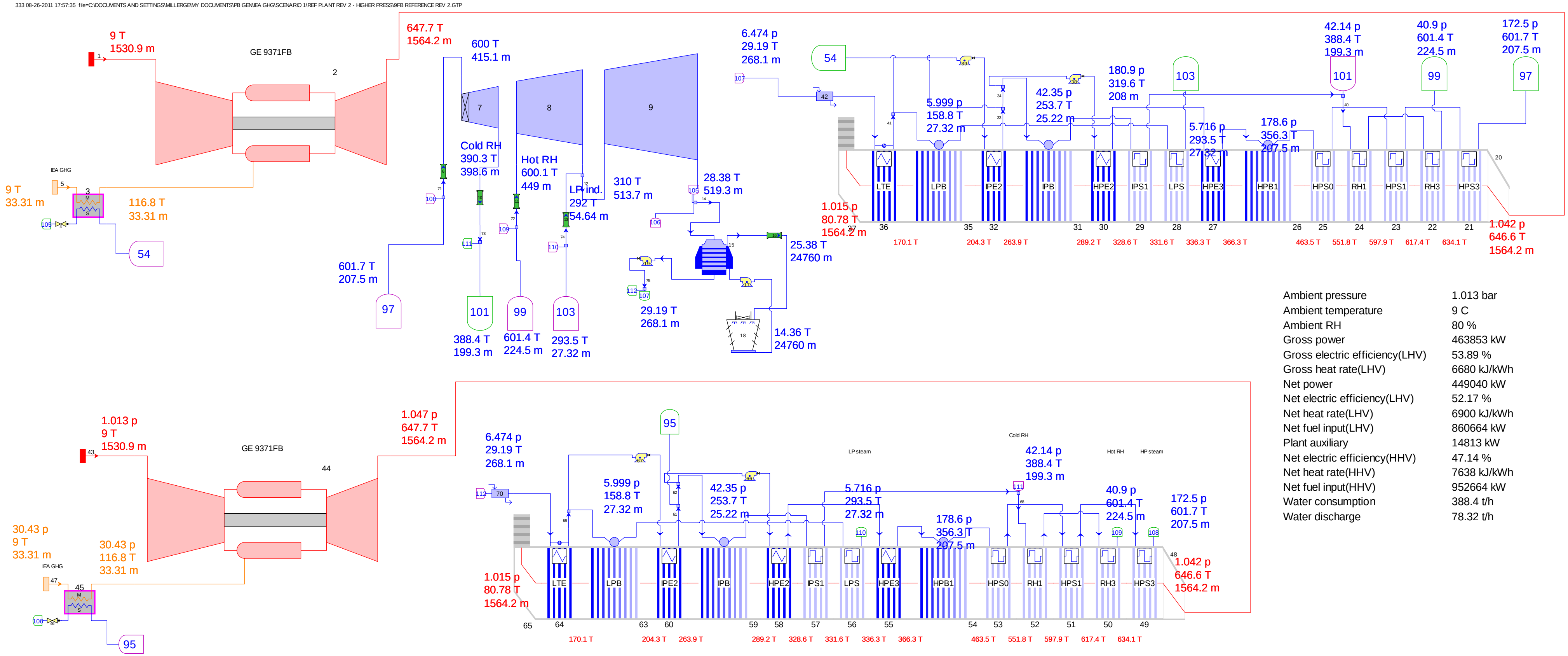
Parameter	Unit	Value
Gross Power Output	MW	463.9
Gas Turbines Gross Power Output	MW	239.0
Steam Turbine Gross Power Output	MW	224.9
Power Island Losses and Auxiliary Power	MW	14.8
Overall Net Power Output	MW	449.0
Natural Gas Fuel Consumption (LHV)	MJ/s	860.7
Natural Gas Fuel Consumption (HHV)	MJ/s	952.7

Parameter	Unit	Value
Overall Net Efficiency (LHV)	%	52.17
Overall Net Efficiency (HHV)	%	47.14
Raw Water Consumption	t/h	388.4
Water Discharge Rate	t/h	79.2
Total CO_2 Captured	kg/MWh	0
Total CO_2 Emitted	kg/MWh	393.0

bar | C
t/h | kJ/kg



Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	934036 kW
Gross electric efficiency(LHV)	60.41 %
Gross heat rate(LHV)	5959 kJ/kWh
Net power	910293 kW
Net electric efficiency(LHV)	58.87 %
Net heat rate(LHV)	6115 kJ/kWh
Net fuel input(LHV)	1546181 kW
Plant auxiliary	23743 kW
Net electric efficiency(HHV)	53.19 %
Net heat rate(HHV)	6768 kJ/kWh
Net fuel input(HHV)	1711458 kW
Water consumption	596.4 t/h
Water discharge	120.4 t/h



Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	463853 kW
Gross electric efficiency(LHV)	53.89 %
Gross heat rate(LHV)	6680 kJ/kWh
Net power	449040 kW
Net electric efficiency(LHV)	52.17 %
Net heat rate(LHV)	6900 kJ/kWh
Net fuel input(LHV)	860664 kW
Plant auxiliary	14813 kW
Net electric efficiency(HHV)	47.14 %
Net heat rate(HHV)	7638 kJ/kWh
Net fuel input(HHV)	952664 kW
Water consumption	388.4 t/h
Water discharge	78.32 t/h

3. CO_2 CAPTURE PROCESSES SUITABLE FOR GAS-FIRED POWER PLANTS

Capture of CO_2 emissions from gas fired power plants can be achieved by several methods, which typically are classified as either *post-combustion* or *pre-combustion*. A post-combustion technology is one which treats combustion gases as they exit the CCGT, prior to exhaust to atmosphere. Pre-combustion technologies remove carbon components of natural gas prior to combustion of the remaining hydrogen.

This section examines the current best available techniques for pre and post combustion, and presents a justification for the selection of the capture technologies examined in detail in the study. The section also provides some background about the CO_2 compression options available.

3.1 High Level Post Combustion Technology Options

Commercially available CO_2 capture technology options for post-combustion capture include:

- Chemical absorption;
- Physical absorption;
- Adsorption (Pressure/Temperature Swing);
- Gas membrane separation; and
- Cryogenic Distillation.

These technologies differ in their mode of separation of CO_2 from flue gas mixtures.

3.1.1 Chemical Absorption

Chemical and Physical absorption processes typically utilize liquid solvents for separation which is circulated between two distinct unit operations – absorption and desorption (or regeneration). Chemical absorption involves the reaction of CO_2 with a chemical solvent. This enhances the physical dissolution of CO_2 in the solvent. It is suitable for applications with low CO_2 partial pressures.

3.1.2 Physical Absorption

CO_2 dissolves in certain physical solvents. The driving force for separation in physical absorption is the partial pressure of CO_2 – with CO_2 compositions less than 15% on a volumetric basis, the pressurization requirements would typically make this option unattractive.

3.1.3 Adsorption processes

In adsorption, a solid medium separates CO_2 from the flue gas and the sorption and regeneration are typically achieved by cyclic changes in pressure or temperature in the same vessel. Many adsorption systems have the drawback of low selectivity thus resulting in an impure CO_2 product stream. As such, these systems are typically combined with further processing such as cryogenic distillation to achieve desired level of purity. In addition, the adsorption capacity of commercially available systems is quite low and may therefore be unsuitable for large scale applications with dilute flue gas streams.

3.1.4 Gas Membrane Separation

Membranes are specially manufactured materials that allow the selective permeation of a gas through them. The separation is driven by the pressure difference across the membrane. The compression requirements for pressurizing the flue gas streams from the gas turbine to required levels would make this option uneconomical.

3.1.5 Cryogenic Distillation

Cryogenic distillation involves liquefying the gaseous mixture and separating its components in a distillation column. The liquefaction process is energy intensive and is therefore only suitable for applications with high CO_2 concentrations.

3.2 Post-combustion capture technology selection

Amongst the above process options, only *chemical absorption* is suitable for the particularly low partial pressures of CO_2 typical of flue gas streams from gas-fired power plants (about 4vol% CO_2) with currently available technology. This is also the case even with flue gas recirculation (which can achieve CO_2 volumetric percentages of 8-9vol%).

3.2.1 Chemical Absorption Solvent Options

Amine solvents are common options for the chemical absorption of CO_2. MEA is a primary alkanolamine and has been used for the chemical absorption of CO_2 for several decades but at a smaller scale than what would be required for an 800 MWe power plant.

Tertiary alkanolamines like methyldiethanolamine (MDEA) have a higher absorption capacity than MEA but a slower rate of absorption. A number of solvent blends (such as those of MEA and other solvents like MDEA) are being investigated to optimize the capacity and absorption rates of solvents. Cyclic amines such as piperazine have also been found to have favourable absorption rates and have also been used to create special solvent blends.

Some proprietary solvents like the KS-1 developed by Kansai Electric Power Company (KEPCO) and Mitsubishi Heavy Industries (MHI) consist of hindered amine solvents where the base amine compound is chemically altered to improve its performance.

Other solvent compounds such as ammonia (in Alstom's Chilled Ammonia Process) and amino-acid salts (in Siemens proprietary CO_2 capture process) have been demonstrated to be viable for CO_2 capture.

3.2.2 Chemical Absorption Solvent Development

MEA has several advantages as a chemical solvent. Compared with most amine solvents it has high absorption rates, relatively low solvent costs, relatively low molecular weights and reasonable thermal stability. MEA has a particularly high solvent regeneration energy requirement which would impact the power plant's performance.

Other drawbacks of the MEA chemical absorption process include:

- Relatively high levels of corrosion especially at high CO_2 loadings;
- Significant solvent degradation rates in the presence of O_2, SO_x and $NO_{x;}$ and
- Vaporisation losses due to relatively high vapour pressure.

New solvents are being developed to address these issues. For instance, both KS-1 from MHI and amino-acid salts from Siemens offer lower energy demand for solvent regeneration. The latter also offers a solvent with near-zero vapour pressure and particular stability against oxygen degradation.

For the purposes of this study, it was decided that chemical absorption was the optimum post- combustion CO_2 capture method for the reasons outlined above.

3.3 High Level Pre Combustion Technology Options

For the pre-combustion scenarios considered, CO_2 volume fractions in the synthesis gas attain levels up to about 16vol% after condensate has been knocked out (downstream of the shift reactors). At such levels, more CO_2 capture technology options are available. These are as follows:

3.3.1 Adsorption (Pressure/Temperature Swing)

These systems are more suitable for systems at higher operating pressures. As such, they would perform better with the pre-combustion scenarios available as opposed to the post-combustion ones. The closest commercial application is the pressure swing adsorption process for hydrogen purification from synthesis gas. Some hydrogen fuel may be lost with the CO_2 stream. Another separation process such as cryogenic distillation could be used as well to further purify the CO_2 stream. This would lead to higher operating and capital costs.

3.3.2 Gas membrane separation

The pre-combustion case involves higher operating pressures which make membrane separation feasible. Scaling up this process is not deemed an issue because of its modular nature. However, this would not deliver typical economies of scale which may make it unattractive for large CO_2 capture applications. In addition, there would typically exist a trade off between CO_2 recovery rate and product purity. This is partly because of the observed challenges with the separation of H_2 and CO_2 using membranes[9].

3.3.3 Cryogenic Distillation

Even at pre-combustion CO_2 concentrations, the energy requirements for cooling down the synthesis gas streams make this option unattractive.

3.3.4 Chemical absorption

As discussed in Section 3.1, this technology is capable of capturing CO_2 at much lower partial pressures. The main drawback lies in the requirement for solvent regeneration, and the significant thermal energy required. The high partial pressure of CO_2 in this scenario may not directly translate to sufficiently large savings on thermal requirements.

3.3.5 Physical absorption

CO_2 separation via physical absorption becomes viable at the higher CO_2 concentrations achieved the in pre-combustion scenarios. The processes involved are also mature technologies. The performance of the absorption systems is based on the CO_2 partial pressure – thus higher operating pressures are preferred. The physical solvent could be regenerated by reducing the pressure or by heating the solvent thus adding further options to improve efficiency. The reforming process is operated at relatively high pressures (to attain sufficiently high pressures at the gas turbine inlet without the need for compression) which favours physical absorption. Figure 5 shows the general behaviour of chemical and physical solvents. At lower CO_2 partial pressures, chemical solvents have higher absorption capacity. Above a certain partial pressure, however, the physical solvents perform better. Different sources suggest different threshold partial pressures some as low as 4bara.

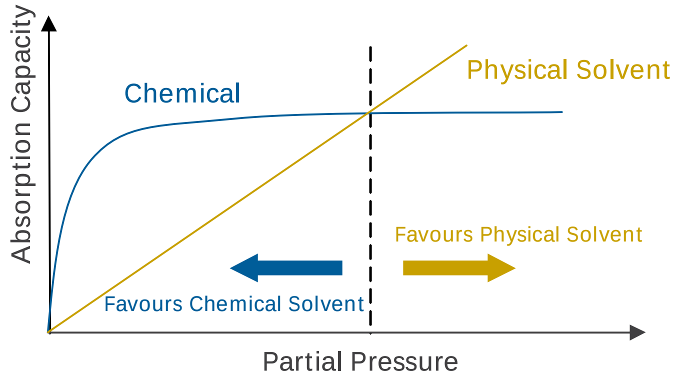


Figure 5 Comparison between Chemical and Physical Solvents[10]

3.4 Pre-combustion CO_2 capture technology selection

Both Chemical and Physical absorption are feasible options for this application. The partial pressure of CO_2 in the synthesis gas to the capture plant was about 6bara. Although this would be less than that typical for IGCC processes (about 20bara) where physical solvents are typically utilized, there still exists the opportunity to significantly reduce the steam requirements for solvent regeneration with physical absorption compared with chemical absorption. The additional steam made available could be used for improved heat integration and overall efficiency. It is noted that electrical power requirements for physical absorption processes are typically higher than that of chemical absorption.

Various physical solvents are available. Amongst these, Selexol has a relatively high CO_2 solubility and thus high absorption capacity, a very low vapour pressure (minimizing solvent losses), is non-toxic, non-corrosive and biodegradable.

3.5 Compression Technology Options

Reciprocating compressors have been used for the compression of CO_2 but at much smaller scales (about an order of magnitude smaller than the requirements for this study). Centrifugal compressors are, therefore, selected for large-scale CCS CO_2 compression applications. These compressors typically have higher efficiencies and reliabilities compared with the reciprocating type. These compressors could be categorized into two main branches:

- Single shaft in-line centrifugal compressors; and
- Multi-shaft integral-gear type.

Single shaft in-line centrifugal compressors are designed such that all the impellers are shrunk-on the shaft. As such the shaft speed is common for all the impellers. This configuration provides better maintenance access than the integral-gear type. Rolls Royce is one of the leading manufacturers of this type of compressor.

The multiple shaft integral gear compressor consists of a single bull gear coupled to a driver which rotates up to five shafts at the end of which are shrunk-on the impellers. As such, each shaft has its own speed based on the number of teeth of the pinion. This enables the optimization of impeller speeds. Man Diesel & Turbo is one of the leading manufacturers of this type of compressor.

The capacities of the standard range of production of multi-shaft integral gear compressors matched the capacities required for the CO_2 compression in this study and as a result, this type was selected for this study.

4. OVERVIEW OF SCENARIO 3 (CCGT POWER PLANT WITH POST-COMBUSTION CAPTURE)

This section provides an overview of *Scenario 3*, which is a post-combustion arrangement utilising chemical absorption. The section provides a process description, and details of the interfaces which the capture system has with the CCGT. A utilities summary is provided, along with a layout for the plant and performance data at full and part load.

For the purposes of deriving full performance data, the process design has been based on 35%wt MEA solvent, which can be accurately modelled in AspenPlus® to generate process stream data (Appendix D) and equipment sizes. This is referred to as *Scenario 3*. Where appropriate, the section also identifies the particular process improvements which can be achieved by utilisation of proprietary solvent systems, which are likely to be in widespread use in 2020 given the current rate of development. For the purposes of this study, Parsons Brinckerhoff have based our assessments on the MHI KM-CDR™ system, and Siemens PostCap™ system, and would thank MHI and Siemens for the provision of performance information in support of the study. Due to the confidential nature of this data, it has not been included in the report, however suggested performance improvements and cost information for proprietary systems are included, and are referred to as *Scenario 3b*.

It is important to note that flue gas CO_2 recovery using amine scrubbing has to date only been applied at a limited scale relative to the requirements of global power generation abatement. In designing a CO_2 recovery plant in the order of 3600 tonnes of CO_2 per day, the size of the process equipment has to be increased from the scale of equipment currently demonstrated (in the order of 500 tonnes of CO_2 per day). Parsons Brinckerhoff considers that all the equipment required for large CO_2 recovery plant has been commercially proven at smaller sizes and services, and that the increase in scale represents a significant albeit achievable technical challenge.

4.1 Process Description

The post-combustion chemical absorption flue gas capture process can be divided into two major parts: *absorption* and *desorption*. The chemical absorption process takes place in an *absorber* column while the desorption process takes place in a *stripper* column (otherwise termed a *regeneration* column). A simplified block flow diagram for the CO_2 capture process is presented in Section 4.3, and a full process flow diagram for the capture and compression plant is presented in Appendix A-2.

4.1.1 Flue Gas Fan and Direct Contact Cooler

In order to overcome the pressure drop through the capture plant, and to minimise any negative effects of backpressure on the GT exhaust, a flue-gas fan is required to provide a pressure lift of around 100mbar at full load. For the purposes of Scenario 3, the fan is an axial type, with a 9MW fixed speed (743rpm) drive.

Flue gas from the exhaust of each flue-gas fan is routed into a direct contact cooler (DCC) prior to the absorption process to cool the flue gas. The chemical absorption process is exothermic, and as such the process favours as low a flue gas temperature as possible at the inlet to the absorber. The DCC is therefore designed to cool the flue gas to the temperature at which it is water saturated, which is around 30^{o}C for typical CCGT exhaust gas conditions. The DCC is a rectangular, concrete column which utilises cooling water sprayed over a bed of stainless steel structured packing through which the flue gas rises. The cooling water is circulated through a heat exchanger, to remove waste heat to the cooling towers. Any water vapour which condenses during this process is removed from the circulating system at the suction side of the circulating pump.

4.1.2 Absorber column

The cooled flue gas enters the absorbers at the bottom of the absorber column while the solvent is introduced at the top of the column.

For the CO_2 absorber, concrete rectangular towers are proposed. There are a number of advantages of rectangular towers over cylindrical towers for large scale applications (i.e. columns with a diameter of greater than 18m). These include:

- Ease of construction of large rectangular towers of this size on-site as opposed to large cylindrical towers;
- Construction of the absorber is similar to the rectangular towers in large-scale seawater FGD plants, considered to be a commercially proven technique; and
- The low operating pressure does not necessitate cylindrical towers be used

It is important to note that the key factor to achieve the required process performance within the absorber is to ensure proper gas and liquid distribution in the column. Fluid distribution within the tower (especially the corners) is very important for ensuring the required performance when the rectangular type tower is applied.

The type of absorber which is proposed for the removal of CO_2 gas from the flue gas is a counter-flow packed tower. The key advantages of using a counter-flow packed tower is that the tower has a low pressure drop through the use of structured packing, high efficiency, low power consumption and high contact surface area relative to other types of absorbers available such as spray chamber, venturi scrubbers, ejectors and cross-flow packed scrubbers.

The concrete absorber is lined internally with a suitable corrosion resistant lining. The packing is 316L Stainless Steel. For the purposes of Scenario 3, Parsons Brinckerhoff have based the packing on Sulzer's structured Mellapak^{TM} 250Y, and have assumed a flooding capacity of 60%. It is noted that recent developments by Sulzer with respect to their proprietary Mellapak^{TM}CC^{TM} packing system offer improvements over the Mellapak250Y including a reduction in pressure drop over a given packing height, with no reduction in efficiency.

The overall absorber column height is determined by;

- the height of packing within the column required to achieve the CO_2 separation efficiency;
- Other column internals (solvent spray manifolds, water wash systems, packing supports);
- Requirement for free space at gas inlet to allow for flue gas dispersion within the column;
- Rich solvent sump at the column base.

Owing to the low partial pressure of the CO_2 in the flue gas, the column height is required to be around 83m for Scenario 3, when using 35%wt MEA solvent which has a lower absorption capacity relative to proprietary solvents. One of the main advantages of use of a *sterically hindered* solvent (such as MHI's proprietary KS-1 solvent) is that the absorption rate is improved over typical MEA solvent. The improved absorption rate is such that less absorption packing height is required to capture a given quantity of CO_2, and hence significant CAPEX savings can be realised through use of a shorter tower, and a shorter packed section. The required cross sectional area of the absorber is largely dictated by the requirement to minimise gas-side pressure drop, and to ensure adequate gas-solvent contact through the packing, so use of a proprietary solvent has less impact on the required absorber footprint.

Within the absorber, the cooled flue-gas flows upwards in a counter current direction to the solvent solution. Approximately 90% of the CO_2 from the flue gas is captured in the absorber. Solvent which is vaporised in the absorber column and present in the clean flue gas is captured by a water-wash section located at the top of the absorber column, and returned to the lower section of the absorber column. Siemens' amino acid salt technology has a near-zero vapour pressure, which is a key benefit that practically removes the requirement for water wash systems, with resultant CAPEX and OPEX savings.

The clean flue gas, which now contains mainly nitrogen, excess oxygen and low concentration of CO_2 is discharged from the top of the absorber column to atmosphere after reheating to 65ºC. For the purposes of this study, Parsons Brinckerhoff have proposed utilising waste heat from the condensate returned from stripper re-boilers for reheating the flue gas, as a means to improve overall thermal efficiency. Other options for gas reheating include using rotary gas-heaters (such as the Ljungström® regenerative gas-heater), although such designs typically involve some leakage between the clean / dirty gas stream, and a parasitic load associated with the drive. The reheating is required to allow for good plume air dispersion as per environmental requirements. A flue gas air quality model assessment will be required for individual sites to determine the suitable location, required temperature and height of stack for compliance with environmental regulations given stack emissions dispersion across the plant.

The solvent absorbs the CO_2 from the flue gas while interacting in the column. The flue gas leaves at the top of the column (largely free of CO_2), while the CO_2 *rich* solvent is discharged at the bottom of the column.

4.1.3 CO_2 stripper column

The rich solvent then passes to a stripper unit for regeneration. Here the solution is heated at low pressure by circulation through a reboiler which utilises LP steam to promote desorption (release) of the CO_2 from the solvent.

The thermal energy required for desorption of CO_2 from 35%wt MEA solvent is significant, owing to a high enthalpy of reaction with CO_2. This high enthalpy of reaction must be overcome to release the CO_2, and this represents a key disadvantage of MEA. Several capture technology OEM's have developed proprietary solvents which promise much lower thermal energy requirements for desorption (owing to the formation of different reaction products in the absorber columns), in the region of 70-80% that required for MEA.

CO_2 leaves the top of stripper column along with some traces of solvent. The solvent is separated from the CO_2 through condensation in a condenser. The lean hot solvent at the bottom of the stripper is then passed through a lean/rich solvent heat exchanger where rich solvent from the absorption tower is preheated, then fed back to the absorber to complete the cycle.

Since structured packing offers particular economic benefits in a large tower in terms of its large surface area, high capacity and low pressure drop, it is proposed that the CO_2 stripper also uses structured packing. The material of the packing and internals is assumed to be the same as the absorber (i.e. stainless steel 316).

4.1.4 CO_2 dehydration and compression

CO_2 exiting the stripper is compressed to a pressure of 74bara by means of a four stage compressor. The compression includes inter-stage cooling and knockout drums to remove and collect condensed water and dehydrate the CO_2 stream (using a Tri-ethylene Glycol (TEG) dehydrator) to the specification detailed in Table 4. The inter-stage cooling medium is circulating cooling water, itself cooled by a common cooling tower for the capture plant. The CO_2 is dehydrated to remove water to a suitably low level in order to reduce corrosion in the CO_2 transportation system. Beyond the critical point for CO_2 a final stage of compression is used to deliver a dense phase CO_2 stream at an assumed pipeline pressure of 110bara.

4.2 Interfaces with the CCGT

The main interfaces between the CCGT and carbon capture plant for Scenario 3 involve low pressure steam extraction for the Carbon Capture Plant re-boilers and HRSG flue gas diversion to the capture plant. The design of Scenario 3 is such that diversion of the flue gases from the HRSG stacks to the capture plant does not induce a backpressure on the gas turbine (which would result in performance reduction), due to the placement of the flue-gas fan which is positioned upstream of the direct contact cooler.

The primary difference in the CCGT steam cycle of this scenario relative to the reference scenario is the low pressure steam extraction required for the stripping column re-boilers of the capture plant. This extraction is taken from the crossover pipe between the MP and LP sections of the single steam turbine, and the extracted LP steam joins with supplementary superheated LP steam generated in the HRSG to supply the capture plant. The plant is designed such that when the CCS plant is not operating, excess steam cannot be routed through the ST (due to condenser size constraints), so it is not possible to 'overload' the ST in these circumstances. Instead, GT's are turned-down in order to limit steam production when the CCS plant is not operational.

The condensate return from the capture plant would typically be in excess of 120°C, and due to it representing a significant proportion of the boiler feed-water to the HRSG, the resulting increase in the low temperature economiser water inlet temperature would cause a HRSG exit gas temperature increase (relative to the reference case) of approximately 15°C. The notional design of this scenario incorporates a heat exchanger between the absorber exit gas (which requires heating for air dispersion) and the reboiler condensate of the capture plant. Such a heat exchanger has dual benefit in that a gas-gas heat exchanger is avoided (rotary gas-gas heat exchangers carry a large risk of leakage) and the reboiler return condensate temperature is significantly reduced, thereby reducing the HRSG exit gas temperature.

A summary of the main interface aspects between the CO_2 capture facility and CCGT plant is provided below:

- Diverter/isolation dampers installation in the main HRSG stacks at the point of exhaust gas extraction;
- Exhaust gas ducting from the HRSG main stack to the capture plant;
- Low pressure steam extraction and supply to the capture facility;
- Electrical power supply to the capture plant; and
- Control systems for both CCGT and capture plant within a common DCS.

In addition, the common facilities interfaces are:

- Raw water treatment and supply to cooling tower systems; and
- Fire fighting water supply and system.

4.3 Block Flow Diagram

A simplified block flow diagram for the CO_2 capture process is presented in Figure 6, and a full process flow diagram for the capture and compression plant is presented in Appendix A-2:

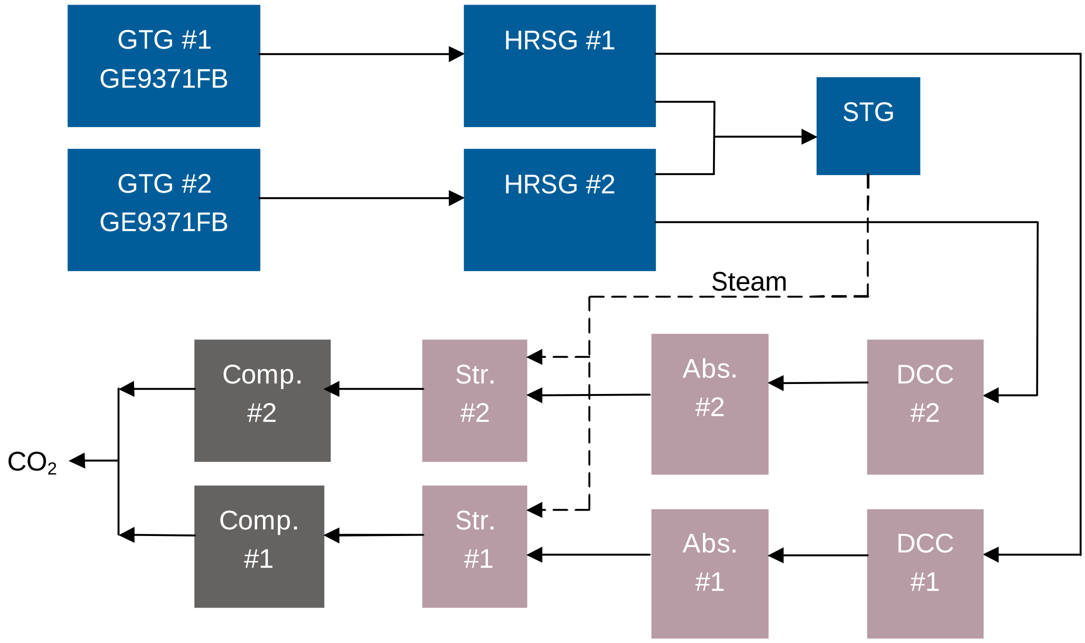


Figure 6 Scenario 3 Block Flow Diagram

4.4 Utilities Summary

The utility requirements for Scenario 3 are as follows;

Table 8 Utility Consumption of Scenario 3 (35% wt MEA soln.)

Utility	Unit	CCGT	Capture	Compression	Total
Electrical Power	MWe	19.4	24.8	26.6	70.8
Cooling Duty	MW	256.1	475.0	*Included in capture*	731.1
Cooling water	t/hr	20,223	32,898	3,728	56,849
Raw water	t/hr	313.2	593.6	*Included in capture*	906.8
LP Steam	t/hr	-	438.8	0	438.8
Demin. water	t/hr	1.9	12.54	0	14.4

When using a proprietary solvent / system, the consumption of certain utilities is reduced from that required when using 35%wt MEA. The utility requirements for Scenario 3b (i.e. a proprietary solvent system) are as follows;

Table 9 Utility Consumption of Scenario 3b (Typical Proprietary solvent)

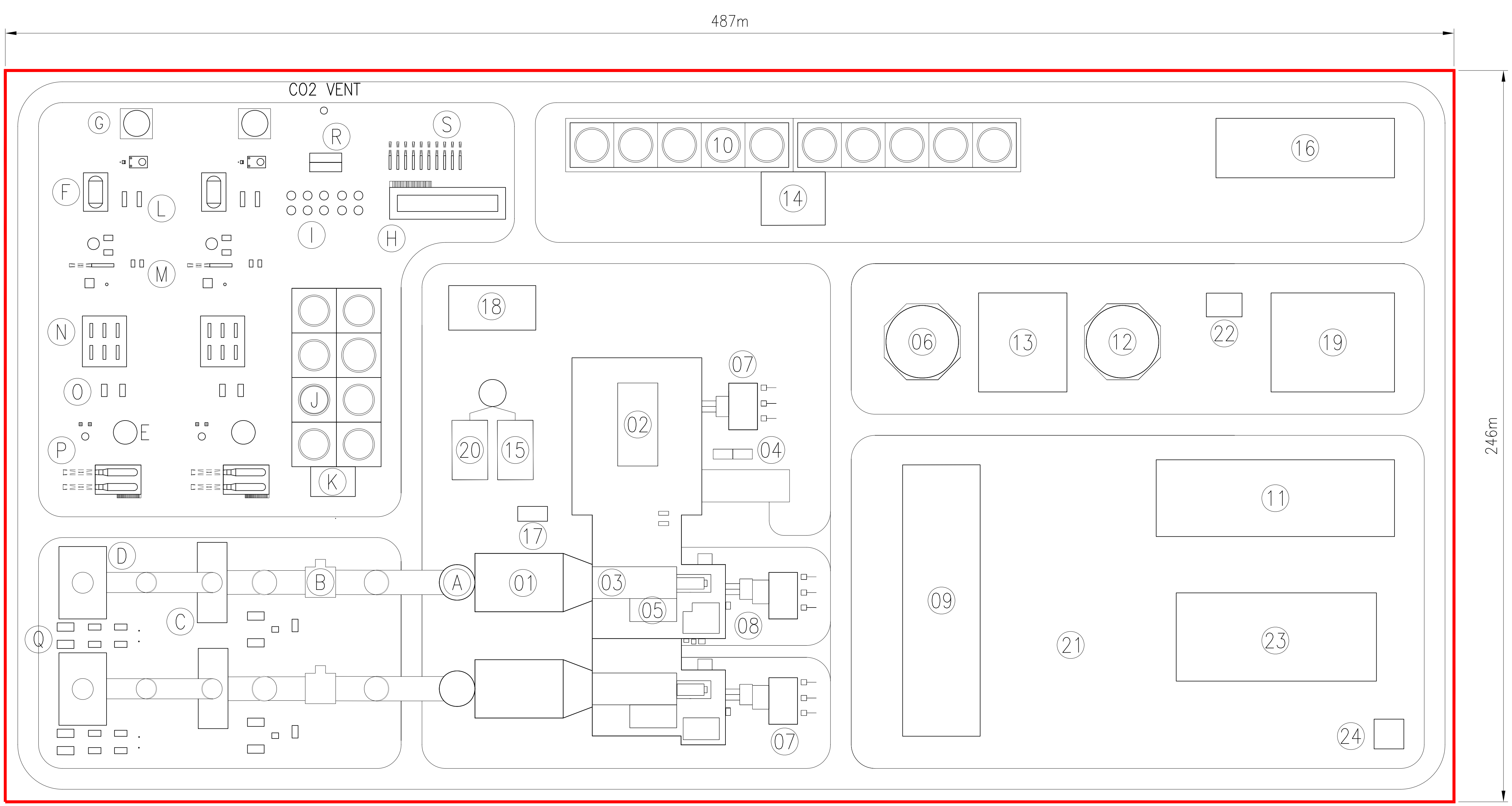
Utility	Unit	CCGT	Capture	Compression	Total
Electrical Power	MWe	20.2	23.5	26.5	70.2
Cooling Duty	MW	322.1	404.3	*Included in capture*	726.4
Cooling water	t/hr	24,470	28,290	3,729	56,489
Raw water	t/hr	394.4	506.8	*Included in capture*	901.2
LP Steam	t/hr	-	353.8	0	353.8
Demin. water	t/hr	1.90	12.54	0	14.4

** Demineralised water requirements are based on proprietary MEA based solvent systems which require column water wash sections.*

4.5 Layout Drawing

A layout drawing for Scenario 3 is shown on the following page. The drawing provides an indication of the capture plant layout relative to the full power plant site to show interfaces between the power generation equipment and the capture plant.

Layouts are intended primarily to provide an indication of plant footprint and possible interfaces. Details are expected to vary depending on the equipment provider, site location and further detailed design development.



LEGEND

01	HEAT RECOVERY STEAM GENERATOR	09	GI SWITCHYARD	17	EMERGENCY DIESEL GENERATORS	A	STACK	I	KNOCKOUT DRUMS	Q	DCC PUMPS & COOLERS & ABSORBER PUMPS
02	STEAM TURBINE AREA	10	COOLING TOWERS	18	CONTROL BUILDING	B	BLOWER	J	COOLING TOWERS	R	TEG DEHYDRATION PACKAGE
03	GAS TURBINE AREA	11	WAREHOUSE/MAINT./ADMIN	19	RAW WATER PRE-TREATMENT	C	DIRECT CONTACT COOLER	K	CW PUMP HOUSE	S	COMPRESSOR INTER-STAGE COOLERS
04	CO2 LOW PRESSURE STATION	12	RAW WATER/ FIREWATER STORAGE TANK	20	AUXILIARY BOILER FOR CCS	D	ABSORBER	L	LEAN SOLVENT COOLERS		
05	GAS TURBINE INLET FILTER	13	WATER TREATMENT BUILDING	21	POSSIBLE LAYDOWN/OPEN STORAGE AREA	E	STRIPPER	M	SOLVENT STORAGE PUMPS		
06	DEMINERALIZED WATER STORAGE TANK	14	CW PUMPHOUSE	22	FIRE FIGHTING PUMPHOUSE	F	RECLAIMER	N	SOLVENT CROSS EXCHANGERS		
07	MAIN TRANSFORMER	15	AUXILIARY BOILER	23	CAR PARK	G	SOLVENT STORAGE TANK	O	LEAN SOLVENT PUMPS		
08	AUXILIARY TRANSFORMER	16	GAS CONDITIONING FACILITY	24	GATE HOUSE	H	CO2 COMPRESSOR HOUSE	P	REBOILERS		

0 25m 50m 75m 100m

BAR SCALE 1:1500

Rev	Date	Description	By	Chk	App	Notes:

PARSONS BRINCKERHOFF
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Project: CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title: CCGT WITH POST COMBUSTION CO2 CAPTURE AND COMPRESSION PLANT

Drawn: DD		Checked: NS	
Designed: DD		Approved: NS	
Date: 05/08/2011	Scale: 1/1500	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00011		Revision: 1

4.6 Plant Performance data at full and part-load

Table 10 and Table 11 show the overall performance summary for Scenario 3 for full load and part load operations respectively.

Table 10 Scenario 3 (35% wt MEA soln.) overall performance summary at full load operation

Parameter	Unit	Value
Gross Power Output	MW	860.12
Gas Turbines Gross Power Output	MW	590.31
Steam Turbine Gross Power Output	MW	269.81
Power Island Losses and Auxiliary Power	MW	19.4
Carbon Capture Plant Auxiliary Power (inc. CO_2 comp.)	MW	51.4
CO_2 Compressor Power	MW	26.6
Overall Net Power Output	MW	789.3
Natural Gas Fuel Consumption (LHV)	MJ/s	1546.6
Natural Gas Fuel Consumption (HHV)	MJ/s	1711.9
Overall Net Efficiency (LHV)	%	51.04
Overall Net Efficiency (HHV)	%	46.11
Carbon Dioxide Captured	t/h	288
Carbon Dioxide Capture Efficiency	%	89.9
Stripper Reboiler Duty	MWth	267.9
Specific Heat Duty for CO_2 Captured	kJ/kg CO_2	3347.0
Stripper Condenser Duty	MWth	-67.4
Raw Water Consumption	t/h	906.8
Water Discharge Rate	t/h	334.4
Total CO_2 Captured	kg/MWh	365.0
Total CO_2 Emitted	kg/MWh	41.0

Table 11 Scenario 3 (35% wt MEA soln.) overall performance summary at part load (40% GT load) operation

Parameter	Unit	Value
Gross Power Output	MW	422.47
Gas Turbines Gross Power Output	MW	239.32
Steam Turbine Gross Power Output	MW	183.14
Power Island Losses and Auxiliary Power	MW	14.6
Carbon Capture Plant Auxiliary Power (inc. CO_2 comp.)	MW	26.0
CO_2 Compressor Power	MW	14.1*
Overall Net Power Output	MW	381.8
Natural Gas Fuel Consumption (LHV)	MJ/s	854.3
Natural Gas Fuel Consumption (HHV)	MJ/s	945.6
Overall Net Efficiency (LHV)	%	44.69
Overall Net Efficiency (HHV)	%	40.38
Carbon Dioxide Captured	t/h	154
Carbon Dioxide Capture Efficiency	%	89.9

Parameter	Unit	Value
Stripper Reboiler Duty	MWth	144.9
Specific Heat Duty for CO_2 Captured	kJ/kg CO_2	3379.6
Stripper Condenser Duty	MWth	-37.8
Raw Water Consumption	t/h	538.4
Water Discharge Rate	t/h	179.5
Total CO_2 Captured	kg/MWh	404.4
Total CO_2 Emitted	kg/MWh	45.4

** CO_2 compression auxiliary power at 40% load is based on operation of one compressor train at/near full-load to service two part-load CO_2 capture trains. The minimum turndown of CO_2 compressors is about 70% and lower loads would require recirculation of compressed CO_2. CO_2 compressor power at part load operation of both CO_2 compressor trains would correspond to an auxiliary power demand of around 18.6MW.*

Table 12 and Table 13 show the overall performance summary for Scenario 3b for full load and part load operations respectively, and indicate the typical performance improvements which may be achieved through utilisation of a proprietary solvent system.

Table 12 Scenario 3b (Typical Proprietary solvent) overall performance summary at full load (100% load) operation

Parameter	Unit	Value
Gross Power Output	MW	874.20
Gas Turbines Gross Power Output	MW	590.00
Steam Turbine Gross Power Output	MW	284.20
Power Island Losses and Auxiliary Power	MW	20.2
Carbon Capture Plant Auxiliary Power (inc. CO_2 comp.)	MW	50.1
CO_2 Compressor Power	MW	26.5
Overall Net Power Output	MW	803.95
Natural Gas Fuel Consumption (LHV)	MJ/s	1546.8
Natural Gas Fuel Consumption (HHV)	MJ/s	1712.1
Overall Net Efficiency (LHV)	%	51.98
Overall Net Efficiency (HHV)	%	46.96
Carbon Dioxide Captured	t/h	289
Carbon Dioxide Capture Efficiency	%	90
Stripper Reboiler Duty	MWth	216.6
Specific Heat Duty for CO_2 Captured	kJ/kg CO_2	2700
Raw Water Consumption	t/h	901.2
Water Discharge Rate	t/h	333.2
Total CO_2 Captured	kg/MWh	359.2
Total CO_2 Emitted	kg/MWh	39.9

Table 13 Scenario 3b (Typical Proprietary solvent) overall performance summary at part load (40% GT load) operation

Parameter	Unit	Value
Gross Power Output	MW	429.84

Parameter	Unit	Value
Gas Turbines Gross Power Output	MW	239.34
Steam Turbine Gross Power Output	MW	190.50
Power Island Losses and Auxiliary Power	MW	15.4
Carbon Capture Plant Auxiliary Power (inc. CO_2 comp.)	MW	25.3
CO_2 Compressor Power	MW	14.2*
Overall Net Power Output	MW	389.2
Natural Gas Fuel Consumption (LHV)	MJ/s	854.8
Natural Gas Fuel Consumption (HHV)	MJ/s	946.1
Overall Net Efficiency (LHV)	%	45.53
Overall Net Efficiency (HHV)	%	41.14
Carbon Dioxide Captured	t/h	160
Carbon Dioxide Capture Efficiency	%	89.8
Stripper Reboiler Duty	MWth	119.9
Specific Heat Duty for CO_2 Captured	kJ/kg CO_2	2700
Raw Water Consumption	t/h	535.2
Water Discharge Rate	t/h	178.9
Total CO_2 Captured	kg/MWh	410.6
Total CO_2 Emitted	kg/MWh	46.6

** CO_2 compression auxiliary power at 40% load is based on operation of one compressor train at/near full-load to service two part-load CO_2 capture trains. The minimum turndown of CO_2 compressors is about 70% and lower loads would require recirculation of compressed CO_2. CO_2 compressor power at part load operation of both CO_2 compressor trains would correspond to an auxiliary power demand of around 18.6MW.*

4.7 Waste generated in the Power Plant and CCP processes

Main effluent streams from the Power Plant and CCP with their associated waste volumes are shown in Table 14 and Table 15.

Table 14 Waste generated by Power Plant (Scenario 3)

No.	Description	Unit	Value
1	Cooling water blow-down from ST condenser cooling tower	t/hr	62.16
2	Blow-down from HRSG drums	t/hr	1.9

Table 15 Waste generated by Capture and Compression Plant (Scenario 3)

No.	Description	Unit	Value
1	Cooling water blow-down from CCS plant cooling towers	t/hr	115.5
2	Amine waste	t/hr	0.9
3	Condensate waste from CO_2 compression	t/hr	4.7*
4	Direct contact cooler condensed water	t/hr	145.8*

** DCC / Compressor waste water is treated prior to discharge*

The waste streams from the Power Plant and CCP when utilising a proprietary system are shown in Table 16 and Table 17. It should be noted that the amount of amine waste is substantially reduced when using proprietary solvents, owing to inhibitors which improve the resistance of the solvents to impurities such as oxides of sulphur and nitrogen. Typically this amine waste is incinerated, and so the reduced quantity results in lower disposal costs.

Table 16 Waste generated by Power Plant (Scenario 3b)

No.	Description	Unit	Value
1	Cooling water blow-down from ST condenser cooling tower	t/hr	78.4
2	Blow-down from HRSG drums	t/hr	1.9

Table 17 Waste generated by Capture and Compression Plant (Scenario 3b)

No.	Description	Unit	Value
1	Cooling water blow-down from CCS plant cooling towers	t/hr	98.1
2	Amine waste	m^3/yr	~150
3	Condensate waste from CO_2 compression	t/hr	4.7
4	Direct contact cooler condensed water	t/hr	145.8

5. OVERVIEW OF SCENARIO 4 (COMBINED CYCLE PLANT WITH FLUE GAS RECIRCULATION POST-COMBUSTION CAPTURE)

This section provides an overview of Scenario 4, which is a post-combustion arrangement utilising Flue Gas Recirculation (FGR), otherwise termed Exhaust Gas Recirculation (EGR). Flue Gas Recirculation involves recycling a portion of the exhaust gases from the power plant back to the inlet of the compressor section for the GT while the remainder is sent to the carbon capture plant. The purpose of the recycle stream is to concentrate the CO_2 level in the flue gas being treated by the carbon capture plant, which improves the efficiency of the capture process and reduces the volumetric flow into the capture plant (potentially reducing the size, and associated cost of the capture plant).

Otherwise, the capture technology applied for Scenario 4 is broadly similar to Scenario 3 which is a post-combustion arrangement utilising chemical absorption using 35%wt MEA solvent.

A number of the leading OEM's for gas turbine technology are actively investigating the benefits and impacts of flue gas recirculation for post-combustion capture, notably ALSTOM, and General Electric.

The section provides a process description and details of the interfaces which the capture system has with the CCGT. A utilities summary is provided, along with a layout for the plant and performance data at full and part load.

5.1 Process Description

A simplified block flow diagram for the CO_2 capture process is presented in Section 5.3, and a full process flow diagram for the capture and compression plant is presented in Appendix A-3.

5.1.1 Flue Gas Fans and Direct Contact Coolers

Flue gas which exhausts from each HRSG is divided into two equal streams (by volume); one stream is returned to the inlet of each gas turbine compressor and the other stream is sent to the capture plant.

Each stream has a flue gas fan in order to overcome the pressure drop and to control flow-rates. It is proposed that flows are controlled and balanced using inlet-guide vanes on the fans, although if fine control is required, then variable speed drives or additional control dampers may also be an option. It is important that the recycle system does not impose a back-pressure on the exhaust of the GT (which would detrimentally affect performance), and as such the control system for the recycle system is required to be suitably sophisticated.

Both streams include a DCC to cool the flue gas down to the temperature required for processes downstream. The flue gas returning to the inlet of the gas turbine air compressor is cooled to 20°C. By cooling the recycle gas, the compression efficiency improves over that which would be achieved compressing warm exhaust gas. Flue gas from the DCC will be saturated with moisture during the direct contact water scrubbing process. The water droplets in the gas are removed by mean of a moisture separator before mixing with fresh air from atmosphere to produce combustion air for the GTs.

As per Scenario 3, the flue gas sent to the carbon capture plant is cooled to around 30°C.

Both DCCs are smaller in size than that required for Scenario 3. The reduction in volumetric flow-rate caused by splitting of the streams means that a column with a smaller cross sectional area can be utilised. This reduction in cross sectional area is such that a cylindrical tower can be used (the required diameter is around 14m which is considered practical for construction), which results in a CAPEX cost saving per column of around 45% over that of Scenario 3.

5.1.2 Absorber Column

By re-circulating flue gas through the gas turbine, the concentration of CO_2 in the flue gas entering the absorber is increased. A comparison of the flue gas composition at the inlet of the absorber in Scenario 3 and Scenario 4, is shown in Table 18:

Table 18 Comparison of absorber inlet flue gas conditions (Scenario 3 / Scenario 4)

	Scenario 3 Flue Gas to Absorber	Scenario 4 Flue Gas to Absorber
Temperature, °C	33.00	33.07
Pressure, barg	0.05	0.05
Mole Percent, %		
H_2O	4.78	4.80
MEA	0.00	0.00
CO_2	**4.46**	**9.03**
Ar	0.89	0.97
O_2	12.28	4.40
N_2	77.60	80.80

The CO_2 concentration in the flue gas without recirculation (i.e. Scenario 3) is 4.46%mol, but by incorporating the recirculation process, the concentration is increased to 9.03%mol. This has a number of related benefits. The higher CO_2 concentration improves the CO_2 capture process by reducing the required residence time in the absorber column, and consequently reduces the required packing height and permits use of a shorter column. A further benefit is that the required amine solvent recirculation rate can also be reduced which results in lower heat requirement for the solvent regeneration process. The stripper reboiler duty for Scenario 4 at base load is approximately 248MWth, which equates to around 92% of that for Scenario 3.

The lower volumetric flue gas flow rates to the capture plant in Scenario 4 means the size of some other equipment can also be reduced such as the main flue gas fans, lean-rich heat exchangers and solvent recirculation pumps.

Auxiliary power consumption for the capture process is also lower for Scenario 4 relative to Scenario 3 because of smaller equipment sizes (and associated drives) of the blowers and pumps.

However, the GT performance for Scenario 4 is marginally worse than Scenario 3, caused by the higher combustion air temperature into the GTs. The flue gas recirculated at 20°C is mixed with ambient air at 9°C producing a stream of mixed combustion air at 14.4°C which is 5.4^{o}C hotter than the combustion air for Scenario 3. The increase in the temperature results in a 0.6% (point basis) efficiency penalty for Scenario 4. GT gross LHV efficiencies for Scenarios 3 and 4 are 37.98% and 37.39% respectively.

Since warm air has a lower density than cold air, Scenario 4 has a lower mass air flow than Scenario 3, which results in a reduction in fuel flowrate into the GT to maintain the same air-fuel ratio and flame temperature. Operating at a lower fuel rate is equivalent to part load operation performance, hence the reduction in the efficiency.

5.2 Interfaces with the CCGT

The main interfaces for Scenario 4 are broadly similar to that described for Scenario 3. The main additional interface required for Scenario 4 is the duct work from DCC to the gas turbine air intake system for the flue gas recirculation. It is proposed that the recycled gas and the fresh air drawn from atmosphere are mixed together via a duct air mixer located between the GT compressor air intake filters and compressor air inlet.

It is noted that there may be further modifications required to the gas turbine combustors, to ensure that operability, turndown, emission levels and combustion efficiency remain unaffected in comparison with utilising fresh air. The nature of any such modifications are the subject of ongoing investigation by the major gas turbine OEM's.

5.3 Block Flow Diagram

A simplified block flow diagram for the CO_2 capture process is presented in Figure 7, and a full process flow diagram for the capture and compression plant is presented in Appendix A-3:

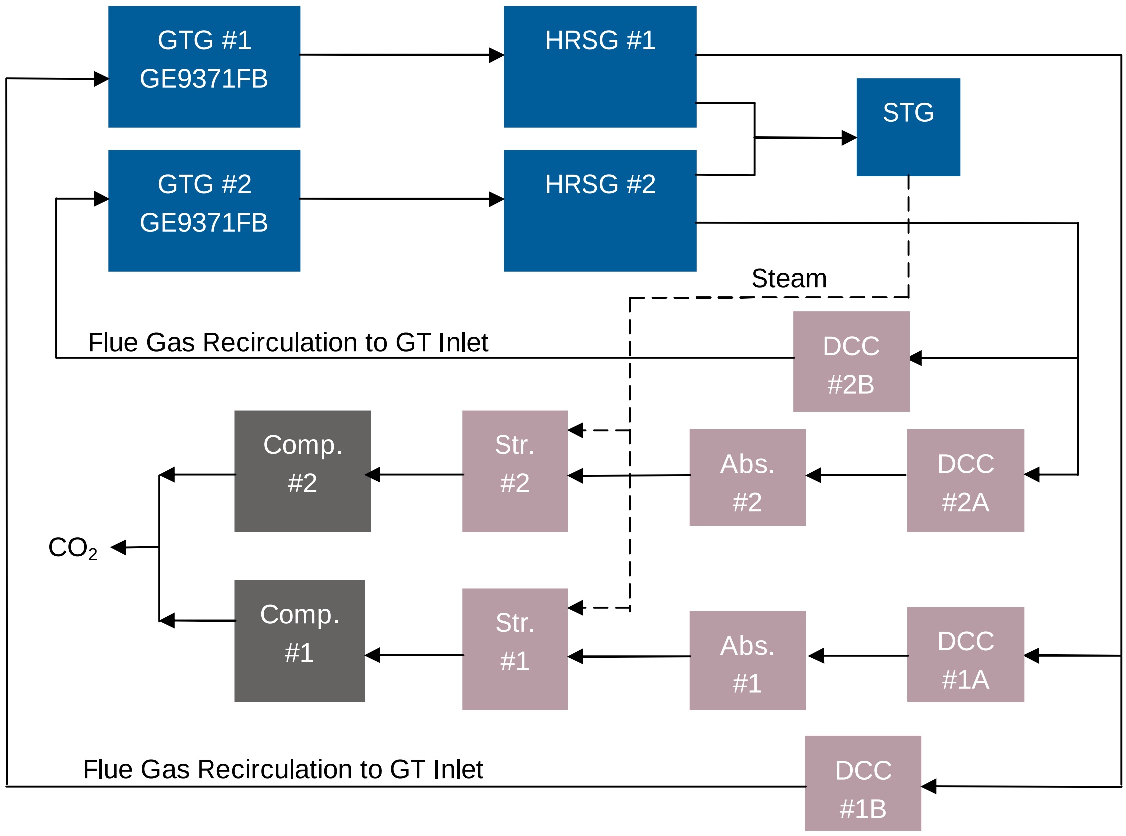


Figure 7 Scenario 4 Block Flow Diagram

5.4 Utilities Summary

The utility requirements for Scenario 4 are as follows;

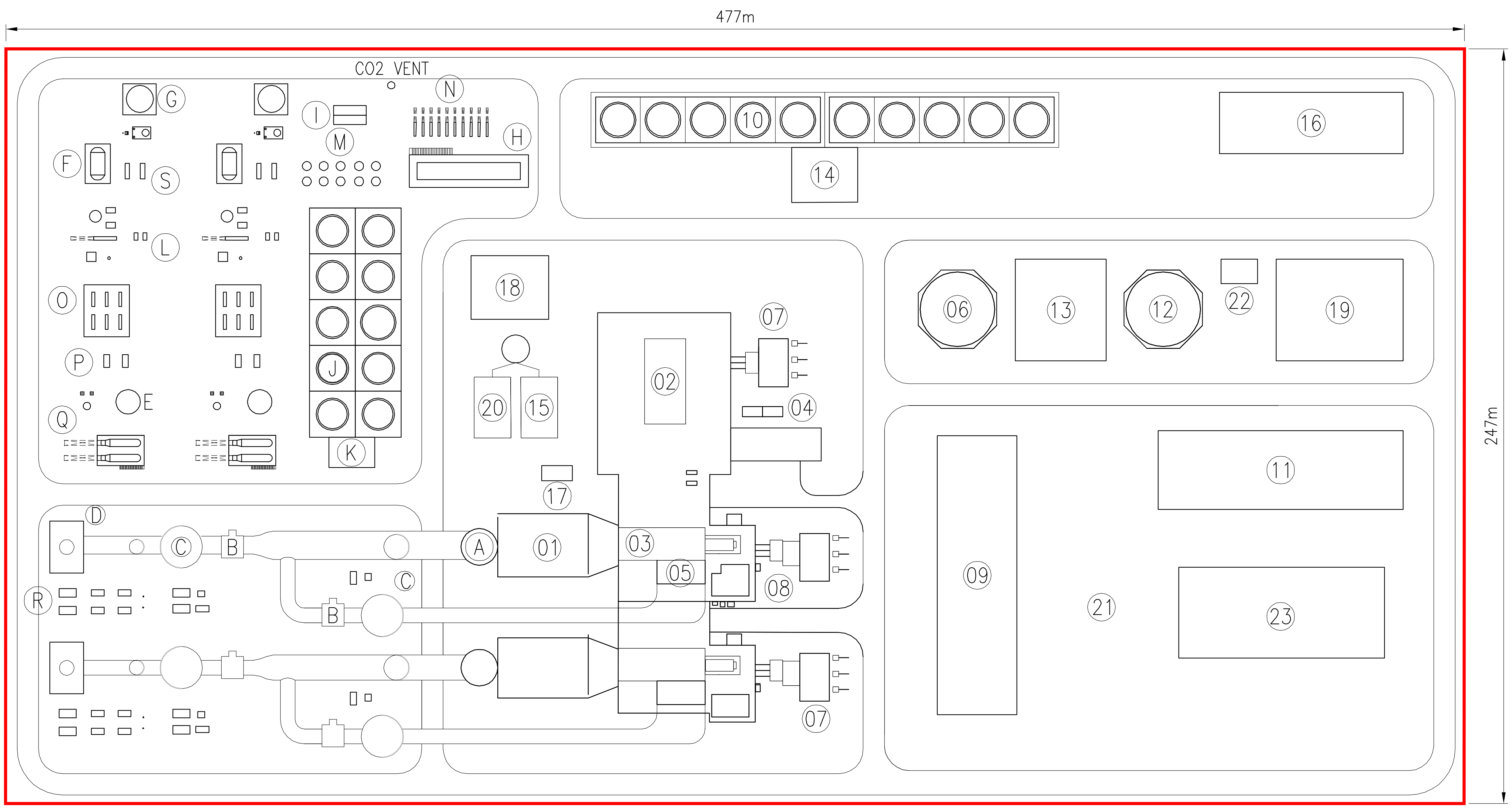
Table 19 Utility Consumption of Scenario 4

Utility	Unit	CCGT	Capture	Compression	Total
Electrical Power	MWe	19.4	19.5	26.2	65.1
Cooling Duty	MW	284.3	505.9	*Included in Capture*	790.2
Cooling water	t/hr	21,893	36,096	3,689	61,678
Raw water	t/hr	355.9	638.9	*Included in Capture*	994.8
LP Steam	t/hr	-	406.4	0	406.4
Demin. water	t/hr	1.9	7.78	0	9.68

5.5 Layout Drawing

A layout drawing for Scenario 4 is shown on the following page. The drawing provides an indication of the capture plant layout relative to the full power plant site to show interfaces between the power generation equipment and the capture plant.

Layouts are intended to primarily an indication of plant footprint and possible interfaces. Details are expected to vary dependent on the equipment provider, site location, and further detailed design development.



LEGEND

01	HEAT RECOVERY STEAM GENERATOR	10	COOLING TOWERS	19	RAW WATER PRE–TREATMENT	A	STACK	L	SOLVENT STORAGE PUMPS
02	STEAM TURBINE AREA	11	WAREHOUSE/MAINT./ADMIN	20	AUXILIARY BOILER FOR CCS	B	BLOWER	M	KNOCKOUT DRUMS
03	GAS TURBINE AREA	12	RAW WATER/ FIREWATER STORAGE TANK	21	POSSIBLE LAYDOWN/OPEN STORAGE AREA	C	DIRECT CONTACT COOLER	N	COMPRESSOR INTER–STAGE COOLERS
04	CO2 LOW PRESSURE STATION	13	WATER TREATMENT BUILDING	22	FIRE FIGHTING PUMPHOUSE	D	ABSORBER	O	SOLVENT CROSS EXCHANGERS
05	GAS TURBINE INLET FILTER	14	CW PUMPHOUSE	23	CAR PARK	E	STRIPPER	P	LEAN SOLVENT PUMPS
06	DEMINERALIZED WATER STORAGE TANK	15	AUXILIARY BOILER			F	RECLAIMER	Q	REBOILERS
07	MAIN TRANSFORMER	16	GAS CONDITIONING FACILITY			G	SOLVENT STORAGE TANK	R	DCC PUMPS & COOLERS & ABSORBER PUMPS
08	AUXILIARY TRANSFORMER	17	EMERGENCY DIESEL GENERATORS			H	CO2 COMPRESSOR HOUSE	S	LEAN SOLVENT COOLERS
09	GI SWITCHYARD	18	CONTROL BUILDING			I	TEG DEHYDRATION PACKAGE		
						J	COOLING TOWERS		
						K	CW PUMP HOUSE		

0 20m 40m 60m 80m

BAR SCALE 1:1500

Rev	Date	Description	By	Chk	App	Notes:

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Project: CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title: CCGT WITH RECIRCULATION AND POST COMBUSTION CO2 CAPTURE AND COMPRESSION PLANT

Drawn: DD		Checked: RC	
Designed: DD		Approved: RC	
Date: 07/07/2011	Scale: 1/1500	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00012		Revision:

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\Z. Drawings\1. Current\CO2 Capture\00012.dwg

Login: Brindley, Barry
Plot Date: 17/11/2011 10:49:29

Project Number | Drawing Number | Revision

5.6 Plant Performance data at full and part-load

Table 20 and Table 21 show the overall performance summary for full load and part load operations respectively.

Table 20 Scenario 4 (35% wt MEA soln.) overall performance summary at full load operation

Parameter	Unit	Value
Gross Power Output	MW	850.6
Gas Turbines Gross Power Output	MW	575.3
Steam Turbine Gross Power Output	MW	275.3
Power Island Losses and Auxiliary Power	MW	19.4
Carbon Capture Plant Auxiliary Power (inc. CO_2 comp.)	MW	45.7
CO_2 Compressor Power	MW	26.2
Overall Net Power Output	MW	785.5
Natural Gas Fuel Consumption (LHV)	MJ/s	1530.7
Natural Gas Fuel Consumption (HHV)	MJ/s	1694.4
Overall Net Efficiency (LHV)	%	51.32
Overall Net Efficiency (HHV)	%	46.36
Carbon Dioxide Captured	t/h	284
Carbon Dioxide Capture Efficiency	%	89.9
Stripper Reboiler Duty	MWth	248.3
Specific Heat Duty for CO_2 Captured	kJ/kg CO_2	3142.2
Stripper Condenser Duty	MWth	-54.0
Raw Water Consumption	t/h	994.8
Water Discharge Rate	t/h	384.4
Total CO_2 Captured	kg/MWh	362.1
Total CO_2 Emitted	kg/MWh	40.7

Table 21 Scenario 4 (35% wt MEA soln.) overall performance summary at part load (40% GT load) operation

Parameter	Unit	Value
Gross Power Output	MW	422.1
Gas Turbines Gross Power Output	MW	235.6
Steam Turbine Gross Power Output	MW	186.5
Power Island Losses and Auxiliary Power	MW	15.0
Carbon Capture Plant Auxiliary Power (inc. CO_2 comp.)	MW	25.8
CO_2 Compressor Power	MW	14.1*
Overall Net Power Output	MW	381.3
Natural Gas Fuel Consumption (LHV)	MJ/s	854.9
Natural Gas Fuel Consumption (HHV)	MJ/s	946.2
Overall Net Efficiency (LHV)	%	44.60
Overall Net Efficiency (HHV)	%	40.30
Carbon Dioxide Captured	t/h	158
Carbon Dioxide Capture Efficiency	%	89.9

Parameter	Unit	Value
Stripper Reboiler Duty	MWth	136.62
Specific Heat Duty for CO_2 Captured	kJ/kg CO_2	3106.9
Stripper Condenser Duty	MWth	-27.6
Raw Water Consumption	t/h	601.1
Water Discharge Rate	t/h	223.4
Total CO_2 Captured	kg/MWh	415.2
Total CO_2 Emitted	kg/MWh	46.5

** CO_2 compression auxiliary power at 40% load is based on operation of one compressor train at/near full-load to service two part-load CO_2 capture trains. The minimum turndown of CO_2 compressors is about 70% and lower loads would require recirculation of compressed CO_2. CO_2 compressor power at part load operation of both CO_2 compressor trains would correspond to an auxiliary power demand of around 18.3MW.*

5.7 Waste generated in the Power Plant and CCP processes

Main effluent streams from the Power Plant and CCP with their associated waste volumes are shown in Table 22 and Table 23.

Table 22 Waste generated by Power Plant (Scenario 4)

No.	Description	Unit	Value
1	Cooling water blow-down from ST condenser cooling tower	t/hr	69.14
2	Blow-down from HRSG drums	t/hr	1.9

Table 23 Waste generated by Capture and Compression Plant (Scenario 4)

No.	Description	Unit	Value
1	Cooling water blow-down from CCS plant cooling towers	t/hr	122.8
2	Amine waste	t/hr	0.9
3	Condensate waste from CO_2 compression	t/hr	5.4
4	Direct contact cooler condensed water	t/hr	182.3

6. OVERVIEW OF SCENARIO 5 (COMBINED CYCLE POWER PLANT WITH REFORMING PLANT AND PRE-COMBUSTION CAPTURE)

This section provides an overview of Scenario 5, which is a pre-combustion arrangement consisting of auto-thermal reforming process with water gas shift reactions and CO_2 separation by physical absorption using Selexol solvent. The section provides the rationale behind the selection of the reforming process, a process description, and details of the interfaces between the reforming plant and the CCGT. A utilities summary is provided, along with a layout for the plant and performance data at full and part load.

As yet, there are no commercial scale examples of this pre-combustion CO_2 capture technology being applied for the purposes of electricity generation. A number of studies have been carried out on the process which suggest it is feasible, and that it may present advantages over post-combustion capture, notably the potential to utilise CO_2 capture techniques which are less energy intensive. The process is also quite similar to commercially proven processes which produce hydrogen fuel by reforming natural gas – the main differences being the additional emphasis on the sequestration of CO_2 and the need to dilute the hydrogen fuel supplied to the CCGT. There are also several commercial applications of the physical absorption process with Selexol (especially for natural gas sweetening applications). These would however be at a scale smaller than the one considered for this Scenario. Parsons Brinckerhoff considers that all the equipment required for large CO_2 recovery plant have been commercially proven at smaller sizes and services, and that the increase in scale does not represent a huge technical challenge.

6.1 Reforming Technology Selection

Reforming involves the conversion of hydrocarbons present in natural gas, into mainly hydrogen and oxides of carbon. It is generally carried out through catalytic reaction with steam (steam reforming) or a mixture of steam and oxygen (for various adiabatic oxidative reforming processes).

6.1.1 Steam Reforming

Steam reforming is the preferred method for commercial manufacture of hydrogen. It involves the following *endothermic* reaction:

$$C_xH_y + xH_2O(g) \rightleftharpoons xCO + (x + \frac{y}{2})H_2 \quad -\Delta H^o_{298} < 0 \text{ kJ/mol} \qquad (6.1)$$

For methane, which is the main hydrocarbon present in natural gas, this reaction would be:

$$CH_4 + H_2O \rightleftharpoons CO + 3H_2 \quad -\Delta H^o_{298} = -206 \text{ kJ/mol} \qquad (6.2)$$

Large-scale steam reformers have a poor economy of scale compared with adiabatic oxidative reforming processes. Furthermore, a large heat input is required to support the endothermic process. This heat input would typically be supplied by external combustion.

6.1.2 Adiabatic Oxidative Reforming

In adiabatic oxidative reforming, the heat for the reforming process is supplied by internal combustion of a portion of the feed natural gas. The main advantages of this process over steam reforming are related to economies of scale (much larger stream units are possible) and to its more compact sizes of equipment. Higher conversions are also observed in these processes because of the higher outlet temperatures achievable with these units.

The main disadvantage of adiabatic oxidative reforming especially with O_2 as oxidant is that it requires an oxygen source which typically entails significant additional investments for air compression, or separation, or both.

Based on the scale of the application and the importance of overall plant efficiency, oxidative adiabatic reforming processes are preferred, and have been selected as the basis for this section of the study. These processes may be characterised by:

- The type of chemical reactions taking place:
    - Homogeneous reactions: (includes Partial Oxidation or POX);
    - Heterogeneous reactions (includes Catalytic Partial oxidation or CPO); or
    - Combination of homogeneous and heterogeneous (includes Auto-thermal Reforming (ATR) and Secondary reforming).
- The type of feed:
    - Feed from desulphurisation unit or prereformer: (POX, CPO and ATR); or
    - Partly reformed feed in a fired tubular reformer (secondary reforming)
- Type of oxidant:
    - Oxygen;
    - Oxygen-enriched air; or
    - Air

A number of commercial-scale ATR plants are in operation. These typically use oxygen as an oxidant, however some which use air as an oxidant have been used for the production of synthesis gas used in the production of ammonia.

6.1.2.1 Auto-thermal reforming with air as an oxidant for power production

Using air as the oxidant for syngas production for power generation has a number of advantages. Such a process would not require the additional capital and operating costs associated with a large Air Separation Unit (ASU) necessary to produce oxygen. Another key advantage is that nitrogen in the air is carried through the ATR process and then subsequently acts as a diluent for the hydrogen fuel gas produced (which is required to limit flame temperatures and NOx generation).

For these reasons, the reforming technology selected for this application was auto-thermal reforming with air as an oxidant.

6.2 Process Description

The process was developed to maximise interfaces between the CCGT and reforming plant in order to ensure the overall plant was as fuel efficient as possible (while maintaining reasonable plant operability).

The pre-combustion CO_2 capture plant consists of an integrated facility of a number of processes. The main sections of the facility include the desulphurisation unit, the reforming unit, the water gas shift reactors and the physical absorption CO_2 capture unit. There are a number of supporting unit operations which are included to improve overall plant efficiency, including a furnace pre-heater, absorber solvent chiller, and significant heat recovery exchangers

The process flow sheet was developed in consultation with Haldor Topsøe, who have undertaken previous work to investigate the *Integrated Reforming Combined Cycle* power concept. A simplified block flow diagram for the CO_2 capture process is presented in Section 6.4, and a full process flow diagram for the capture and compression plant is presented in Appendix A-4.

A separate reforming stream is proposed for each GT, to enhance overall plant availability.

6.2.1 Natural gas pre-conditioning and desulphurisation

Natural gas is pre-conditioned prior to feed to the reforming process, through a series of heat exchangers for waste heat recovery, and a pressure reducing station. The gas is then passed through the *furnace pre-heater*, to raise the temperature prior to the desulphurisation step.

The furnace pre-heater serves to improve the thermal efficiency of the reforming process. It is a five-element fired heater, with a common combustion air system and a common stack. The elements are used to pre-heat separate streams to appropriate temperatures for use in the process, including natural gas and process air to the reformer. The furnace pre-heater fires a mixture of the hydrogen / nitrogen fuel which is produced by the process (around 6t/hr), and some natural gas (around 4t/hr), in order to limit temperatures in the combustion zone. The furnace pre-heater is lined internally with refractory lining, and has a radiant and convective section.

Preheating the feed gas to the ATR by utilising the GT exhaust gas (using a dual function HRSG/Waste Heat Recovery Unit) was considered as an efficiency enhancer for the reforming process. However, considerations of the implications of such an integration resulted in this option not being utilised for the following reasons. Firstly, the nature of the HRSG would change with it combining air/water/steam heat exchange with air/pressurised flammable gas heat exchange. This would result in different safety and design standards being applicable to its design and fabrication, resulting in substantially increased costs and reduced numbers of manufacturers willing to tender for its supply. Secondly, the control and operation of the CCGT portion plant would change from its well known and well developed procedures (especially during start-ups), resulting in more teething problems during commissioning and higher risks for the assets within the CCGT plant, incurring greater insurance premiums. In addition, a greater degree of flaring during start-ups and upset conditions is likely to result.

Following pre-heating of the natural gas, the first step required in the process is desulphurisation of the natural gas, which constitutes one of the main feedstock purification requirements for the reforming process. This is because certain catalysts in the synthesis gas preparation section require very low concentration of sulphur compounds (preferably single digit ppb levels) to ensure acceptable lifetime.

Typically, a two-step process based on hydrogenation of organic sulphur compounds and subsequent adsorption of the resultant hydrogen sulphide is carried out. The feedstock is mixed with a small amount of hydrogen preheated to about 340°C (by a series of heat exchangers and the furnace pre-heater) and passed through the first reactor containing hydrogenation catalysts. Afterwards, the gas passes through a sulphur adsorber typically containing zinc oxide which adsorbs the hydrogen sulphide formed in the hydrogenator.

It is acknowledged that the feed gas used for this study (see Section 1.7.2) contains no sulphur compounds, and therefore arguably this process step could be omitted for the purposes of the modelling exercise. However in reality it is critical to include the desulphurisation unit since sulphur concentrations must be reduced to single digit ppb values to avoid poisoning downstream catalysts. Parsons Brinckerhoff have included this unit since it is considered unrealistic that such a plant would be constructed without some form of desulphurisation, and the relative contribution of capital costs is minimal.

6.2.2 Pre-reforming

The treated gas from the desulphurisation unit is mixed with intermediate pressure process steam which is generated at about 46barg in a process steam generator utilising waste heat from the syngas exiting the ATR. The gas / steam mixture is then heated up to 550°C by the furnace pre-heater (upstream the pre-reformer) which fires a combination of natural gas and hydrogen, before passing through the pre-reformer.

Adiabatic pre-reforming is a well established process which converts higher hydrocarbons in the feedstock (natural gas) into a mixture of carbon oxides and hydrogen (some unconverted methane and steam are also present in the pre-reformer product). The pre-reforming process avoids the danger of carbon formation on the catalyst surface, in the main section of the ATR.

6.2.3 Auto-thermal reforming

The process air required for auto-thermal reforming is derived from the gas turbine air compressor. A booster compressor raises the air pressure further to above 43barg for delivery to the ATR. This air stream is preheated to 540°C using a furnace pre-heater, and provides the oxygen needed to combust the process gas in the combustion zone of the ATR. The process gas from the pre-reformer is fed directly to the ATR. The steam to carbon mole ratio to the reformer is about 1.7.

In the combustion zone of the ATR, the following irreversible reaction is observed:

$$CH_4 + 1.5O_2 \rightarrow CO + 3H_2 \qquad -\Delta H^o_{298} = 519 \text{ kJ/mol} \qquad (6.3)$$

Oxygen is the limiting reactant and would therefore be fully consumed in this zone.

In the thermal and catalytic zone, the reforming and water gas shift reactions take place as shown in Figure 8.

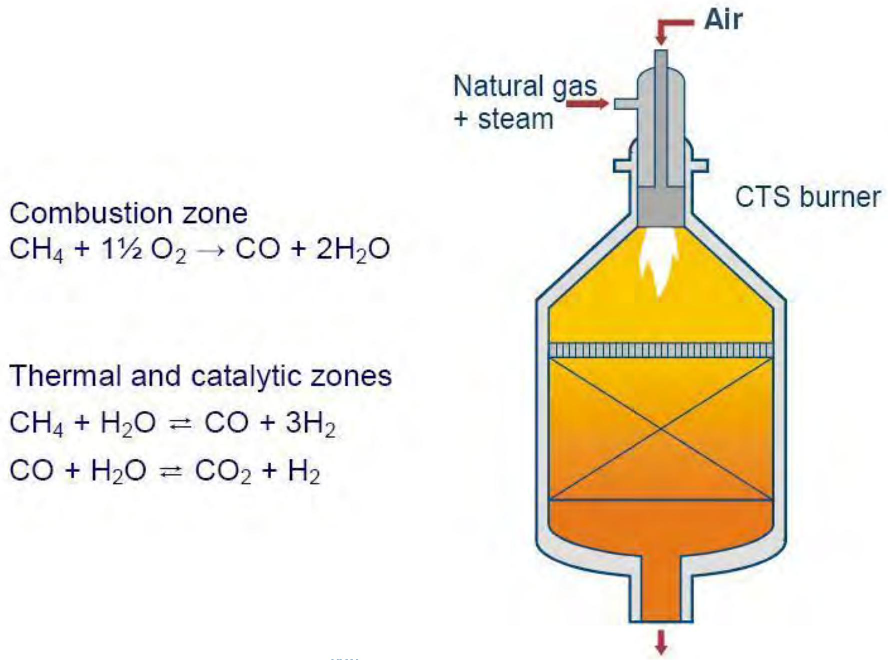


Figure 8 Auto-thermal reformer schematic[12]

The outlet pressure of the synthesis gas was set at about 40barg (about the upper limit of typical ATR operation) to achieve two main purposes:

- To avoid the need to recompress the hydrogen fuel gas sent to the gas turbine.
- To provide the highest possible partial pressure of CO_2 for the CO_2 separation process.

Based on these two requirements, the optimal pressure at the outlet of the ATR was selected as 40barg.

The drawback of operating at such pressures is the reduction in equilibrium conversion of methane – it was observed to drop to about 94% compared with the typical >99% conversion. This may not reduce the efficiency of the process (since methane would still be combusted in the gas turbine). However, it does result in increased overall CO_2 emissions due to an increase in methane leakage in the synthesis gas, which is subsequently combusted in the gas turbine.

The synthesis gas from the reformer contains about 29mol% H_2 and about 9mol% CO.

6.2.4 Water gas shift reactions

A two-stage water gas shift reaction process is utilized. The synthesis gas is cooled to about 350°C in a waste heat process steam generator and then passes through the high temperature shift reactor. The water gas shift reaction is as follows:

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \quad -\Delta H^{0}_{298} = 41 \text{ kJ/mol} \qquad (6.4)$$

This results in the production of more hydrogen and a reduction of carbon monoxide concentration to about 2.5mol%. The resultant gas stream is cooled to about 230°C and passed through the low temperature shift reactor where the carbon monoxide composition is reduced further to about 0.5mol%.

6.2.5 Physical absorption of CO_2 with Selexol

The product from the shift reactor is cooled as it exchanges heat in a waste heat boiler used to produce low pressure steam. It is passed through a water knockout drum from which the gas stream exits with a concentration about 16mol% CO_2. This stream is then mixed with recycle gas from the first flash drum and fed to the absorber column. In the absorber, chilled lean Selexol solvent (about -10°C) is contacted with the gas stream. Solvent circulation rates required for absorption are kept low by using such low solvent temperatures. The gas feed stream is supplied at about 37barg. A structured Mellapak 250Y packing is used to minimize pressure drops across the column. About 93.5% of the CO_2 in the absorber feed is captured by the solvent producing a fuel stream of about 44%mol nitrogen and 52%mol hydrogen.

Rich solvent regeneration and CO_2 recovery is carried out by a series of flash operations at cascading pressures. The absorption of hydrogen and methane is minimized by flashing the rich solvent at 8barg and 2°C, compressing the flashed gas and recycling it to the absorber column. The remaining solvent is sent to the second stage flash drum operated at 0.49barg and -4°C. The flashed vapour contains about 96mol% CO_2. The solvent is then passed through a heat exchanger where it exchanges heat with the lean (fully regenerated) solvent before it is finally heated up with low pressure steam to about 8.5°C. This semi-lean solvent is then sent to the last flash drum where it is flashed at -0.4barg yielding a CO_2 stream of about 99% purity. This stream is then compressed back to 0.49barg and mixed with the flashed gas from the second stage flash drum. The mixture (about 97mol% CO_2) is sent to the CO_2 compression and dehydration unit.

The regenerated solvent is recirculated via an absorption chiller which chills the solvent to -10°C before being returned to the absorber column.

6.2.6 CO_2 compression and dehydration

CO_2 from the physical absorption process is compressed to a pressure of 109barg by means of a five-stage compressor. The compression includes inter-stage cooling and knockout drums to remove and collect condensed water. The inter-stage cooling medium is circulating cooling water, itself cooled by a common cooling tower for the capture plant. The CO_2 is dehydrated in a tri-ethylene glycol (TEG) unit located before the final stage of compression, to remove water to a suitably low level in order to reduce corrosion in the CO_2 transportation system (less than 500ppm).

6.3 Interfaces with the CCGT

6.3.1 H_2/N_2 fuel supply, and conditioning

The hydrogen fuel gas for the gas turbine is supplied at a molar ratio of about 55:45 (H_2:N_2). The required concentration of N_2 is achieved by varying the amount of process air sent to the ATR. The presence of nitrogen in the fuel mix helps to limit the generation of nitrous oxide emissions (NOx) in the gas turbine.

Prior to delivery to the CCGT power block, the fuel gas is heated to 78°C as an efficiency measure, using waste heat in the form of low pressure steam generated through the syngas cooling process. Prior to combustion in the GT, the fuel gas is further heated to 230^{o}C using MP economiser water.

A de-rating of the standard GT inlet temperature that has been modelled may be required in practice for H_2 firing due to the greater heat transfer to the blades, and this would result in a slight reduction in efficiency of the overall plant; however, the development of components for high hydrogen combustion may minimise such an effect. It is noted that the major GT OEM's are working on performance improvement of gas-turbine technology when firing high-hydrogen content fuels and GE in particular note a focus on *"combustion, turbine, and materials technologies...for development, based on systems analysis that translated expected component improvements to the plant level.*"

GE also state that NO_x emission tests for high hydrogen combustion have been carried out "in excess of F-Class conditions", indicating the intent of their component developments.

Typically when firing hydrogen in a gas turbine, the turbine nozzle area must be increased from that of the reference plant, to accommodate the increased volumetric flowrate of fuel which is required (due to the lower heat content relative to natural gas) and to maintain the design pressure ratios of the machine. However, since the configuration of Scenario 5 is such that the GT compressor is sized to also supply compressed air for use in the reforming process, the increase in volumetric flow of fuel into the GT is offset by the equal amount of additional air extracted for the process. The overall pressure ratio of the GT is therefore similar to that of the reference plant without need for nozzle modifications.

Part of the fuel (about 1 tonne/hr) is mixed with the natural gas feed for desulphurisation. Some of the fuel (about 6 tonne/hr) is also used in the furnace pre-heater used in the process to heat up certain streams. The rest of the fuel is sent to the gas turbine.

6.3.2 Process and Heat integration

Process air for the reforming process is extracted from the gas turbine compressor. This is supplied at about 400°C and is used to superheat the process steam, the steam export to the power plant and produce low pressure steam for heat exchange.

The waste heat IP (intermediate pressure) steam generator is a major element of the reforming process heat recovery system. IP steam at a pressure of about 49barg is produced by heat recovery from the synthesis gas produced in the ATR. This steam is mainly used as process steam in the ATR, but the excess steam is exported to the CCGT to produce additional electricity. This steam export has resulted in a larger STG and condenser than would otherwise be required. Some excess steam is also used for heat exchange within the reforming process.

The boiler feed water supplied to the heat recovery system is obtained from the CCGT (a larger boiler feed water system has been allowed for). In addition, cooling water is derived from a common cooling water system.

In general, every reasonable effort has been made to maximise use of the waste heat which is generated by the process and to thereby optimise the net efficiency of the overall plant.

6.4 Block Flow Diagram

A simplified block flow diagram for the process is presented in Figure 9 and a full process flow diagram for the capture and compression plant is presented in Appendix A-4:

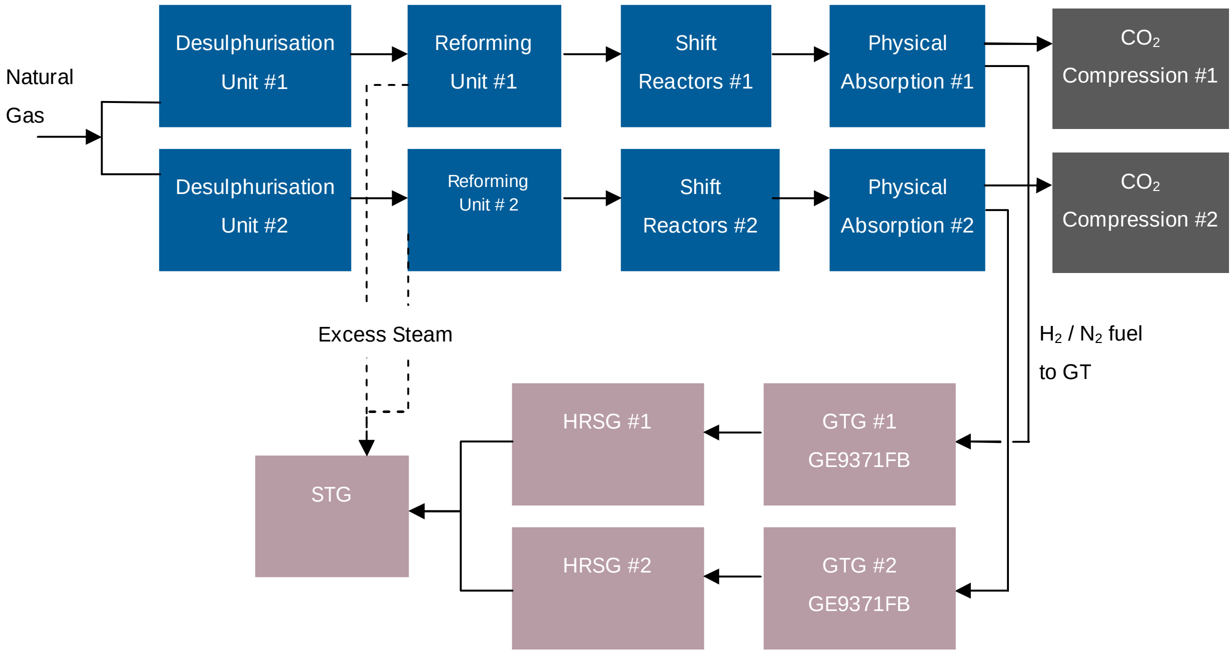


Figure 9 Scenario 5 Block Flow Diagram

6.5 Utilities Summary

The utility requirements for Scenario 5 are as follows;

Table 24 Utility Consumption of Scenario 5

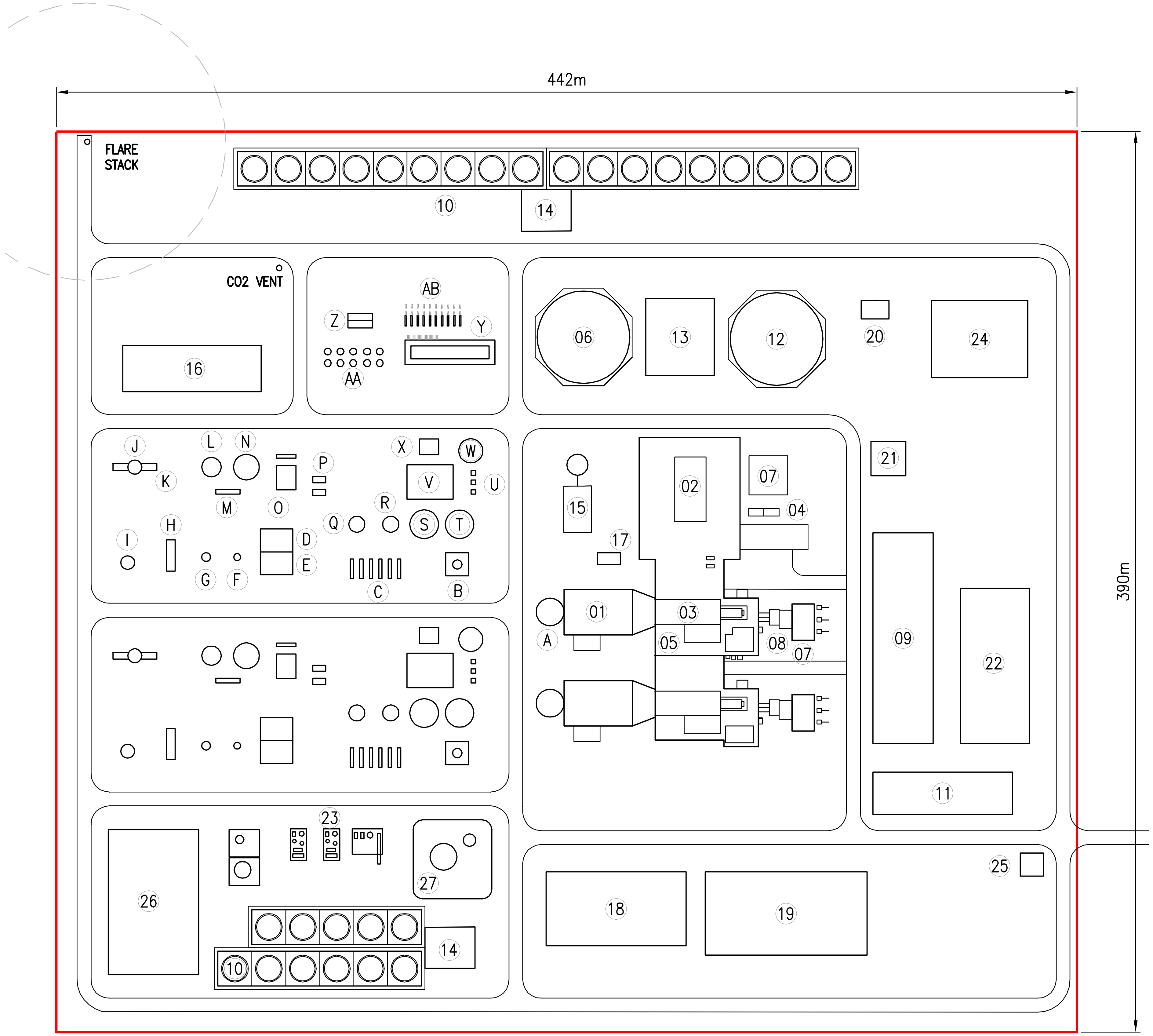
Utility	Unit	CCGT	Reforming / Capture	CO_2 Compression	Total
Electrical Power	MWe	26.0	69.7	39.6	135.3
Cooling Duty	MW	570.5	389.8	*Included in Ref / Cap.*	960.3
Cooling water	t/hr	44,390	23,772	4,400	72,562
Raw water	t/hr	696.4	857.2	*Included in Ref / Cap.*	1553.6*
Demin. water	t/hr	2.6	321	N/A	323.6

** Condensate recovered from knock-out drum D-003, is recycled for demin water make-up. Actual raw water requirement is therefore 1324.8t/hr.*

6.6 Layout Drawing

A layout drawing for Scenario 5 is shown on the following page. The drawing provides an indication of the reforming plant layout relative to the full power plant site to show interfaces between the power generation equipment and the reforming plant.

Layouts are intended primarily to provide an indication of plant footprint and possible interfaces. Details are expected to vary depending on the equipment provider, site location and further detailed design development.



LEGEND

01	HEAT RECOVERY STEAM GENERATOR	A	STACK
02	STEAM TURBINE AREA	B	FURNACE PRE-HEATER
03	GAS TURBINE AREA	C	NATURAL GAS/PROCESS AIR/PROCESS STEAM PRE HEATERS
04	CO2 LOW PRESSURE STATION	D	H_2/N_2 COMPRESSOR
05	GAS TURBINE INLET FILTER	E	PROCESS AIR BOOSTER COMPRESSOR
06	DEMINERALISED WATER STORAGE TANK	F	HYDROGENATOR
07	MAIN TRANSFORMER	G	DESULPHURISER
08	AUXILIARY TRANSFORMER	H	WASTE HEAT RECOVERY (LP STEAM)
09	GI SWITCHYARD	I	PRE-REFORMER
10	COOLING TOWERS	J	AUTOTHERMAL REFORMER
11	ADMINISTRATION	K	WASTE HEAT RECOVERY (IP STEAM)
12	RAW WATER/ FIREWATER STORAGE TANK	L	HT SHIFT REACTOR
13	WATER TREATMENT BUILDING	M	SYNGAS COOLER 2
14	CW PUMPHOUSE	N	LT SHIFT REACTOR
15	AUXILIARY BOILER	O	WASTE HEAT RECOVERY (LP STEAM)
16	GAS CONDITIONING FACILITY	P	SYNGAS COOLERS
17	EMERGENCY DIESEL GENERATORS	Q	KNOCK OUT DRUM
18	CONTROL BUILDING	R	CO_2 ABSORBER
19	WORKSHOP/STORAGE	S	FLASH DRUM 1
20	FIRE FIGHTING PUMP HOUSE	T	FLASH DRUM 2
21	FIRE STATION	U	SOLVENT H/EX
22	CAR PARK/LAYDOWN	V	ABSORPTION CHILLER
23	CONDENSATE POLISHING	W	FLASH DRUM 3
24	RAW-WATER PRE-TREATMENT	X	CO2 COMPRESSOR (BOOSTER)
25	GATE HOUSE	Y	CO2 COMPRESSOR HOUSE
26	EFFLUENT TREATMENT PLANT	Z	TEG DEHYDRATION PACKAGE
27	SELEXOL STORAGE AREA	AA	KNOCKOUT DRUMS
		AB	INTER-STAGE DISCHARGE COOLER

0 20m 40m 60m 80m 100m

BAR SCALE 1:2000

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6.7 Plant Performance data at full and part-load

Table 25 and Table 26 show the overall performance summary for full load and part load operations respectively.

Table 25 Scenario 5 overall performance summary at full load operation

Parameter	Unit	Value
Gross Power Output	MW	985.4
Gas Turbines Gross Power Output	MW	587.7
Steam Turbine Gross Power Output	MW	397.7
Power Island Losses and Auxiliary Power	MW	26.0
Reforming and CCP Auxiliary Power (inc. CO_2 comp.)	MW	109.5
CO_2 Compressor Power	MW	39.6
Overall Net Power Output	MW	849.9
Natural Gas Fuel Consumption (LHV)	MJ/s	2009.2
Natural Gas Fuel Consumption (HHV)	MJ/s	2224.0
Overall Net Efficiency (LHV)	%	42.30
Overall Net Efficiency (HHV)	%	38.22
Carbon Dioxide Captured	t/h	336.0
Carbon Dioxide Capture Efficiency	%	81.6*
Raw Water Consumption	t/h	1324.6
Water Discharge Rate	t/h	273.8
Total CO_2 Captured	kg/MWh	395.3
Total CO_2 Emitted	kg/MWh	89.4

** See Section 8.3*

Table 26 Scenario 5 overall performance summary at part load (40% GT load) operation

Parameter	Unit	Value
Gross Power Output	MW	520.6
Gas Turbines Gross Power Output	MW	262.7
Steam Turbine Gross Power Output	MW	257.9
Power Island Losses and Auxiliary Power	MW	21.0
Reforming and CCP Auxiliary Power (inc. CO_2 comp.)	MW	75.4
CO_2 Compressor Power	MW	23.9*
Overall Net Power Output	MW	424.2
Natural Gas Fuel Consumption (LHV)	MJ/s	1175.9
Natural Gas Fuel Consumption (HHV)	MJ/s	1301.6
Overall Net Efficiency (LHV)	%	36.1
Overall Net Efficiency (HHV)	%	32.6
Carbon Dioxide Captured	t/h	198.2
Carbon Dioxide Capture Efficiency	%	82.2
Raw Water Consumption	t/h	785.5
Water Discharge Rate	t/h	163.6
Total CO_2 Captured	kg/MWh	467.3

Parameter	Unit	Value
Total CO_2 Emitted	kg/MWh	101.2

** CO_2 compression auxiliary power at 40% load is based on operation of one compressor train at/near full-load to service two part-load CO_2 capture trains. The minimum turndown of CO_2 compressors is about 70% and lower loads would require recirculation of compressed CO_2. CO_2 compressor power at part load operation of both CO_2 compressor trains would correspond to an auxiliary power demand of around 27.7MW.*

6.8 Waste generated in the Power Plant and Reforming / CCP processes

Main effluent streams from the Power Plant and Reforming / CCP with their associated waste volumes are shown in Table 27 and Table 28.

Table 27 Waste generated by Power Plant (Scenario 5)

No.	Description	Unit	Value
1	Cooling water blow-down from ST condenser cooling tower	t/hr	138.6
2	Blow-down from HRSG drums	t/hr	2.6

Table 28 Waste generated by Reforming, Capture and Compression Plant (Scenario 5)

No.	Description	Unit	Value
1	Cooling water blow-down from Reforming plant cooling towers	t/hr	88.0
2	Selexol waste	t/yr	71.86
3	Condensate waste from CO_2 compression	t/hr	0.3

7. OVERVIEW OF SCENARIO 6 (REFORMING PLANT WITH PRE-COMBUSTION CAPTURE, PROVIDING H_2/N_2 TO A REMOTE COMBINED CYCLE POWER PLANT & INTERMEDIATE STORAGE)

This section provides an overview of Scenario 6, which is a pre-combustion arrangement consisting of auto-thermal reforming process with water gas shift reactions and CO_2 separation by physical absorption using Selexol solvent.

The key feature of Scenario 6 is that that the power plant is located remote from the reforming plant, and that a storage facility is also included, to allow intermediate storage of the H_2/N_2 fuel when the power plant is not operating (for example during outages).

The section provides the rationale behind the selection of the reforming process, a process description, and details of the interfaces between the reforming plant, the CCGT, and the storage site. A utilities summary is provided, along with a layout for the plant and performance data at full and part load.

7.1 Process Description

For the purposes of the study, it is assumed that the reforming plant is located 50km from the storage site, which is in turn located 5km from the combined cycle power plant. H_2 / N_2 is transported between the sites, via pipeline operating around 30 to 40barg (i.e. around the operating pressure of the reforming plant, and GT fuel pressure requirements). The distances between the plants have been selected arbitrarily but are considered as a reasonable basis for the study.

Much of the process for Scenario 6 is similar to that of Scenario 5, however there are several differences which are imposed by virtue of the fact that no integration is possible between the power plant and the reforming plant.

7.1.1 Natural gas desulphurisation

As per Scenario 5, the natural gas is pre-conditioned prior to feed to the reforming process, through a series of heat exchangers for waste heat recovery, and a pressure reducing station. The gas is then passed through the furnace pre-heater, to raise the temperature to 341^{o}C prior to the desulphurisation process.

The process conditions at the inlet to the two-step desulphurisation process are identical to that of Scenario 5. The Hydrogenator and Desulphurisation units proposed for each scenario are identical.

7.1.2 Pre-reforming

As per Scenario 5, the treated gas from the desulphurisation unit is mixed with process steam (at 47barg, and 298^{o}C). This steam is generated in a process steam generator utilising waste heat from the syngas exiting by the ATR. The steam is then superheated in a further heat recovery step, using waste heat from the air compression plant.

The gas / steam mixture is further heated to around 550^{o}C by the furnace pre-heater before entering the pre-reformer, where higher hydrocarbon compounds are converted to methane, CO, CO_2, and hydrogen.

7.1.3 Auto-thermal reforming

In Scenario 6, process air is supplied to the auto-thermal reformer via stand-alone air compression plant. Around 343t/hr of ambient air is compressed to 46barg (the operating pressure of the ATR). At the outlet of the compression plant, the air is around 347^{o}C and is then further heated by the furnace pre-heater to 540^{o}C. The five stage air compressor has a total combined power requirement of 73MW per train, and represents a significant additional auxiliary load on the process.

The ATR operates at the same pressure as that of Scenario 5, and syngas exhausts the ATR at around 40barg before passing to the process steam generator and water gas shift reactors.

7.1.4 Water gas shift reactors

The two-stage water gas shift process is identical to that of Scenario 5. See Section 6.2.4.

7.1.5 Physical absorption of CO_2 with Selexol

The physical absorption process is identical to that of Scenario 5. See Section 6.2.5.

7.1.6 CO_2 compression and dehydration

The CO_2 compression process is identical to that of Scenario 6. See Section 6.2.6.

7.2 Interfaces with the CCGT and Hydrogen / Nitrogen Storage site

7.2.1 GT modifications

As stated in Section 6.3.1, when firing hydrogen in a gas turbine, the turbine nozzle area must be increased to accommodate the increased volumetric flowrate of fuel which is required and to maintain the design pressure ratios of the machine. In Scenario 6 (in which process air extraction from the GT for the reforming process is not possible), the turbine nozzle area is increased by 6% compared to that of the reference case, such that design pressure ratios are maintained. The turbine nozzle area would be increased as per GE's standard method by replacing the Stage 1 nozzle with a nozzle having a larger flow area to accommodate the increased mass flow that occurs with syngas operation.

7.2.2 H_2/N_2 fuel storage site

For the purposes of the study, it is assumed that the H_2/N_2 storage site is a worked-over salt cavern (notionally located in the Zechstein salt deposits in NE Netherlands) at a depth of between 4000ft (1220m) and 6200ft (1890m). It is assumed that the cavern has a working capacity of 24bscf (644M Nm^3), equivalent to approximately six weeks of H_2 / N_2 production from the reforming plant when continually operating at base load, which is considered a sensible time period to allow for major overhaul of the power plant. It is assumed that the storage cavern operates at around 36.1barg, utilising around 20bscf (537M Nm^3)of base gas to maintain pressure.

The H_2 / N_2 fuel is compressed at the reforming plant, to a pressure of 62barg, and the then transported by pipeline to the storage facility (for the purposes of the study, assumed to be 50km away). A dedicated 10 MW compressor, and dedicated 36" pipeline is proposed for each reforming plant train.

Costs include for work-over / leaching of the salt cavern, H_2/N_2 handling facilities (compressors and other top-sides equipment), storage wells, and pipelines, are more fully detailed in Section 9.3.5.1.

7.2.3 Process and Heat integration

In general, every reasonable effort has been made to maximise use of the waste heat which is generated by the process and to thereby optimise the net efficiency of the overall plant. The key distinction between the process heat integration solution for Scenario 6 and Scenario 5 is that the excess steam generated by the ATR process is exported to a stand-alone STG (common for both trains), located on the reforming plant site (as opposed to supplementing the main power plant STG).

The IP Steam is generated by the Syngas Cooler at the outlet of the ATR, at 50barg and 265^{o}C, and at a rate of 339.0t/hr. Around 40%wt of this steam is superheated to 300^{o}C utilising waste heat from the air compression plant, and used as process steam. The remainder of the saturated steam is sent to the stand-alone steam turbine generator. The steam turbine generator has a gross power output of 49.8MW, which is used to offset some of the auxiliary power requirements of the process.

7.2.3.1 Process integration

Other implications of a remote power plant are that several of the balance of plant & utility systems which are shared between the power plant and reforming plant in Scenario 5, must exist separately for Scenario 6. As such, Scenario 6 requires that the reforming plant and power plant each have dedicated demineralised water treatment plants, waste water treatment plants, raw and demineralised water storage facilities, gas reception facilities, and buildings. These additional items all contribute to a greater CAPEX requirement for Scenario 6 (more fully detailed in Section 9.3.5).

7.3 Block Flow Diagram

A simplified block flow diagram for the process is presented in Figure 10 and a full process flow diagram for the reforming plant, capture plant, and air compression plant is presented in Appendix A-5.

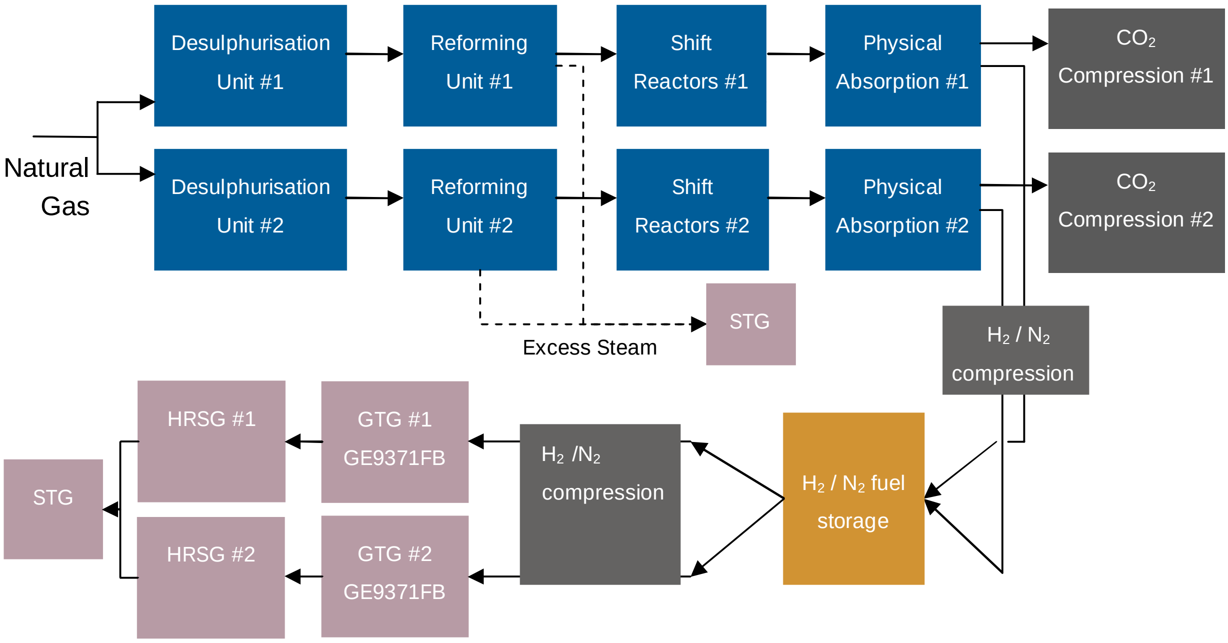


Figure 10 Scenario 6 Block Flow Diagram

7.4 Utilities Summary

The utility requirements for Scenario 6 are as follows;

Table 29 Utility Consumption of Scenario 6

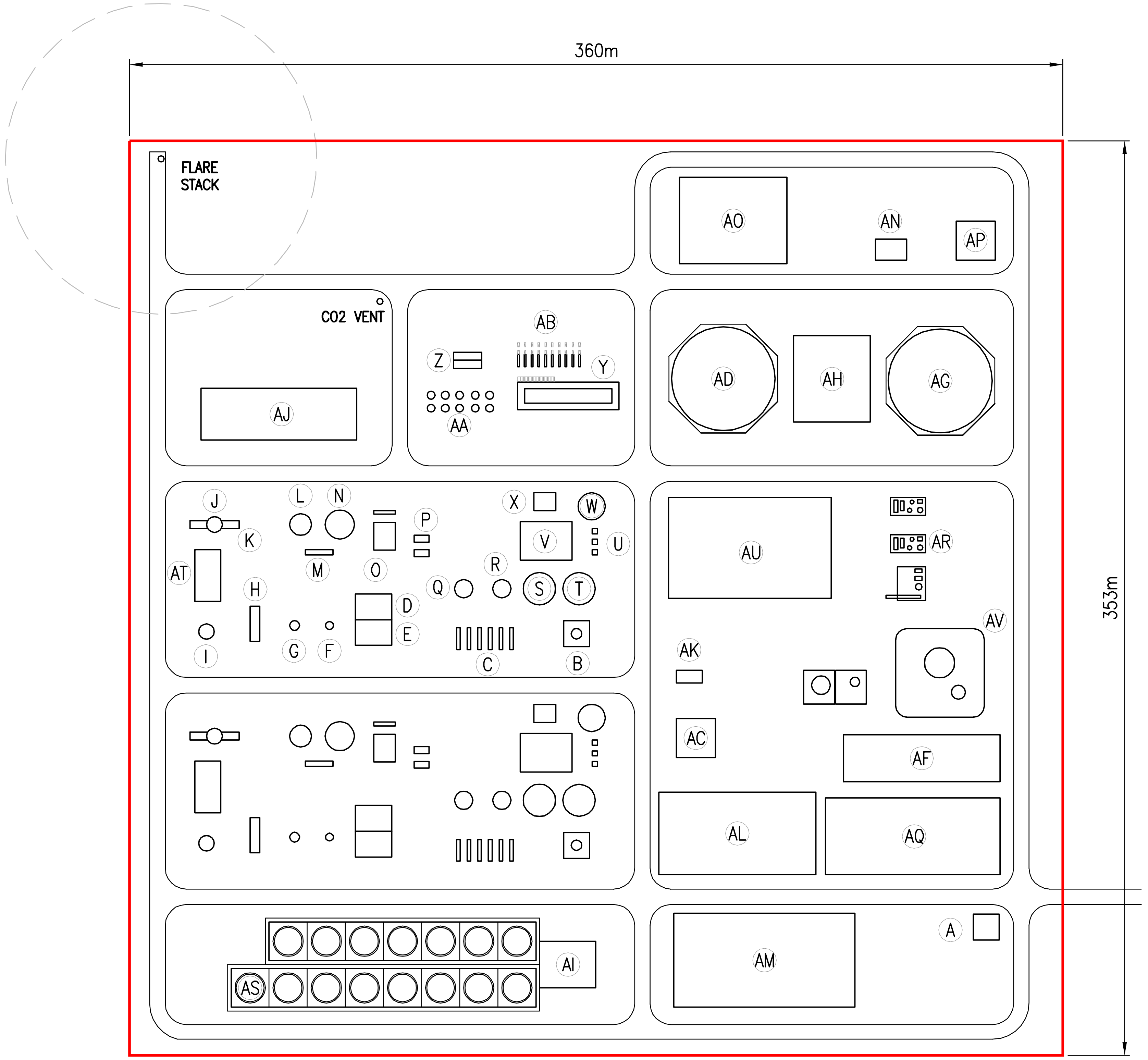
Utility	Unit	CCGT	Reforming / Capture	CO_2 Compression	Total
Electrical Power	MWe	38.2	198.8	39.4	276.4
Cooling Duty	MW	452.1	558.7	*Included in Ref / Cap.*	1010.9
Cooling water	t/hr	35,157	36,791	4,400	76,348
Raw water	t/hr	552.9	1023.2	*Included in Ref / Cap.*	1576.1*
Demin. water	t/hr	2.7	292	N/A	294.7

** Condensate recovered from knock-out drum D-003, is recycled for demin water make-up. Actual raw water requirement is therefore 1347.3t/hr.*

7.5 Layout Drawing

Layout drawings for Scenario 6 are shown on the following pages. Separate drawings are provided for the reforming plant, and power plant.

Layouts are intended primarily to provide an indication of plant footprint and possible interfaces. Details are expected to vary depending on the equipment provider, site location and further detailed design development.



LEGEND

AA	KNOCKOUT DRUMS	A	GATE HOUSE
AB	INTER–STAGE DISCHARGE COOLER	B	FURNACE PRE–HEATER
AC	STEAM TURBINE AREA	C	NATURAL GAS/PROCESS AIR/PROCESS STEAM PRE HEATERS
AD	DEMINERALIZED WATER STORAGE TANK	D	H_2/N_2 COMPRESSOR
AE	AUXILIARY TRANSFORMER	E	PROCESS AIR BOOSTER COMPRESSOR
AF	ADMINISTRATION	F	HYDROGENATOR
AG	RAW WATER/ FIREWATER STORAGE TANK	G	DESULPHURISER
AH	WATER TREATMENT BUILDING	H	WASTE HEAT RECOVERY (LP STEAM)
AI	CW PUMPHOUSE	I	PRE–REFORMER
AJ	GAS CONDITIONING FACILITY	J	AUTOTHERMAL REFORMER
AK	EMERGENCY DIESEL GENERATORS	K	WASTE HEAT RECOVERY (IP STEAM)
AL	CONTROL BUILDING	L	HT SHIFT REACTOR
AM	WORKSHOP/STORAGE	M	SYNGAS COOLER 2
AN	FIRE FIGHTING PUMP HOUSE	N	LT SHIFT REACTOR
AO	RAW–WATER PRE–TREATMENT	O	WASTE HEAT RECOVERY (LP STEAM)
AP	FIRE STATION	P	SYNGAS COOLERS
AQ	CAR PARK/LAYDOWN	Q	KNOCK OUT DRUM
AR	CONDENSATE POLISHING	R	CO_2 ABSORBER
AS	COOLING TOWERS	S	FLASH DRUM 1
AT	PROCESS AIR COMPRESSOR	T	FLASH DRUM 2
AU	EFFLUENT TREATMENT PLANT	U	SOLVENT H/EX
AV	SELEXOL STORAGE AREA	V	ABSORPTION CHILLER
		W	FLASH DRUM 3
		X	CO2 COMPRESSOR (BOOSTER)
		Y	CO2 COMPRESSOR HOUSE
		Z	TEG DEHYDRATION PACKAGE

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SHEET 1 OF 2

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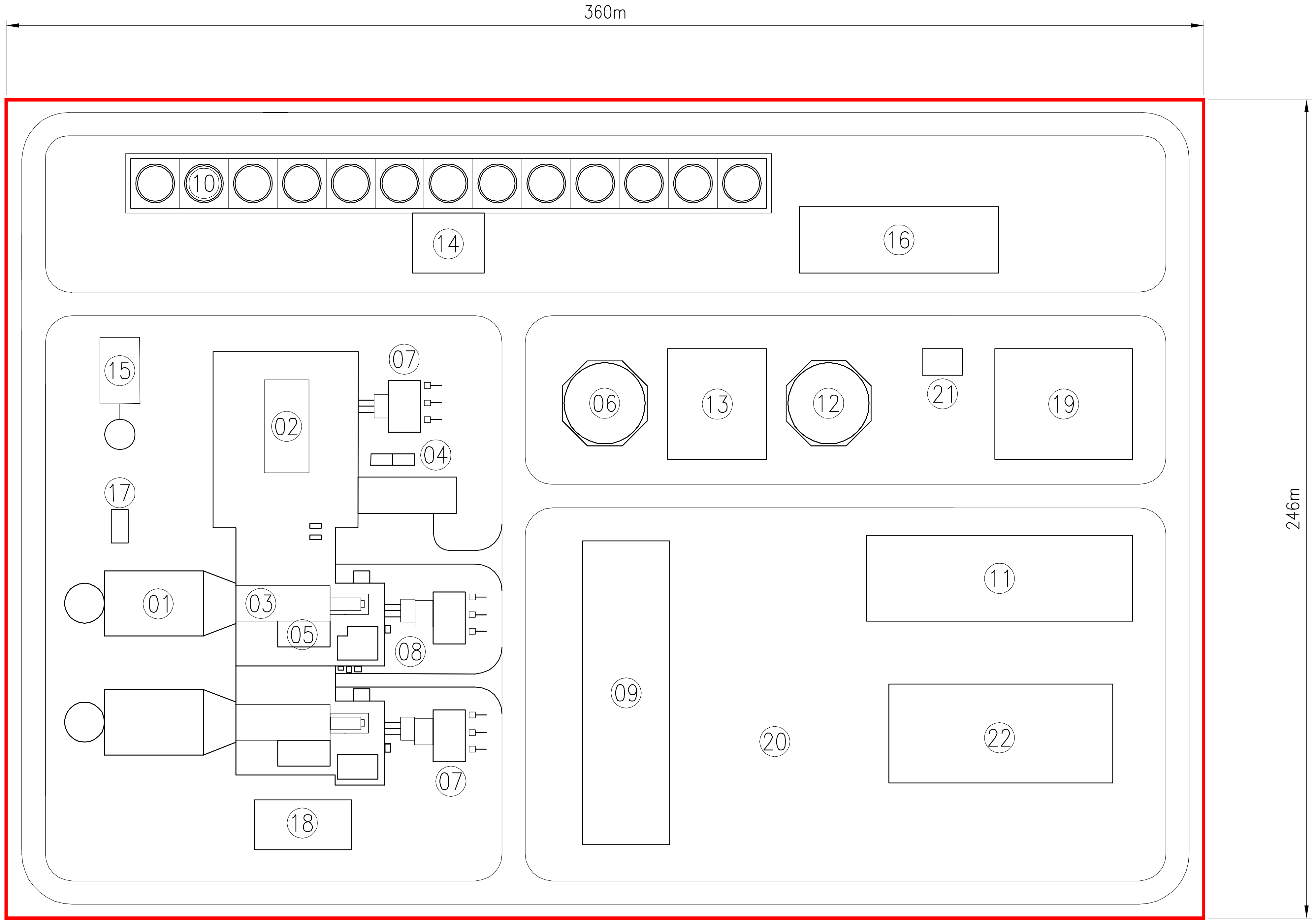
Project Number: 64225A	Drawing Number: -DSC-00014	Revision:	



LEGEND

- 01 HEAT RECOVERY STEAM GENERATOR
- 02 STEAM TURBINE AREA
- 03 GAS TURBINE AREA
- 04 CO2 LOW PRESSURE STATION
- 05 GAS TURBINE INLET FILTER
- 06 DEMINERALIZED WATER STORAGE TANK
- 07 MAIN TRANSFORMER
- 08 AUXILIARY TRANSFORMER
- 09 GI SWITCHYARD
- 10 COOLING TOWERS
- 11 WAREHOUSE/MAINT./ADMIN
- 12 RAW WATER/ FIREWATER STORAGE TANK
- 13 WATER TREATMENT BUILDING
- 14 CW PUMPHOUSE
- 15 AUXILIARY BOILER
- 16 GAS CONDITIONING FACILITY
- 17 EMERGENCY DIESEL GENERATORS
- 18 CONTROL BUILDING
- 19 RAW-WATER PRE-TREATMENT
- 20 POSSIBLE LAYDOWN/OPEN STORAGE AREA
- 21 FIRE FIGHTING PUMPHOUSE
- 22 CAR PARKING

0 25m 50m 75m 100m

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SHEET 2 OF 2

Drawn: B.B. | Checked: IA
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7.6 Plant Performance data at full and part-load

Table 30 and Table 31 show the overall performance summary for full load and part load operations respectively.

Table 30 Scenario 6 overall performance summary at full load operation

Parameter	Unit	Value
Gross Power Output (inc. CCGT and reform. plant STG)	MW	1013.2
Gas Turbines Gross Power Output	MW	640.1
Steam Turbine Gross Power Output	MW	323.3
Reformer Plant STG Gross Power Output	MW	49.8
Power Island Losses and Auxiliary Power	MW	38.2
Reforming and CCP Auxiliary Power (inc. CO_2 comp.)	MW	238.1
CO_2 Compressor Power	MW	39.4
Overall Net Power Output	MW	736.8
Natural Gas Fuel Consumption (LHV)	MJ/s	2004.8
Natural Gas Fuel Consumption (HHV)	MJ/s	2219.2
Overall Net Efficiency (LHV)	%	36.75
Overall Net Efficiency (HHV)	%	33.20
Carbon Dioxide Captured	t/h	334.8
Carbon Dioxide Capture Efficiency	%	81.4*
Raw Water Consumption	t/h	1347.3
Water Discharge Rate	t/h	277.3
Total CO_2 Captured	kg/MWh	454.4
Total CO_2 Emitted	kg/MWh	103.6

** See Section 8.3*

Table 31 Scenario 6 overall performance summary at part load (40% GT load) operation

Parameter	Unit	Value
Gross Power Output (inc. CCGT and reform. plant STG)	MW	557.7
Gas Turbines Gross Power Output	MW	297.5
Steam Turbine Gross Power Output	MW	230.9
Reformer Plant STG Gross Power Output	MW	29.3
Power Island Losses and Auxiliary Power	MW	28.2
Reforming and CCP Auxiliary Power (inc. CO_2 comp.)	MW	140.3
CO_2 Compressor Power	MW	16.5
Overall Net Power Output	MW	389.3
Natural Gas Fuel Consumption (LHV)	MJ/s	1180.8
Natural Gas Fuel Consumption (HHV)	MJ/s	1307.1
Overall Net Efficiency (LHV)	%	33.0
Overall Net Efficiency (HHV)	%	29.8
Carbon Dioxide Captured	t/h	197.2
Carbon Dioxide Capture Efficiency	%	81.4
Raw Water Consumption	t/h	765.5

Parameter	Unit	Value
Water Discharge Rate	t/h	158.0
Total CO_2 Captured	kg/MWh	506.6
Total CO_2 Emitted	kg/MWh	115.5

** CO_2 compression auxiliary power at 40% load is based on operation of one compressor train at/near full-load to service two part-load CO_2 capture trains. The minimum turndown of CO_2 compressors is about 70% and lower loads would require recirculation of compressed CO_2. CO_2 compressor power at part load operation of both CO_2 compressor trains would correspond to an auxiliary power demand of around 27.6MW.*

7.7 Waste generated in the Power Plant and CCP processes

Main effluent streams from the Power Plant and CCP with their associated waste volumes are shown in Table 32 and Table 33.

Table 32 Waste generated by Power Plant (Scenario 6)

No.	Description	Unit	Value
1	Cooling water blow-down from ST condenser cooling tower	t/hr	109.9
2	Blow-down from HRSG drums	t/hr	2.7

Table 33 Waste generated by Reforming, Capture and Compression Plant (Scenario 6)

No.	Description	Unit	Value
1	Cooling water blow-down from Reforming plant & STG cooling towers	t/hr	128.7
2	Selexol waste	t/yr	71.9
3	Condensate waste from CO_2 compression	t/hr	0.3

8. COMPARISON OF PERFORMANCE DATA, AND EVALUATION

This section provides a comparison of the key performance parameters for each scenario, and includes some commentary and analysis on the results.

8.1 Overall Plant Performance comparison

The main performance parameters for each scenario are presented in Table 34. In summary;

1. A Combined cycle power plant (Reference Plant);
2. Scenario 2 not used;
3. A Combined cycle power plant with post-combustion capture using 35%wt MEA solvent;

3b. A Combined cycle power plant with a typical proprietary post-combustion capture system;

4. A Combined cycle power plant with post-combustion capture using 35%wt MEA solvent and flue-gas recirculation;
5. A Combined cycle power plant with Natural Gas reforming and pre-combustion capture;
6. A Natural Gas Reforming plant with pre-combustion capture, providing hydrogen to a remote combined cycle power plant or intermediate storage; and
7. Scenario 7 not used

Table 34 Overall Results Comparison

Scenario	Gross Power Output (MW)	Net Power Output (MW)	Net Efficiency (%)	CO_2 Cap. Rate (t/hr)	CCGT Aux. Load (MW)	CO_2 Capture & Comp Block Aux. Load (MW)
Scenario 1	934.04	910.29	58.87	-	23.74	-
Scenario 3	860.12	789.33	51.04	288.0	19.38	51.41
Scenario 3b	874.20	803.95	51.98	289.0	20.18	50.07
Scenario 4	850.61	785.53	51.32	284.0	19.37	45.71
Scenario 5	985.40	849.94	42.30	336.0	25.97	109.50
Scenario 6	1013.17	736.81	36.75	334.8	38.24	238.12

All figures are for 100% base load operation, Efficiency is on LHV basis

8.2 Gross Power Output, Net Power Output & Net Efficiency comparison

Data for power output and net efficiency at 100% load, is presented in Figure 11.

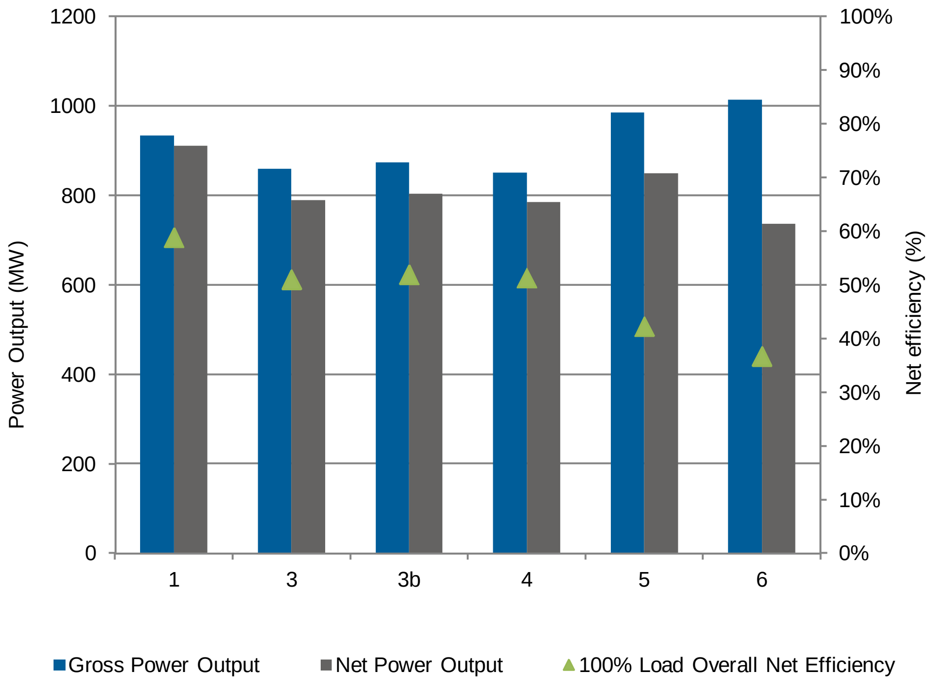

Figure 11 Gross / Net Power Out & Net Efficiency comparison at 100% Load

As can be seen from Table 34 and Figure 11, the net power output of the scenarios varies between 736 – 910 MW. Configurations of the power block and capture plant were selected as far as possible to achieve an overall power output around 800 MW, although it can be seen that the auxiliary loads imposed by each capture technology differ by as much as 190MW, which has resulted in some variance in final power outputs. Auxiliary loads of the power plant also differ from scenario to scenario. Auxiliary loads are compared in Figure 12.

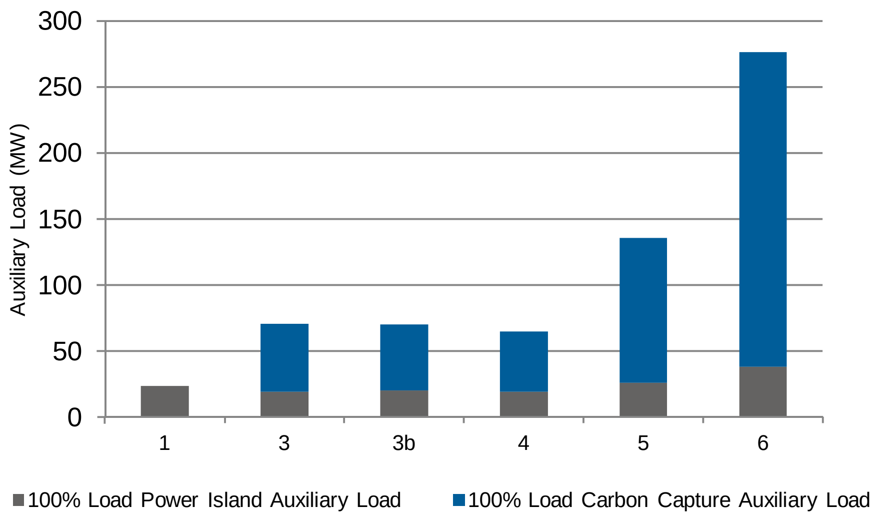

Figure 12 Auxiliary Loads comparison at 100% load

For the power plant, auxiliary losses are typically around 25MW, which includes for transformer losses, and power associated with boiler feed pumps, cooling tower pumps and draft fans etc. For Scenario 6, the power island auxiliary losses also include for H_2/N_2 fuel compression from the storage site, to ensure the fuel is supplied at the correct pressure at the inlet to the gas turbines.

Of greater significance to overall power output are the auxiliary loads associated with carbon capture and compression. For post combustion capture, the main auxiliary loads are those of the electrical drives of the flue-gas fans, the CO_2 compressor, and the additional cooling tower pumps and draft fans. The other main contributor to a reduction in power output is extraction of LP steam from the turbine cross-over, for use in the stripper column. This steam extraction (which would otherwise be expanded through the LP section of the STG to generate electrical power), results in an additional decrease to overall power output. In comparison to the reference plant, the overall reduction in power output for post combustion carbon capture is around 121MW for Scenario 3 (35%wt MEA solvent), which corresponds to an efficiency drop of around 8% points. When using a proprietary solvent system, it is estimated that the overall reduction in power output is around 106MW, which corresponds to a 7% point efficiency drop. For Scenario 4, the theoretical modelling suggests a slight improvement in overall efficiency over Scenario 3, with a 7.5% point drop compared to the reference plant (corresponding to a reduction in net power output of 124.76MW). In principle, the results suggest that an optimal post-combustion capture solution would utilise a proprietary solvent in conjunction with flue-gas recirculation, however it is noted that this has not been considered within the scope of this study.

For pre-combustion capture, the auxiliary losses are considered to include all plant and equipment included in the Reforming Block, and the CO_2 Capture and Compression blocks. As can be seen, the auxiliary losses for Scenario 5 and 6 are considerably greater than those for the post-combustion scenarios, principally due to the additional requirement in these scenarios for air compression required to supply the process air to the ATR.

In Scenario 5, the process air is extracted from the GT compressor, which is sized to provide both the combustion air and ATR process air (a booster compressor K-002 is used to provide additional compression to the process air prior to feed to the ATR). Given that Scenario 5 is intended to be an integrated natural gas reforming and power plant, the decision was taken to interface air compression systems in this way, resulting in a significant capital saving with respect to air compression for Scenario 5. This is albeit offset by reductions in GT efficiency, and an operational constraint which necessitates start-up of the CCGT on natural gas to enable start-up of the reforming plant.

For Scenario 6 in which the CCGT is remote from the reforming plant, a stand-alone air compressor for each stream must be used to provide all the process air. While this means that the plants can operate independently, it does incur a significant capital cost (approximately EUR42M), and an auxiliary load of 145MW (72.5MW per train). In conjunction with this, Scenario 6 also requires compression plant to transfer H_2/N_2 fuel from the reforming plant to the storage site, *and* subsequently to the CCGT, which entails an additional auxiliary load of 36.2MW (18.1MW per train). A dedicated cooling tower is also required for the stand-alone STG, which imposes additional auxiliary power losses. In total, the auxiliary load for carbon capture is around 165MW greater for Scenario 6 when compared to Scenario 5. Table 35 provides an approximate indication of the major auxiliary losses associated with Scenario 5 and Scenario 6.

Table 35 Comparison of auxiliary loads for Scenario 5 and 6

	Scenario 5		Scenario 6	
	CCGT Aux. Load	Reforming Plant, CO_2 Capture & Comp Block Aux. Load	CCGT Aux. Load	Reforming Plant, CO_2 Capture & Comp Block Aux. Load
Transformer losses	19%		12%	
HRSG feed-pumps	24%		19%	
Cooling water pumps	19%		9%	
Cooling Tower fans	12%		6%	
H_2/N_2 GT fuel compressors			27%*	9%**
Process air compressor		39%		61%
CO_2 Absorber Recycle compressor		4%		2%
Flash drum 3 CO_2 booster compressor		2%		1%
Lean solvent pump		11%		5%
CO_2 compressor		36%		17%
Cooling tower fans and pumps		5%		3%
Other	26%	3%	14%	2%
	100%	100%	100%	100%
Total	**25.97MW**	**109.5MW**	**38.24MW**	**238.12MW**

** Compression from reforming plant to storage*

*** Compression from storage to CCGT*

The net efficiency of Scenario 6 is 36.8%, which is 22.0% points less than that of the reference plant, and 5.5% points less than that of Scenario 5. It can be concluded that *Scenario 6 does not represent an efficient use of natural gas for power production*. There are several contributing factors to this:

- The conversion efficiency of the reforming process is around 85%, introducing energy losses in comparison to direct combustion of natural gas in the CCGT, and these losses can only be mitigated when the CCGT is co-located with the reforming plant;

- The reforming and pre-combustion capture plant is a complex process, and has greater numbers of rotating plant such as large compressors and pumps, all of which introduce additional auxiliary power losses; and
- The storage site is dedicated to one reforming plant and one CCGT, where in reality the auxiliary loads associated with fuel storage may be better offset against multiple producers / consumers.

It can be concluded that CO_2 capture of any nature (pre or post combustion) will result in additional auxiliary losses and a drop in efficiency from that of the reference case. Of the carbon capture options considered it can be concluded that Scenario 3b is the most efficient. The efficiency of Scenario 4 is marginally improved (0.5% points) over that of Scenario 3, through flue gas recirculation.

8.3 CO_2 Capture Rate & Capture Efficiency comparison

Results for CO_2 capture rate and capture efficiency for each scenario at 100% load and 40% GT load, are presented in Figure 13 for Scenarios 3 to 6:

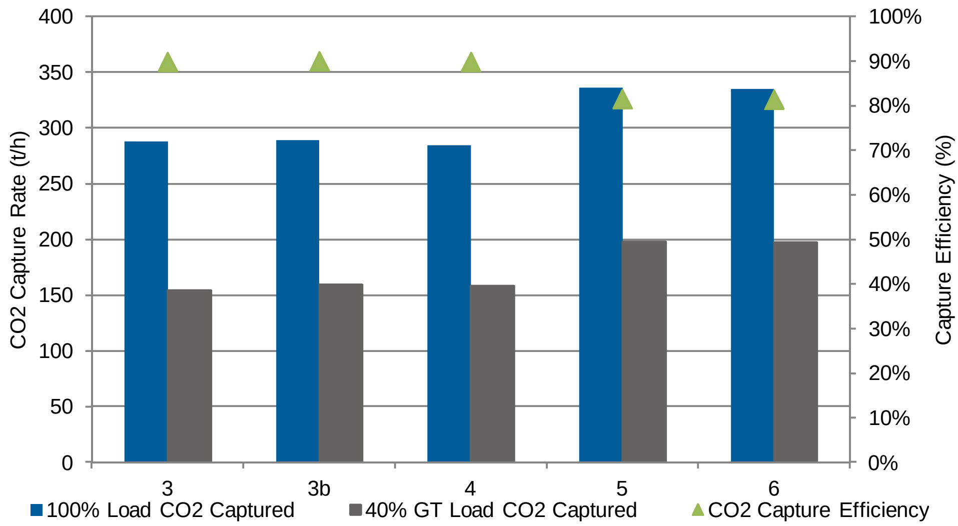

Figure 13 CO_2 Capture rates and efficiencies comparison at 100% and 40% GT load

As can be seen from Figure 13, CO_2 capture rates are highest for Scenario 5 and 6, at around 335 t/hr. Capture rates for Scenario 3, 3b and 4 are slightly lower, at 288 t/hr, 289 t/hr and 284 t/hr respectively. However, this is primarily due to a higher fuel consumption for Scenario 5 and 6 (around 2,000 $MJ/s_{LHV\ basis}$) than for Scenario 3, 3b and 4 (around 1,500 $MJ/s_{LHV\ basis}$). Capture efficiency is in fact higher for the post-combustion scenarios than for the pre-combustion scenarios, at around 90% for Scenario 3 and 4, and around 81.5% for Scenario 5 and 6.

The absorption efficiency for the post-combustion chemical absorption is 90%, and the pre-combustion physical absorption using Selexol is 93.5%. However, owing to combustion of a mixture of H_2 / N_2 and Natural Gas in the furnace pre-heaters (for pre-heating of the natural gas and process air streams to the reformer) and some minor methane *slippage* through the ATR to the CCGT (the fuel to the GT contains around 1%mol methane which is subsequently combusted) there results in release of some unabated CO_2 emissions, and an overall capture efficiency of 81% for the pre-combustion scenarios. Optimising the capture efficiency of any scenario requires a trade-off between many factors, including plant efficiency, fuel prices, CO_2 emission penalties, plant capital cost, construction / material limitations, and operating costs. Parsons Brinckerhoff believe that the capture efficiency presented for Scenario 5 and 6 represents an appropriate capture efficiency given the scope of this study, but would note that further improvements may be achievable with further design work.

8.4 Cooling duty comparison

The total cooling duties for each scenario at 100% load, and 40% GT load are presented in Figure 14 and Figure 15 respectively;

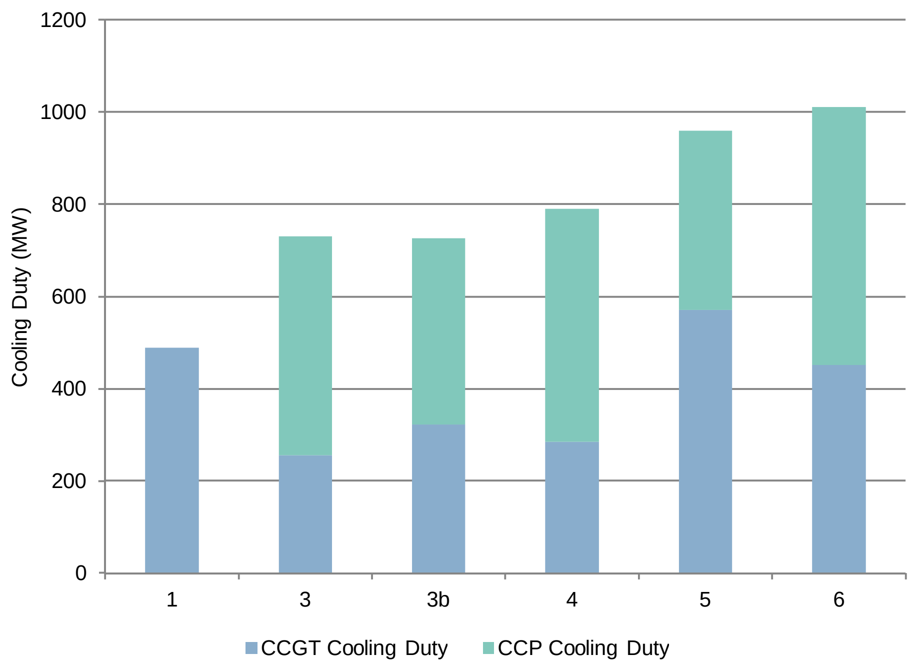

Figure 14 Cooling duty comparison at 100% load

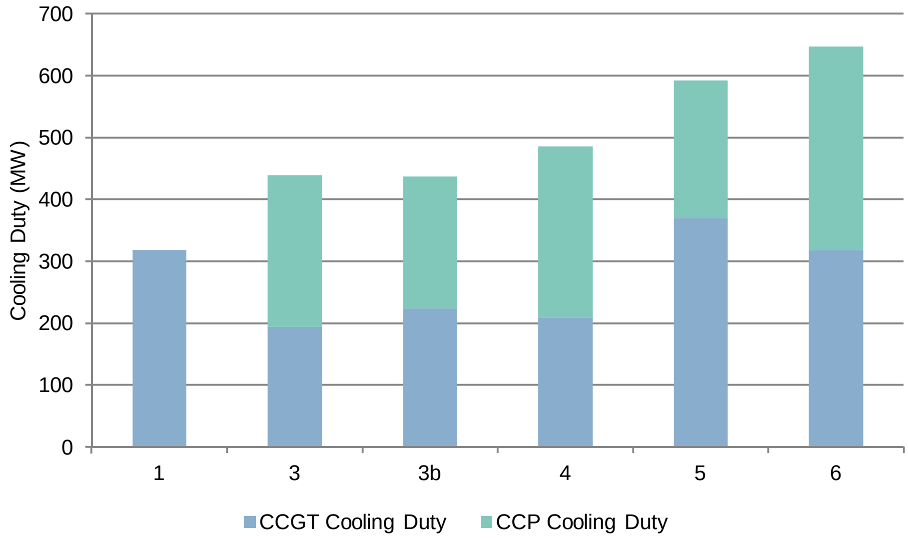

Figure 15 Cooling duty comparison at 40% GT load

The cooling duty required for the CCGT when operating at base load, without any form of carbon capture, is 489 MW_{th}. This is heat rejected to the condenser by steam exhausted from the LP turbine, and which is ultimately rejected to the cooling towers. At 40% load, less steam is generated by the HRSGs and the cooling duty requirement is 318 MW_{th}.

For Scenario 3 and 4, the overall cooling duty requirement also includes the cooling duty for the capture and compression plant. A significant contributor to this cooling requirement is heat rejected by the condensate returning from the stripper reboiler and flue gas re-heater. In effect, this cooling duty is transferred from the CCGT to the CO_2 Capture Block, since the reboiler uses steam extracted from the LP section of the turbine – steam which would otherwise exhaust to the condenser (albeit at lower enthalpy). The utilisation of waste heat in the reboiler condensate to reheat the flue gases prior to exhaust to atmosphere, lowers the cooling duty requirement and improves the thermal efficiency of the process.

In addition, the CO_2 Capture and Compression block cooling duty requirement includes heat rejected by flue gas cooled in the DCC, and excess heat rejected from the lean solvent as it returns to the absorber (the absorption process is exothermic). There is also an additional cooling duty associated with inter-stage cooling of the CO_2 compression plant.

For Scenario 5, the cooling duty for the CCGT is 570.5 MW, which is around 16% higher than that of Scenario 1. This is due to a higher plant output for Scenario 5, since excess steam generated by the reforming process is exported to the steam turbine resulting in a higher power output and condenser duty. In addition, the Scenario 5 CO_2 compression plant inter-stage cooling accounts for an further 29 MW_{th}.

8.5 Water Consumption and Discharge Rates

The water consumption and discharge rates for each scenario at 100% load are presented in Figure 16 and Figure 17 respectively;

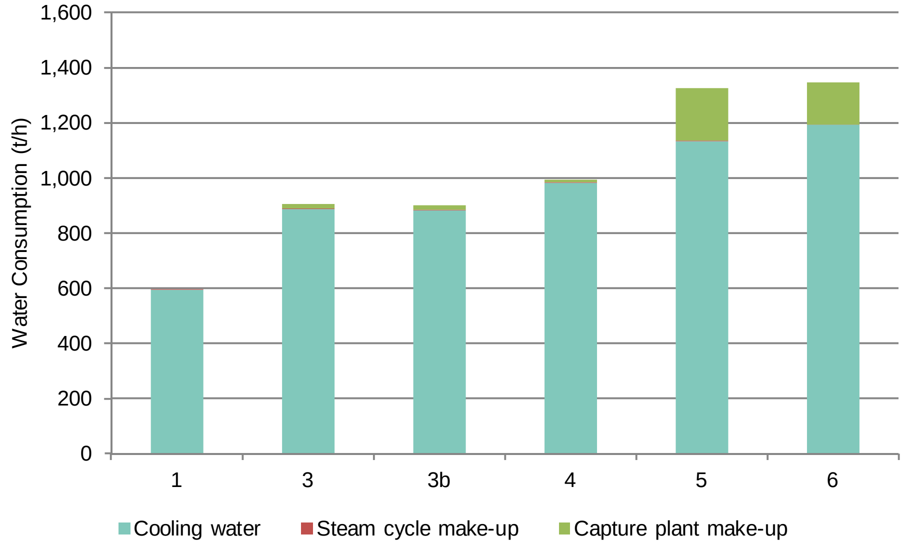

Figure 16 Water consumption comparison at 100% load

The majority of the total water consumption for each scenario is make-up cooling water for the power plant cooling towers and the capture plant cooling towers. For scenario 5 and 6, additional make-up water is consumed in the production of process steam which is subsequently used by the reforming process.

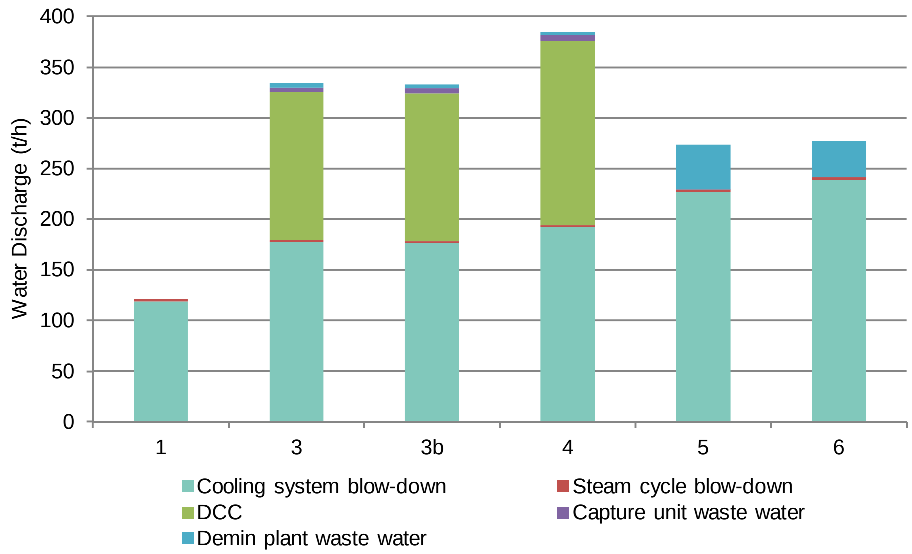

Figure 17 Water discharge comparison at 100% load

Cooling tower blow-down represents a significant proportion of all water discharge for each scenario. In the post-combustion scenarios, water condensed in the DCC is also discharged to waste (although it is noted that for CCGT systems the quality of this waste water is expected to be quite high and there is potential for recycle in other areas of the process).

9. CAPITAL AND OPERATING COSTS

9.1 Introduction

A capital and operating cost estimate has been developed for each scenario, for use as inputs to the economic evaluation which is further explained in Section 10. These cost estimations have been independently derived by Parsons Brinckerhoff, based on the functional designs presented in the previous sections and equipment sizes derived through performance modelling and consultation with OEM's and other technology providers.

It should be noted that capital costs are estimates only, and that lower EPC costs may be realised through a competitive tendering process.

The capital cost estimates have been based on several sources, including:

- Up to date vendor quotations for major equipment items;
- Reference project out-turn data for mature technologies (e.g. thermal plant and ancillary plant);
- PEACE (Plant Engineering and Cost Estimator) module for GT Pro; and
- Parsons Brinckerhoff in-house cost estimate data, based on extensive CCS project cost reviews / estimates undertaken between 2007-2011, on behalf of HM Government (DECC), Australian Federal and State Government, and the Global CCS Institute.

All estimates presented are current money values (2011 costs), with a 5% p.a. escalation applied to reference figures from previous years.

All costs are presented in Euros (EUR), and as far as possible, vendor quotations have also been sought in EUR. Foreign exchange rates have been assumed as follows:

- 0.75 EUR: 1 USD; and
- 1.14 EUR: 1 GBP.

All currencies are presented in ISO4217 format.

Total capital costs are presented for turn-key plant on a green-field site, delivered on an EPC contract basis, including a sum for contingency and profit for the EPC contractor.

Owners costs (inc. for example in-house feasibility engineering, land purchase, permitting costs, costs for project finance etc) are included separately for completeness.

The overall accuracy of the capital cost estimates is in the range ± 40%.

9.2 Cost Summary

Costs are presented in the format as shown in Table 36 and a full explanation of terms is presented on the following pages. Costs for each scenario are grouped according to general plant area, for example *Combined Cycle Power Plant*, *CO_2 Capture Block*, and *CO_2 Compression Block* etc. Cost breakdowns for each scenario are also presented graphically, showing the relative cost of each plant area.

Table 36 Cost Estimate Breakdown

	Description		Area1 EUR	Area2 EUR	Area3 EUR	Area4 EUR	Area5 EUR	Total
	DIRECT MATERIALS							
	Major Equipment							
	Piping							
	Electrical							
	Control and Instrumentation							
	Solvents, Catalysts & Other Bulk Chemicals							
	SUB-TOTAL DIRECT MATERIALS							
	MATERIAL / LABOUR CONTRACTS							
	CIVILS / STEELWORK / BUILDINGS							
	TANKS AND VESSELS							
	SUB-TOTAL MATERIAL & LABOUR CONTRACTS							
	LABOUR CONTRACTS							
	MECHANICAL							
	ELECTRICAL / INSTRUMENTATION							
	SCAFFOLDING / LAGGING / RIGGING							
	SUB-TOTAL LABOUR CONTRACTS							
	SUB-TOTAL LABOUR & MATERIALS							
	ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT							
	COMMISSIONING / START-UP							
	SOFT COSTS CONTRACTOR (Inc Contingency & Profit)							
	SOFT COSTS OWNER							
	SUB-TOTAL OTHER COSTS							
	TOTAL PROJECT COSTS							

9.2.1 Direct Materials

The ‘Direct Materials’ line item includes costs of all specialised plant equipment delivered to site, and is a sum of all major equipment costs for a given plant area. For example the Direct Materials costs for the CCGT power plant include equipment costs for the gas turbines (including all combustion systems, starter-systems, inlet air filtration systems and local ancillary plant), steam turbines, HRSGs, condenser, cooling towers, continuous emissions monitoring (CEM) systems, distributed control systems (DCS), and generating and transmission voltage equipment. Balance of plant items such as the waste water treatment plant, medium voltage (MV) and low voltage (LV) electrical systems, tanks, pumps, and turbine house cranes, are also included in the ‘Major Equipment’ costs.

For a post combustion capture plant, the Major Equipment costs include items such as the absorbers, strippers, and flue gas blowers etc and all other plant items identified on the process flow diagram and equipment lists.

Piping, Control & Instrumentation, and supporting electrical systems costs are included as separate line items within the ‘Direct Materials’ subset. For the Combined Cycle Plant, the piping costs are derived directly from GT Pro PEACE, comprising all pipe-work (but excluding supports and insulation/lagging which are included elsewhere). For other plant areas, these costs are estimated as a percentage of the Major Equipment costs.

9.2.2 Material and Labour Contracts

The ‘Material and Labour Contracts’ line item includes costs of all other major items that are delivered and constructed in-situ, and whose costs are a combination of material and labour. So for example, this includes civil work-scope contracts which comprise of civil materials such as cement, aggregate, reinforcing steel etc, and the labour required to construct. Also included in this line item are all plant buildings, and steelwork including racks, supports, and access ladders, platforms and walkways, for a given plant area.

9.2.3 Labour Only Contracts

The ‘Labour Only Contracts’ line item includes costs for all labour for construction of the given plant area. It is separated by workforce (‘Mechanical’, ‘Electrical and Instrumentation’ and ‘Scaffolding / Insulation / Rigging’). For the combined cycle power plant, these costs are derived from GT Pro PEACE. In all other instances, the labour costs are estimated as a percentage of the total ‘Direct Materials’ costs for a given plant area.

9.2.4 Other Costs

The ‘Other Costs’ line item includes engineering and management costs for the EPC delivery of the project, start-up costs, and soft costs for both the Contractor and the Owner.

'Engineering costs' include design undertaken by the Contractor, from Feasibility design, through FEED, and detailed construction design. This sum also includes for EPC project management and site management throughout the project.

'Commissioning / Start-up' costs include labour and management during commissioning, but excludes start-up spares which have not been included in this cost estimate. Fuel and consumables used during commissioning are included in the economic model, but are not presented here.

The 'Contractor's Soft Costs' includes contingency and profit (applied separately to labour and equipment costs), contractor company overheads, bonds and insurances. For the purposes of this study, contingency is applied at 25% to all labour, and around 5-10% on Direct Materials, though it is noted that perceived risks of fluctuations in materials costs (commodities such as steel and copper) will have a significant bearing on the contingency that a contractor will apply on any given project. For the purposes of the study, profit is applied at 25% to all labour, and around 7% on Direct Materials. It is noted that such costs are highly dependent on factors such as location, EPC / OEM market competition, and regional variations in labour and materials costs. As such the Contractors Soft Cost estimates included in this study should be viewed as estimates only, and it is recognised that such costs may be improved upon.

The 'Owner's Soft Costs' includes owner company overheads, project finance costs, insurances, development fees, legal fees, land-purchase / lease costs, in-house engineering costs, connection fees, and permitting and consenting costs.

9.2.5 Total Plant Costs and Total Capital Requirement Costs

The summation of all costs excluding the Owners Soft costs represents the *Total Plant Cost* (TPC), and can be considered to be representative of the EPC contract price to the Owner. It should be noted that an EPC contract for any given scenario which is competitively tendered may result in a TPC which is significantly lower than that presented in this report.

The summation of TPC and the Owners Soft Costs represents the *Total Capital Requirement Cost* (TCR). This can be considered to be representative of the full project cost.

The capital costs presented are reflective of overnight costs and therefore do not include interest during construction (IDC). IDC is taken into consideration in the economic model (See Section 10.3.2).

9.3 Capital cost summary for each scenario

9.3.1 Scenario 1

The capital cost summary for the CCGT reference plant is presented on the following page. The total capital requirement is **EUR632,125,361** which equates to around **EUR694/kW**. Less Owners Soft Costs, this is equivalent to EUR637/kW.

PARSONS BRINCKERHOFF

Project Number:64225A
Project Name:CO_2 Capture at Gas Fired Power Plants Study
Client: IEA Environmental Projects Ltd.

Scenario 1: Combined Cycle Power Plant

Date: 26-08-11
Revision: A

Description	Combined Cycle EUR	CO_2 Capture Block EUR	Reforming Block EUR	CO_2 Compression Block EUR	Common Facilities EUR	
DIRECT MATERIALS						
Major Equipment	305,705,115	0	0	0	0	
Piping	32,958,584	0	0	0	0	
Control and Instrumentiaton	-	0	0	0	0	
Electrical	2,961,428	0	0	0	0	
Solvents, Catalysts & Other Bulk Chemicals		0	0	0	0	
SUB-TOTAL DIRECT MATERIALS	341,625,127	0	0	0	0	
SHIPPING / FREIGHT	-	0	0	0	0	
THIRD PARTY INSPECTION	-	0	0	0	0	
SPARE PARTS (Commissioning / 2 Years Operating)	-	0	0	0	0	
SPARE PARTS (Capital / Insurance)	-	0	0	0	0	
SUB-TOTAL MATERIALS	341,625,127	0	0	0	0	
MATERIAL AND LABOUR CONTRACTS						
TANKS AND VESSELS	Inc. above	0				
CIVILS / STEELWORK / BUILDINGS	64,973,253	0	0	0	0	
SUB-TOTAL MATERIAL & LABOUR CONTRACTS	64,973,253	0	0	0	0	
LABOUR ONLY CONTRACTS						
MECHANICAL	29,630,854	0	0	0	0	
ELECTRICAL / INSTRUMENTATION	9,353,213	0	0	0	0	
SCAFFOLDING / LAGGING / RIGGING	7,289,537.00	0	0	0	0	
SUB-TOTAL LABOUR ONLY CONTRACTS	46,273,604.00	0	0	0	0	
SUB-TOTAL LABOUR AND MATERIALS	452,871,984	0	0	0	0	
ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT	14,477,000	0	0	0	0	
COMMISSIONING	2,506,675	0	0	0	0	
SOFT COSTS CONTRACTOR (Inc Contingency & Profit)	110,075,865					
SOFT COSTS OWNER	52,193,837	0	0	0	0	
SUB-TOTAL OTHER COSTS	179,253,377	0	0	0	0	
TOTAL PROJECT COSTS	**632,125,361**	**0**	**0**	**0**	**0**	**632,125,361**

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9.3.2 Scenario 3 and Scenario 3b

The capital cost summary for Scenario 3 is presented on the following pages. The total capital requirement is **EUR1,209,782,669** which equates to around **EUR1,533/kW** (based on TCR). Less Owners Soft Costs, this is equivalent to EUR1,401/kW. A graphical representation of the breakdown of costs is shown in Figure 18.

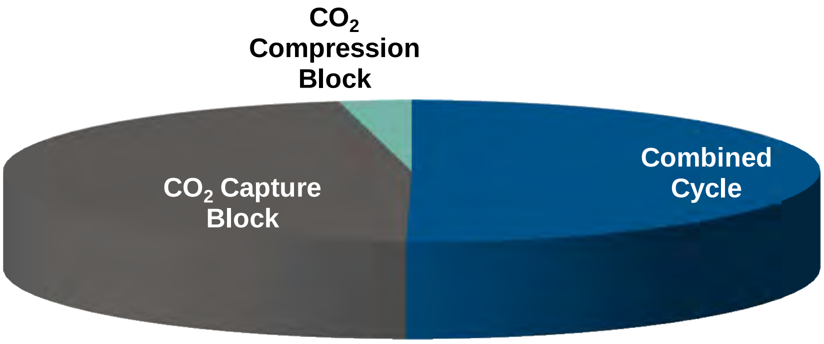

Figure 18 CAPEX breakdown for Scenario 3

Around 50% of the total capital requirement is attributable to the power plant, which equates to around EUR608M. The CO_2 Capture Block accounts for approximately 47%, with the CO_2 compression plant making up the balance (3%).

Of the EUR232M which is required for Major Equipment for the CO_2 Capture Block, approximately 35% is for the absorber columns and their ancillaries (one column per train), and around 33% for the stripper columns (one per train). A breakdown of the CO_2 Capture Block Major Equipment costs, by process area, is shown in Table 37;

Table 37 Scenario 3 CO_2 Capture Block cost breakdown

Process Area	Equipment items	Cost Estimate
Flue gas cooling	Ductwork, Flue gas fan, Direct Contact Cooler (inc. packing, distributor & collector), DCC Pump, and DCC heat exchanger.	EUR8,768,110 (per train)
CO_2 absorber & flue gas re-heater	CO_2 absorber (inc. packing and column internals), absorber water wash cooler, absorber water wash pumps, and flue gas re-heater.	EUR45,289,108 (per train)
Rich / lean amine circulation	Rich solvent pump, rich / lean exchanger, lean solvent pump, lean amine cooler, closed loop cooling system, lean solvent filtration system	EUR2,621,868 (per train)
Stripping Section	Stripper columns (inc. packing and column internals), re-	EUR57,517,108 (per

Process Area	Equipment items	Cost Estimate
	boilers, overheads condensers & receivers, reflux pumps, stripper water wash pumps.	train)
Ancillaries	Solvent Re-claimer, solvent storage (inc. loading and unloading), raw water system, demineralised water system, firewater water system, nitrogen and compressed air packages.	EUR3,850,672
	Total	**EUR232,243,060**

9.3.2.1 Scenario 3b

The capital costs of a proprietary CO_2 capture system are typically significantly lower than that of a conventional MEA system by virtue of improved solvent performance with respect to absorption capacity (resulting in a shorter absorber column and packing section), lower regeneration energy requirements (resulting in a shorter stripper column and smaller re-boilers) and less tendency to vapourise (resulting in smaller water wash systems).

Parsons Brinckerhoff's estimate of the total capital requirement is **EUR1,024,514,752** which equates to around **EUR1,274/kW** (based on TCR). Less Owners Soft Costs, this is equivalent to EUR1,165/kW. This represents a CAPEX improvement of approximately 17% over that of Scenario 3. Note that this cost estimate is not based on any particular proprietary system, and is only intended to provide a representative indication of the CAPEX savings which might be achieved.

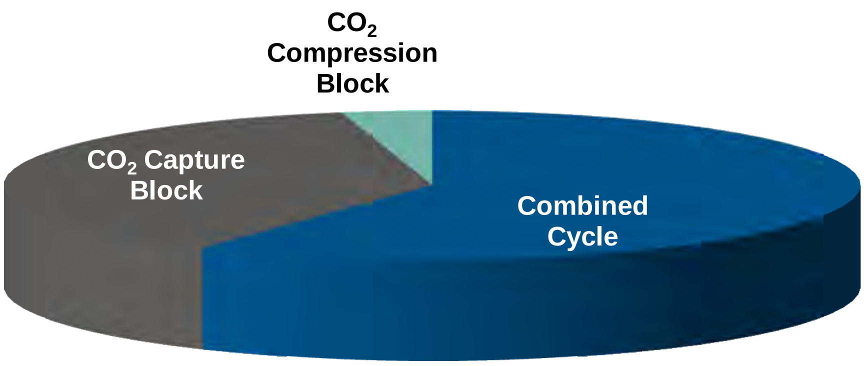

Figure 19 CAPEX breakdown for Scenario 3b

PARSONS BRINCKERHOFF

Project Number:64225A
Project Name:CO_2 Capture at Gas Fired Power Plants Study
Client: IEA Environmental Projects Ltd.

Scenario 3: Combined Cycle Power Plant with Post Combustion Capture

Date: 26-08-11
Revision: A

Description	Combined Cycle EUR	CO_2 Capture Block EUR	Reforming Block EUR	CO_2 Compression Block EUR	Common Facilities EUR	
DIRECT MATERIALS						
Major Equipment	279,591,066	232,243,060	0	16,512,490	0	
Piping	32,951,112	34,836,459	0	1,651,249	0	
Control and Instrumentation	-	4,644,861	0	330,250	0	
Electrical	2,635,631	9,289,722	0	412,812	0	
Solvents, Catalysts & Other Bulk Chemicals	-	1,665,660	0	-	0	
SUB-TOTAL DIRECT MATERIALS	315,177,809	282,679,763	0	18,906,801	0	
SHIPPING / FREIGHT	-	0	0	0	0	
THIRD PARTY INSPECTION	-	0	0	0	0	
SPARE PARTS (Commissioning / 2 Years Operating)	-	0	0	0	0	
SPARE PARTS (Capital / Insurance)	-	0	0	0	0	
SUB-TOTAL MATERIALS	315,177,809	282,679,763	0	18,906,801	0	
MATERIAL AND LABOUR CONTRACTS						
TANKS AND VESSELS	Inc. above	Inc. above		Inc. above		
CIVILS / STEELWORK / BUILDINGS	72,742,274	65,016,345	0	3,781,360	0	
SUB-TOTAL MATERIAL & LABOUR CONTRACTS	72,742,274	65,016,345	0	3,781,360	0	
LABOUR ONLY CONTRACTS						
MECHANICAL	26,838,810	25,441,179	0.00	1,701,612	0.00	
ELECTRICAL / INSTRUMENTATION	7,922,618	8,480,393	0.00	567,204	0.00	
SCAFFOLDING / LAGGING / RIGGING	6,724,875	7,066,994	0.00	472,670	0.00	
SUB-TOTAL LABOUR ONLY CONTRACTS	41,486,303	40,988,565.58	0.00	2,741,486	0.00	
SUB-TOTAL LABOUR AND MATERIALS	429,406,386	388,684,674	0	25,429,647	0	
ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT	13,372,000	10,600,491	0	652,285	0	
COMMISSIONING	2,506,675	2,332,108	0	265,000	0	
SOFT COSTS CONTRACTOR (Inc Contingency & Profit)	110,075,865	116,605,402		5,672,040		
SOFT COSTS OWNER	52,193,837	49,150,239	0	2,836,020	0	
SUB-TOTAL OTHER COSTS	178,148,377	178,688,240	0	9,425,345	0	
TOTAL PROJECT COSTS	**607,554,763**	**567,372,914**	**0**	**34,854,993**	**0**	**1,209,782,669**

Project Number:64225A Project Name:CO_2 Capture at Gas Fired Power Plants Study Client: IEA Environmental Projects Ltd.	Scenario 3b: Combined Cycle Power Plant with Post Combustion Capture (Proprietary Solvent)					Date: 07-3-12 Revision: B
Description	**Combined Cycle**	**CO_2 Capture Block**	**Reforming Block**	**CO_2 Compression Block**	**Common Facilities**	
	EUR	**EUR**	**EUR**	**EUR**	**EUR**	
DIRECT MATERIALS						
Major Equipment	280,289,714	157,349,745	0	16,512,490	0	
Piping	32,545,147	23,602,462	0	1,651,249	0	
Control and Instrumentation	-	3,146,995	0	330,250	0	
Electrical	2,572,133	6,293,990	0	412,812	0	
Solvents, Catalysts & Other Bulk Chemicals	-	1,665,660	0	-	0	
SUB-TOTAL DIRECT MATERIALS	315,406,994	192,058,851	0	18,906,801	0	
SHIPPING / FREIGHT	-	0	0	0	0	
THIRD PARTY INSPECTION	-	0	0	0	0	
SPARE PARTS (Commissioning / 2 Years Operating)	-	0	0	0	0	
SPARE PARTS (Capital / Insurance)	-	0	0	0	0	
SUB-TOTAL MATERIALS	315,406,994	192,058,851	0	18,906,801	0	
MATERIAL AND LABOUR CONTRACTS						
TANKS AND VESSELS	Inc. above	Inc. above		Inc. above		
CIVILS / STEELWORK / BUILDINGS	70,264,057	44,173,536	0	3,781,360	0	
SUB-TOTAL MATERIAL & LABOUR CONTRACTS	70,264,057	44,173,536	0	3,781,360	0	
LABOUR ONLY CONTRACTS						
MECHANICAL	26,154,377	17,285,297	0.00	1,701,612	0.00	
ELECTRICAL / INSTRUMENTATION	7,674,719	5,761,766	0.00	567,204	0.00	
SCAFFOLDING / LAGGING / RIGGING	6,568,812	4,801,471	0.00	472,670	0.00	
SUB-TOTAL LABOUR ONLY CONTRACTS	40,397,908	27,848,533.46	0.00	2,741,486	0.00	
SUB-TOTAL LABOUR AND MATERIALS	426,068,959	264,080,921	0	25,429,647	0	
ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT	13,443,000	7,202,207	0	652,285	0	
COMMISSIONING	2,506,675	1,584,486	0	265,000	0	
SOFT COSTS CONTRACTOR (Inc Contingency & Profit)	110,075,865	79,224,276		5,672,040		
SOFT COSTS OWNER	52,193,837	33,279,534	0	2,836,020	0	
SUB-TOTAL OTHER COSTS	178,219,377	121,290,503	0	9,425,345	0	
TOTAL PROJECT COSTS	**604,288,336**	**385,371,423**	**0**	**34,854,993**	**0**	**1,024,514,752**

9.3.3 Scenario 4

The capital cost summary for Scenario 4 is presented on the following pages. The total capital requirement is **EUR1,104,241,616** which equates to around **EUR1,406/kW** (based on TCR). Less Owners Soft Costs, this is equivalent to EUR1,285/kW. A graphical representation of the breakdown of costs is shown in Figure 20.

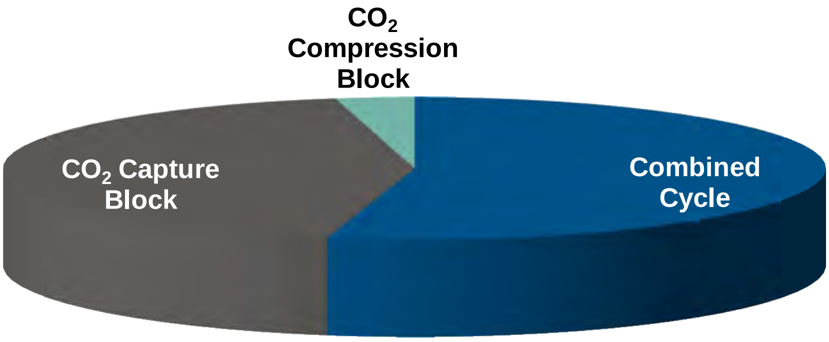

Figure 20 CAPEX breakdown for Scenario 4

As can be seen in Figure 20, the relative contribution of the CO_2 Capture Block to the overall total capital requirement is around 43% (as opposed to 44% for Scenario 3). The increased concentration of CO_2 in the flue gas which is achieved through exhaust gas recirculation (EGR), means that CO_2 is more easily absorbed by the 35%wt MEA solvent and this results in shorter absorber columns and associated packing. In addition, the reduction in flue gas flowrate and pressure drop (caused by recirculation of 50%wt of the flue gas) means that the cross sectional area of the absorber columns can also be reduced, resulting in further CAPEX savings for the absorber columns estimated to be in the region of 22% of the Scenario 3 costs for these items.

Against these capital savings must be weighed the additional costs for the additional flue gas fan, direct contact cooler, and ductwork required to re-circulate and condition the flue-gas prior to return to the GT compressor. However, the study results suggest that the additional costs for these items, are merited by greater cost savings elsewhere.

It should be noted that the Scenario 4 cost estimate presented *does not include for Exhaust Gas Recirculation related modifications to the GT*. Recirculation of a lower O_2 concentration gas stream to the GT may have negative effects on fuel combustion stability and efficiency, which require modification to the machine and/or the combustion systems. It should be noted that development work is ongoing by OEMs to better understand the implications of flue gas recirculation.

A breakdown of the CO_2 Capture Block Major Equipment costs for Scenario 4, by process area, is shown in Table 38;

Table 38 Scenario 4 CO_2 Capture Block cost breakdown

Process Area	Equipment items	Cost Estimate
Flue gas cooling	Ductwork, Flue gas fan #1, Direct Contact Cooler #1 (inc. packing, distributor & collector), DCC Pump#1, and DCC #1 heat exchanger.	EUR5,335,272 (per train)
Flue gas recirculation	Recirculation ductwork, Flue gas fan #2, Direct Contact Cooler #2 (inc. packing, distributor & collector), DCC Pump#2, and DCC #2 heat exchanger.	EUR4,738,006 (per train)
CO_2 absorber & flue gas re-heater	CO_2 absorber (inc. packing and column internals), absorber water wash cooler, absorber water wash pumps, and flue gas re-heater.	EUR26,824,912 (per train)
Rich / Lean amine circulation	Rich solvent pump, Lean / Rich exchanger, lean solvent pump, lean amine cooler, closed loop cooling system, lean solvent filtration system	EUR2,537,394 (per train)
Stripping Section	Stripper columns (inc. packing and column internals), re-boilers, overheads condensers & receivers, reflux pumps, stripper water wash pumps.	EUR58,455,361 (per train)
Ancillaries	Solvent Re-claimer, solvent storage (inc. loading and unloading), raw water system, demineralised water system, firewater water system, nitrogen and compressed air packages.	EUR1,512,986
	Total	**EUR197,294,876**

Project Number:64225A
Project Name:CO_2 Capture at Gas Fired Power Plants Study
Client: IEA Environmental Projects Ltd.

Scenario 4: Combined Cycle Power Plant with Post Combustion Capture and Exhaust Gas Recirculation

Date: 07-3-12
Revision: C

Description	Combined Cycle	CO_2 Capture Block	Reforming Block	CO_2 Compression Block	Common Facilities	
	EUR	EUR	EUR	EUR	EUR	
DIRECT MATERIALS						
Major Equipment	270,098,329	197,294,876	0	16,198,428	0	
Piping	31,095,898	29,594,231	0	1,619,843	0	
Control and Instrumentation	-	3,945,898	0	323,969	0	
Electrical	2,578,284	7,891,795	0	404,961	0	
Solvents, Catalysts & Other Bulk Chemicals	-	1,665,660	0	-	0	
SUB-TOTAL DIRECT MATERIALS	303,772,511	240,392,460	0	18,547,200	0	
SHIPPING / FREIGHT	-	0	0	0	0	
THIRD PARTY INSPECTION	-	0	0	0	0	
SPARE PARTS (Commissioning / 2 Years Operating)	-	0	0	0	0	
SPARE PARTS (Capital / Insurance)	-	0	0	0	0	
SUB-TOTAL MATERIALS	303,772,511	240,392,460	0	18,547,200	0	
MATERIAL AND LABOUR CONTRACTS						
TANKS AND VESSELS	Inc. above	Inc. above		Inc. above		
CIVILS / STEELWORK / BUILDINGS	67,574,372	55,290,266	0	3,709,440	0	
SUB-TOTAL MATERIAL & LABOUR CONTRACTS	67,574,372	55,290,266	0	3,709,440	0	
LABOUR ONLY CONTRACTS						
MECHANICAL	26,108,653	21,635,321	0.00	1,669,248	0.00	
ELECTRICAL / INSTRUMENTATION	7,521,179	7,211,774	0.00	556,416	0.00	
SCAFFOLDING / LAGGING / RIGGING	6,609,956	6,009,811	0.00	463,680	0.00	
SUB-TOTAL LABOUR ONLY CONTRACTS	40,239,788	34,856,906.69	0.00	2,689,344	0.00	
SUB-TOTAL LABOUR AND MATERIALS	411,586,671	330,539,632	0	24,945,984	0	
ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT	13,325,000	9,014,717	0	639,878	0	
COMMISSIONING	2,506,675	1,983,238	0	265,000	0	
SOFT COSTS CONTRACTOR (Inc Contingency & Profit)	110,075,865	99,161,890		5,564,160		
SOFT COSTS OWNER	52,193,837	39,656,988	0	2,782,080	0	
SUB-TOTAL OTHER COSTS	178,101,377	149,816,833	0	9,251,118	0	
TOTAL PROJECT COSTS	**589,688,048**	**480,356,465**	**0**	**34,197,103**	**0**	**1,104,241,616**

9.3.4 Scenario 5

The capital cost summary for Scenario 5 is presented on the following pages. The total capital requirement is **EUR1,494,286,676** which equates to around **EUR1,758/kW** (based on TCR). Less Owners Soft Costs, this is equivalent to EUR1,595/kW. A graphical representation of the breakdown of costs is shown in Figure 21.

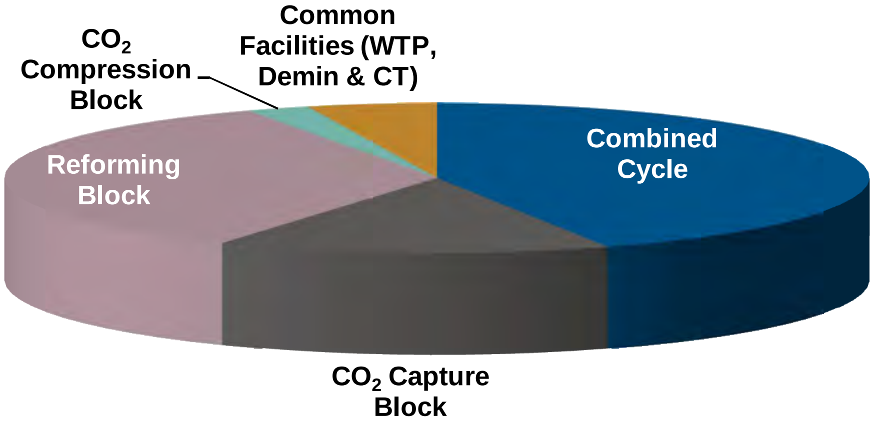

Figure 21 CAPEX breakdown for Scenario 5

CCGT power plant costs account for around 44% (EUR651M) of total capital requirement for Scenario 5, with the Reforming Block accounting for 35% (EUR516M). From a CAPEX perspective, the notable equipment in the Reforming Block includes the auto-thermal reformers and pre-reformers, syngas coolers, HT and LT Shift Reactors, and associated services such as the booster air compressor and furnace pre-heaters.

The CO_2 Capture Block cost is around EUR220M, significantly less than the CO_2 Capture Block cost for Scenario 3 and 4. The principal reason for this is the utilisation of physical solvent absorption with flash separation, which is an viable option in this scenario due to the operating pressure of the process and the CO_2 concentration in the syngas stream. Main elements of the CO_2 Capture Block include the CO_2 absorber, three flash vessels, and a Selexol solvent chiller.

A breakdown of the Direct Material (Major Equipment) costs for Scenario 5, by process area, is shown in Table 39;

Table 39 Scenario 5 process area cost breakdown

Process Area	Equipment items	Cost Estimate
Feedstock Pre-treatment	Furnace Pre-heater, pressure reducing stations, booster air compressor, process air coolers, hydrogenator NG pre-heaters, H_2/N_2 gas compressor, Hydrogenator, Desulphuriser, and Pre-reformer (inc. pre-heater).	EUR17,480,088 (per train)
ATR, Shift Reactors, and Process Steam Generator	Auto-thermal reformer, Process Steam Generator, High temperature shift reactor, Low temperature shift reactor, syngas coolers, and shift reactor product coolers.	EUR81,463,476 (per train)
CO_2 Capture Block	Knock-out drum, Selexol absorber (inc. packing and column internals), Flash drums 1/2/3, solvent recirculation pumps, lean/rich exchanger, solvent chiller, CO_2 absorber gas recycle compressor, and Flash drum 3 booster compressor.	EUR44,322,059 (per train)
Ancillaries	CO_2 vents, flare stack, waste water treatment plant, raw water system, demineralised water system, firewater water system, cooling towers, nitrogen and compressed air packages.	EUR34,056,574
	Total	**EUR320,587,820**

PARSONS BRINCKERHOFF

Project Number:64225A
Project Name:CO_2 Capture at Gas Fired Power Plants Study
Client: IEA Environmental Projects Ltd.

Scenario 5: Combined Cycle Power Plant with Natural Gas Reforming and Pre Combustion Capture

Date: 07-3-12
Revision: C

Description	Combined Cycle	CO_2 Capture Block	Reforming Block	CO_2 Compression Block	Common Facilities (WTP, Demin & CT)	
	EUR	EUR	EUR	EUR	EUR	
DIRECT MATERIALS						
Major Equipment	309,749,805	88,644,118	197,887,128	16,382,765	34,056,574	
Piping	33,271,346	13,296,618	29,683,069	1,638,277	3,405,657	
Control and Instrumentation	-	1,772,882	3,957,743	327,655	681,131	
Electrical	2,939,054	3,545,765	7,915,485	409,569	851,414	
Solvents, Catalysts & Other Bulk Chemicals	-	1,960,784	16,862,745	-	-	
SUB-TOTAL DIRECT MATERIALS	345,960,205	109,220,167	256,306,170	18,758,266	38,994,777	
SHIPPING / FREIGHT	-	0	0	0	0	
THIRD PARTY INSPECTION	-	0	0	0	0	
SPARE PARTS (Commissioning / 2 Years Operating)	-	0	0	0	0	
SPARE PARTS (Capital / Insurance)	-	0	0	0	0	
SUB-TOTAL MATERIALS	345,960,205	109,220,167	256,306,170	18,758,266	38,994,777	
MATERIAL AND LABOUR CONTRACTS						
TANKS AND VESSELS	Inc. above	Inc. above	Inc. above	Inc. above	Inc. above	
CIVILS / STEELWORK / BUILDINGS	67,487,607	25,120,638	58,950,419	3,751,653	7,798,955	
SUB-TOTAL MATERIAL & LABOUR CONTRACTS	67,487,607	25,120,638	58,950,419	3,751,653	7,798,955	
LABOUR ONLY CONTRACTS						
MECHANICAL	29,399,983	9,829,815	23,067,555	1,688,244	3,509,530	
ELECTRICAL / INSTRUMENTATION	8,555,952	3,276,605	7,689,185	562,748	1,169,843	
SCAFFOLDING / LAGGING / RIGGING	7,174,619	2,730,504	6,407,654	468,957	974,869	
SUB-TOTAL LABOUR ONLY CONTRACTS	45,130,554	15,836,924.18	37,164,394.63	2,719,949	5,654,242.70	
SUB-TOTAL LABOUR AND MATERIALS	458,578,366	150,177,729	352,420,984	25,229,868	52,447,975	
ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT	14,892,000	4,095,756	9,611,481	647,160	1,345,320	
COMMISSIONING	2,506,675	901,066	2,114,526	265,000	0	
SOFT COSTS CONTRACTOR (Inc Contingency & Profit)	112,484,117	45,053,319	105,726,295	5,627,480	11,698,433	
SOFT COSTS OWNER	62,272,837	19,659,630	46,135,111	3,376,488	7,019,060	
SUB-TOTAL OTHER COSTS	192,155,629	69,709,771	163,587,413	9,916,128	20,062,813	
TOTAL PROJECT COSTS	**650,733,995**	**219,887,501**	**516,008,397**	**35,145,995**	**72,510,788**	**1,494,286,676**

Over a Century of Engineering Excellence

9.3.5 Scenario 6

The capital cost summary for Scenario 6 is presented on the following page. The total capital requirement is **EUR1,964,580,549** which equates to around **EUR2,666/kW** (based on TCR). Less Owners Soft Costs, this is equivalent to EUR2,421/kW. A graphical representation of the breakdown of costs is shown in Figure 22.

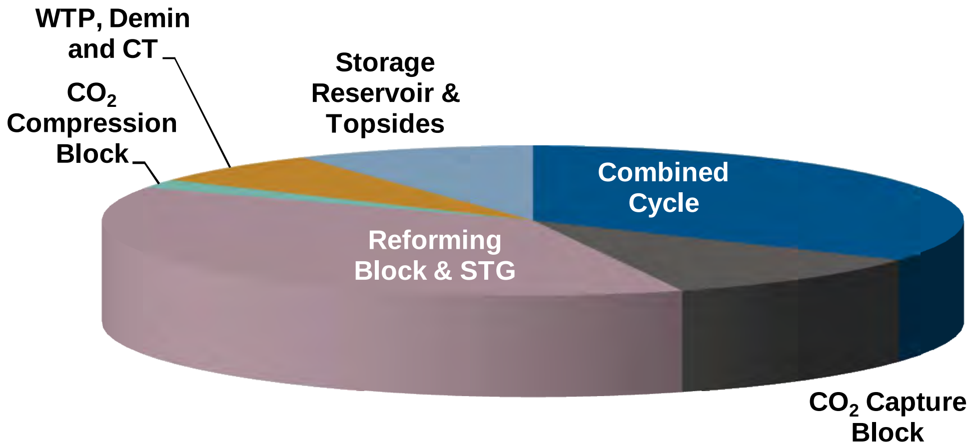

Figure 22 CAPEX breakdown for Scenario 6

As can be seen, the CAPEX requirements for Scenario 6 mark a significant increase over that of Scenario 5. Principally this is due to the addition of a dedicated H_2/N_2 storage site with associated topside facilities, at distance of 50km from the reforming plant, and 5km from the CCGT (see Section 9.3.5.1).

In addition, a stand-alone steam turbine generator is included at the reformer plant, to utilise excess steam produced by the process, and supply the auxiliary power load for the reforming plant. The STG, and associated condenser, cooling tower, and electrical infrastructure, also add significant costs (approx EUR14M) to this scenario.

A breakdown of the Direct Material (Major Equipment) costs for Scenario 6, by process area, is shown in Table 40;

Table 40 Scenario 6 process area cost breakdown

Process Area	Equipment items	Cost Estimate
Feedstock Pre-treatment	Air compressor, Furnace Pre-heater, pressure reducing stations, booster air compressor, process air coolers, hydrogenator NG pre-heaters, H_2/N_2 gas compressor, Hydrogenator, Desulphuriser, and Pre-reformer.	EUR55,535,278 (per train)
ATR, Shift Reactors, and Process Steam Generator	Auto-thermal reformer, Process Steam Generator, High temperature shift reactor, Low temperature shift reactor, syngas coolers, and shift reactor product coolers.	EUR81,550,139 (per train)
CO_2 Capture Block	Knock-out drum, Selexol absorber (inc. packing and column internals), Flash drums 1/2/3, solvent recirculation pumps, lean/rich exchanger, solvent chiller, CO_2 absorber gas recycle compressor, and Flash drum 3 booster compressor.	EUR41,149,770 (per train)
Ancillaries	CO_2 vents, H_2/N_2 pipeline to storage, flare stack, waste water treatment plant, raw water system, demineralised water system, firewater water system, cooling towers, nitrogen and instrument compressed air packages.	EUR62,705,191
Steam Turbine Generator and ancillaries	STG, electrical generator, lubricating oil system, condenser.	EUR14,482,300
	Total	**EUR433,657,865**

9.3.5.1 H_2/N_2 storage site cost estimate

Costs for the H_2/N_2 storage site were estimated assuming on-shore storage in a salt cavern (notionally located in the Zechstein domal salt deposits in NE Netherlands) at a depth of between 4,000 ft and 6,200 ft. It is assumed that the storage cavern has a working capacity of 24bscf (644million Nm^3), equivalent to approximately six weeks of production from the reforming plant, and that the storage cavern operates at around 36.1barg, utilising around 20bscf (537million Nm^3) of base gas to maintain a minimum pressure.

Costs include for work-over / leaching of the salt cavern, H_2/N_2 handling facilities (top-sides equipment), storage wells, and pipelines, more fully detailed in Table 41. *N.B Costs are estimated based on conversion of domal salt caverns, and it is noted that costs for conversion of caverns in bedded salt formations could be considerably higher. It is further acknowledged that costs will depend on local availability of suitable formations.*

Table 41 H_2 / N_2 Storage Cost Breakdown

Item	Estimate (USD)	Estimate (EUR)
Offsite leaching pipelines*	16,450,000	12,337,500
Water Wells / Intake structure	3,950,000	2,962,500
Brine wells / diffusers	23,150,000	17,362,500
Storage wells	46,050,000	34,537,500
Leach plant	36,200,000	27,150,000
Cavern development	80,400,000	60,300,000
Offsite H_2/N_2 pipelines	4,100,000	3,075,000
Gas handling facilities	26,000,000	19,500,000
Total	236,300,000	177,225,000
USD/bscf of working gas	9.85	

** It should be noted that work-over of salt caverns necessitates utilisation of significant quantities of water (in Scenario 6, potentially 4,500gpm), to leach the salt caverns. Similar quantities of brine which is produced by the leaching process must be also disposed of. Costs for water extraction and brine treatment and disposal have not been included for in the cost estimate.*

The total capital requirement for the H_2/N_2 storage site is therefore estimated at **EUR177,225,000**.

It is noted that in Scenario 6 the H_2/N_2 storage site is dedicated to one reforming plant, and one CCGT. In reality, the significant costs associated with gas storage are typically offset against multiple assets, in order to maximise operational flexibility across the fleet, and fully recognise trading opportunities in electricity and fuel markets. It is noted that the limitations of this study are such that these benefits could not be considered further.

PARSONS BRINCKERHOFF

Project Number:64225A
Project Name:CO_2 Capture at Gas Fired Power Plants
Study Client: IEA Environmental Projects Ltd.

Scenario 6: Natural Gas Reforming and Pre Combustion Capture, and Remote Combined Cycle Power Plant

Date: 07-3-12
Revision: C

Description	Combined Cycle	CO_2 Capture Block	Reforming Block & STG	CO_2 Compression Block	WTP, Demin and CT	Storage Reservoir & Topsides	
	EUR	EUR	EUR	EUR	EUR		
DIRECT MATERIALS							
Major Equipment	311,992,310	82,299,539	288,653,133	16,673,918	62,705,191		
Piping	31,594,323	12,344,931	43,297,970	1,667,392	6,270,519		
Control and Instrumentation	-	1,645,991	5,773,063	333,478	1,254,104		
Electrical	3,086,636	3,291,982	11,546,125	416,848	1,567,630		
Solvents, Catalysts & Other Bulk Chemicals	-	1,960,784	16,862,745	-	-		
SUB-TOTAL DIRECT MATERIALS	346,673,269	101,543,226	366,133,036	19,091,636	71,797,444		
SHIPPING / FREIGHT	-	0	0	0	0		
THIRD PARTY INSPECTION	-	0	0	0	0		
SPARE PARTS (Commissioning / 2 Years Operating)	-	0	0	0	0		
SPARE PARTS (Capital / Insurance)	-	0	0	0	0		
SUB-TOTAL MATERIALS	346,673,269	101,543,226	366,133,036	19,091,636	71,797,444		
MATERIAL AND LABOUR CONTRACTS							
TANKS AND VESSELS	Inc. above	Inc. above	Inc. above	Inc. above	Inc. above		
CIVILS / STEELWORK / BUILDINGS	66,423,835	23,354,942	84,210,598	3,818,327	14,359,489		
SUB-TOTAL MATERIAL & LABOUR CONTRACTS	66,423,835	23,354,942	84,210,598	3,818,327	14,359,489		
LABOUR ONLY CONTRACTS							
MECHANICAL	29,936,472	9,138,890	32,951,973	1,718,247	6,461,770		
ELECTRICAL / INSTRUMENTATION	14,038,740	3,046,297	10,983,991	572,749	2,153,923		
SCAFFOLDING / LAGGING / RIGGING	7,285,281	2,538,581	9,153,326	477,291	1,794,936		
SUB-TOTAL LABOUR ONLY CONTRACTS	51,260,493	14,723,767.80	53,089,290.21	2,768,287	10,410,629.34		
SUB-TOTAL LABOUR AND MATERIALS	464,357,597	139,621,936	503,432,924	25,678,251	96,567,562		
ENGINEERING SERVICES / CONSTRUCTION MANAGEMENT	14,838,000	3,807,871	13,729,989	658,661	2,477,012		
COMMISSIONING	2,506,675	837,732	3,020,598	265,000	0		
SOFT COSTS CONTRACTOR (Inc Contingency & Profit)	114,324,838	41,886,581	151,029,877	5,727,491	21,539,233		
SOFT COSTS OWNER	69,334,654	20,308,645	73,226,607	3,818,327	14,359,489		
SUB-TOTAL OTHER COSTS	201,004,167	66,840,829	241,007,071	10,469,480	38,375,734		
TOTAL PROJECT COSTS	**665,361,764**	**206,462,765**	**744,439,995**	**36,147,730**	**134,943,295**	**177,225,000**	**1,964,580,549**

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9.4 Operating cost summary for each scenario

This section presents the operating costs estimates for each scenario. Operating costs are presented as fixed costs, such as long term service agreement (LTSA) costs (typically presented as a fixed cost per fired hour), and routine maintenance costs, and variable costs such as waste disposal costs and consumables. Operating cost assumptions are based on Parsons Brinckerhoff in-house knowledge for established technology such as the CCGT plant, and estimated as a percentage of TPC where no reference projects were available.

9.4.1 Scenario 1

LTSA costs for Scenario 1 are estimated at EUR660 per fired hour, based on Parsons Brinckerhoff's experiential data of plant of this size. Likewise Routine maintenance costs for the CCGT, have been estimated as EUR9.5M per annum.

Consumables for the CCGT include chemicals for boiler feed water treatment, waste water treatment, lubricants for rotating plant, and raw water consumption & treatment costs. The total consumable costs for Scenario 1 are estimated as EUR¢2.2/MWh, also based on Parsons Brinckerhoff experience with plant of this size.

9.4.2 Scenario 3

LTSA costs for Scenario 3 are estimated at EUR1,132 per fired hour, based on the Specific Cost (TPC) of this scenario. Routine maintenance costs for the Scenario, have been estimated as EUR16.30M, which includes around EUR10M for annual maintenance of the carbon capture plant (based on advice provided by technology providers).

Consumables for Scenario 3 include 35%wtMEA solvent make-up, chemicals for boiler feed water treatment, waste water treatment, lubricants for rotating plant, and raw water consumption & treatment costs. Of particular significance are the solvent make-up costs, since MEA solvent degrades over time and must be replaced at a rate of around 1.6kg per tonne of CO_2 captured[13]. The total consumable costs for Scenario 3 are estimated as EUR¢181.53/MWh.

The costs for consumables for proprietary solvent systems are lower than that of Scenario 3, by virtue of lower solvent degradation (and replacement) rates, although it should be noted that proprietary solvents are typically more expensive than MEA solution. The lower degradation rates also lead to lower waste disposal costs. The total consumable costs for Scenario 3b (based on averaged data from solvent suppliers) are estimated as EUR¢136.68/MW/hr. LTSA costs for Scenario 3b are estimated at EUR959 per fired hour. Routine maintenance costs for the scenario have been estimated as EUR13.80M.

9.4.3 Scenario 4

LTSA costs for Scenario 4 are estimated at EUR1,034 per fired hour, based on the Specific Cost (TPC) of this scenario. Routine maintenance costs for the facility including the CCGT have been estimated as EUR14.885M.

Consumables for Scenario 4 include 35%wtMEA solvent make-up, chemicals for boiler feed water treatment, waste water treatment, lubricants for rotating plant, and raw water consumption & treatment costs. The total consumable costs for Scenario 4 are estimated as EUR¢180.52/MWh.

9.4.4 Scenario 5

LTSA costs for Scenario 5 are estimated at EUR1,389 per fired hour, based on the Specific Cost (TPC) of this scenario. Routine maintenance costs for the facility including the CCGT have been estimated as EUR19.99M, which includes for annual replacement of catalysts in the reforming plant (estimated at around 4% of TPC for the Reformer block).

Consumables for Scenario 5 include Selexol make-up, chemicals for boiler feed water treatment, waste water treatment, lubricants for rotating plant, and raw water consumption & treatment costs. Of particular significance are the boiler feed-water treatment costs, owing to the significant consumption of process steam by the auto-thermal reformer. The total consumable costs for Scenario 5 are estimated as EUR¢144.73/MWh.

9.4.5 Scenario 6

LTSA costs for Scenario 6 are estimated at EUR1,827 per fired hour, based on the Specific Cost (TPC) of this scenario. Routine maintenance costs for the facility including the CCGT have been estimated as EUR26.30M, which includes for annual replacement of catalysts in the reforming plant.

Consumables for Scenario 6 include Selexol make-up, chemicals for boiler feed water treatment, waste water treatment, lubricants for rotating plant, and raw water consumption & treatment costs. The total consumable costs for Scenario 6 are estimated as EUR¢219.46/MWh, reflecting the additional rotating plant required for this scenario (air compressors and H_2/N_2 fuel compressors for transportation to the storage site and remote CCGT.

10. ECONOMIC EVALUATION

10.1 Introduction

The previous sections of this report have outlined and discussed the baseline technical performance parameters of the scenarios considered as part of this study. The plant technologies under consideration are:

- A typical CCGT plant with a net power output of 910 MW (referred to as Scenario 1);
- A CCGT plant with Post Combustion Capture with a net power output of 789 MW (referred to as Scenario 3);
- A CCGT plant with Post Combustion Capture (using a Proprietary System) with a new power output of 804 MW (referred to as Scenario 3b);
- A CCGT plant with Post Combustion Capture and Exhaust Gas Re-circulation with a net power output of 786 MW (referred to as Scenario 4);
- A CCGT plant with Natural Gas Reforming and Pre Combustion Capture with a net power output of 850 MW (referred to as Scenario 5); and
- Natural Gas Reforming and Pre Combustion Capture with Remote CCGT with a net power output of 737 MW (referred to as Scenario 6).

The purpose of this section of the report is to present and analyse the lifetime cost of generation for each of the scenarios, under a range of feasible options, for important factors such as gas price, carbon price and discount rate.

This section will begin, however, by outlining the methodology adopted in determining the lifetime cost of generation for each scenario and the base case modelling assumptions.

10.2 Economic criteria and starting assumptions

In order to determine the lifetime cost of generation for each of the scenarios under consideration, Parsons Brinckerhoff has used a Discounted Operational Cash Flow (DOCF) model. This type of model is widely used as a method for analysing power system costs.

The model calculates the annual costs relating to each aspect of the generating plants' construction and subsequent operation and maintenance (O&M). The core cost streams captured by the DOCF model are:

- Capital expenditure (including plant EPC, IDC, owners costs, working capital and start up costs);
- Fuel costs;
- The cost of CO_2 emissions (Carbon Emissions Penalty);
- The cost of CO_2 transportation and storage;
- Operating costs (including routine maintenance, variable O&M costs and consumables); and,
- Overhead costs (including insurance, salaries, business rates and administrative overhead costs).

Many of these cost streams are directly related to the projected technical performance of the plant under consideration such that plant power output, efficiency, capacity factor, carbon emissions/capture rates impact directly on the costs streams.

The calculations assume that the investments are financed ‘on the balance sheet’ by market participants. This removes the complexity of using project debt/equity structures. The calculations do not take account of taxation or capital allowances and are intended to provide an indication of the costs associated with the production of electricity from the different technologies at the point of connection to the electricity grid.

Whilst the geographic point of connection of a power generator to the electricity network does affect the total costs of providing that power to the electricity market, the costs that arise due to transmission and distribution charges and the ‘use of system’ charging applied by distribution or transmission network operators are not included in the modelled costs. Parsons Brinckerhoff believes that this allows for a fair comparison between technology types, given that use of system charges are country and location specific.

The lifetime cost of generation results produced by the DOCF model are presented for each of the key cost components detailed above. The DOCF model assumes that all future cost streams are equally spaced and occur at the end of each year. To ensure a consistent and fair comparison between scenarios, the cost streams are subsequently discounted using a standard ‘year-end’ discounting technique.

A detailed breakdown of the lifetime cost of generation will provide a clear understanding of the cost make-up in each scenario and the relative costs contributions between competing technologies. The typical CCGT plant (Scenario 1) will provide the baseline for comparison against the various carbon capture technology options.

10.3 Input Assumptions

In this sub-section Parsons Brinckerhoff set out the key base case modelling assumptions adopted for the calculation of the lifetime cost of generation. A summary of the base case modelling assumptions are presented in Appendix F.

The data used within the DOCF model is based upon information either owned by Parsons Brinckerhoff through the company's involvement in the power generation industry (either acting for project developers, project financiers or project operators), publicly available documentation or based on the IEAGHG report entitled 'Criteria for Technical and Economic Assessment of Plant with Low CO_2 Emissions (May 2009)'.

10.3.1 Technical Performance Parameters

The base case technical and performance parameters of the scenarios under consideration are discussed in detail in Sections 2 to 7 of this report. The key technical performance parameters required for lifetime cost modelling are summarised in Table 42 below.

Table 42 Baseline Technical Performance Parameters

	S1: CCGT	S3: CCGT with Post Combustion Capture	S3B: CCGT with Post Combustion Capture (Proprietary System)	S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT
Primary Fuel Used	Gas	Gas	Gas	Gas	Gas	Gas
Net Power Output (MW)	910.3	789.3	804.0	785.5	849.9	736.8
First Year Capacity Factor (%)	90%	60%	60%	60%	60%	60%
Capacity Factor (%)	93%	90%	90%	90%	85%	85%
Plant Efficiency @ LHV (%)	58.9%	51.0%	52.0%	51.3%	42.3%	36.8%
Heat Rate @ LHV (kJ / kWh)	6115	7053	6926	7015	8510	9795
CO2 Emitted (kg / MWh)	348	41	40	41	89	104
CO2 Stored (kg / MWh)	0	365	359	362	395	454

The typical net power output of the six scenarios ranges from 737 MW to around 910 MW.

The assumed capacity factors are used to directly determine the number of operating hours for each plant and when combined with the net power output assumption, the annual generation is determined. The capacity factor for a typical CCGT plant (Scenario 1) is assumed to be 90% in the first year of operation (7884 operating hours), rising to 93% for the remaining years of the plants' economic life (8147 operating hours). The capacity factor for the CCGT plants with Post Combustion Capture facilities (Scenarios 3, 3b and 4) is assumed to be 60% in the first year of operation (5238 operating hours), rising to 90% for the remaining years of the plants' economic life. The capacity factor for the CCGT plants with Pre Combustion Capture (Scenarios 5 and 6) is assumed to be 60% in the first year of operation, rising to 85% (7446 operating hours) for the remaining years of the plants' economic life. All assumptions regarding capacity factors have been based (as far as possible) on Parsons Brinckerhoff experience of similar plant, or through consultation with technology vendors.

Plant efficiency assumptions are used within the DOCF model to accurately determine the amount of fuel consumed by each plant. In terms of plant efficiencies, the typical CCGT plant is the most efficient plant (59% LHV), followed by the Post Combustion plants (around 51 to 52% LHV) and then the Pre Combustion plants (around 37 to 42% LHV).

The generation of electricity from each of the six scenarios leads to the emission of CO_2 into the atmosphere in varying degrees of severity. The reference CCGT plant (Scenario 1) is the heaviest emitter of CO_2 of the six scenarios, with an emission rate of 348 kg of CO_2 per MWh. The scenarios which utilise carbon capture technology emit significantly less CO_2. The Post Combustion Capture plants emit approximately 40 - 41 kg of CO_2 per MWh (around one ninth of the level of emissions from a typical unabated CCGT plant). The Pre Combustion plants are assumed to emit approximately 89 - 104 kg of CO_2 per MWh (around one third, or one quarter of the level of emissions from a typical CCGT plant).

Conversely, without any carbon capture facilities, the CO_2 storage rate for the typical CCGT plant is assumed to be zero. The CO_2 storage rate of the Post Combustion Capture plants is assumed to range between 359 - 365 kg of CO_2 per MWh. The CO_2 storage rate of the Pre Combustion Capture plants is assumed to range between 395 - 454 kg of CO_2 per MWh.

10.3.2 Capital Expenditure

Capital expenditure comprises of:

- The Engineering, Procurement and Construction (EPC) Capital Cost;
- Interest During Construction (IDC);
- Owners costs;
- Working capital; and,
- Start up costs.

Table 43 presents the capital expenditure assumptions for each of the scenarios.

Table 43 Capital Cost Assumptions

	S1: CCGT	S3: CCGT with Post Combustion Capture	S3B: CCGT with Post Combustion Capture (Proprietary System)	S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT
Financial Disbursement Period (Years)	4	4	4	4	4	4
Specific EPC Capital Cost (EUR / kW)	637.1	1400.7	1164.5	1285.3	1595.2	2420.6
Capital Disbursements (% of total)						
First Year of Commercial Operation (O)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Final Year of Construction (C)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
C – 1	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
C – 2	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
C – 3	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
C – 4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C – 5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Owners Costs (% of EPC cost)	9.0%	9.4%	9.4%	9.4%	10.2%	10.2%
Consumables Storage (Days)	30	30	30	30	30	30
Start Up - Labour (Months)	3	3	3	3	4	4
Start Up - Maintenance (Months)	1	1	1	1	1	1
Start Up - Consumables (Months)	1	1	1	1	1	1
Start Up - Fuel (Months)	1	1	1	1	1	1

A detailed description of the capital costs for each of the scenarios is presented in Section 0 of this report. For lifetime cost modelling purposes the capital costs presented in Section 0 have been converted into two separate components. These components are:

- An EPC cost per kW_{net}; and,
- An owners soft cost (derived as a percentage of the total EPC cost).

The EPC cost presented in Table 43 is derived by dividing the TPC (i.e. TCR less Owners Soft costs) by the net power output of the plant. The EPC costs range from EUR 637 per kW for a typical CCGT plant to EUR 2421 per kW for a Natural Gas Reforming and Pre-Combustion, Capture with Remote CCGT plant.

The EPC costs presented above are reflective of overnight costs and therefore do not include IDC. IDC is derived separately in the DOCF model using the assumed study discount rate (see Section 10.3.5 for details) and assumptions relating to capital disbursement. *N.B It should be noted that the defined financial disbursement period relates to the full period over which capital is expended and is not only the physical construction period.*

The capital disbursements are assumed to remain constant for each scenario, and are as follows:

- 15% of all capital expenditure is assumed to be incurred 4 years prior to commercial operation;
- 35% of all capital expenditure is assumed to be incurred 3 years prior to commercial operation;
- 40% of all capital expenditure is assumed to be incurred 2 years prior to commercial operation; and
- 10% of all capital expenditure is assumed to be incurred in the final year of construction.

Owners soft costs are derived separately from the plant cost expenditure. Owners soft costs are derived as a percentage of total EPC costs and are assumed to range from between 9.0% (for the typical CCGT plant), to 9.4% (for the post-combustion plant) and to 10.2% (for the pre-combustion plant) of the total EPC cost. The DOCF model assumes that owners soft costs are incurred during the first year of financial disbursement and do not include IDC.

In terms of working capital, all scenarios are assumed to require sufficient working capital to cover the cost of 30 days worth of consumables. Consumables includes items such as chemicals for boiler feed water treatment, wastewater treatment and solvents for the carbon capture process. Working capital expenditure is incurred the year prior to commercial operation of the plant. The working capital consumables cost is determined by deriving the theoretical expenditure on consumables over 30 days if the plant were operating at full load throughout the year.

Whilst there are no working capital allowances made for gas for any of the plant options, it should be noted that the Natural Gas Reforming and Pre Combustion Capture with Remote CCGT plant (Scenario 6) gains a significant benefit from the storage of an intermediate fuel (hydrogen), which permits greater operational flexibility and allows electricity/fuel trading opportunities. A description of this storage arrangement is discussed in Section 7.2.2 of this report. The DOCF model does not take into account the benefits of storing intermediate fuels.

Start up expenditure is incurred the year prior to commercial operation of the plant and is assumed to be fairly consistent between all of the scenarios. All Scenarios are assumed to require one months maintenance, fuel and consumables start up costs. Labour start up costs are assumed to be the equivalent of three months salary costs for Scenarios 1, 3, 3b and 4 and the equivalent of four months salary costs for Scenarios 5 and 6, based on Parsons Brinckerhoff estimates of commissioning period durations for each scenario.

10.3.3 Operation & Maintenance Costs

Table 44 presents the O&M costs associated with each scenario. The O&M costs are incurred throughout the economic life of the project and are based on variable and fixed routine maintenance costs in addition to consumable costs relating to the energy generated from the plant.

Table 44 Operational and Maintenance Costs

	S1: CCGT	S3: CCGT with Post Combustion Capture	S3B: CCGT with Post Combustion Capture (Proprietary System)	S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT
VOM or LTSA (cost per fired-hour (EUR))	660	1,132	959	1,034	1,389	1,827
Routine Maintenance Costs (EUR '000 p.a.)	9,500	16,300	13,803	14,885	19,989	26,295
Other Consumables (EUR¢ / MWh)	2.20	181.53	136.68	180.52	144.73	219.46

The cost of a LTSA or that of undertaking Variable O&M (VOM) is assumed to range significantly between the scenarios. The lowest LTSA/VOM cost is EUR 660 per fired-hour (for a typical CCGT plant – Scenario 1). The highest LTSA/VOM cost is almost three times higher than the LTSA/VOM cost associated with a typical CCGT plant, owing to the significant additional complexity. The LTSA/VOM cost for a CCGT with Natural Gas Reforming and Pre-Combustion Capture Plant is calculated to be EUR 1827 per fired hour.

Routine maintenance costs follow a similar pattern to the LTSA/VOM costs, with the routine maintenance cost of the typical CCGT plant being the lowest cost (EUR 9.5M per annum) and the CCGT with Natural Gas Reforming and Pre-Combustion Capture Plant being almost three times higher at EUR 26.3M per annum.

The cost of 'Other Consumables' are assumed to range dramatically. The cost of consumables for a typical CCGT plant is assumed to be EUR¢ 2.2 per MWh, whilst the cost of consumables for Scenarios 3, 3B, 4 and 5 are assumed to range between EUR¢ 137 - EUR¢ 182 per MWh. The main contributor to the cost of consumables for the Post-Combustion plants is the solvent which must be replaced at a rate of around 1.6kg per tonne of CO_2 captured (it should be noted that the replacement rate for a proprietary solvent can potentially be significantly lower - in the region of 20% to 30% that of 35%wt MEA). The cost of consumables for Scenario 6 is assumed to be significantly higher at EUR¢ 219 per MWh.

10.3.4 Overhead Costs

General overheads are assumed to comprise a General Admin Charge, Salaries (permanent staff), Business Rates and Insurance. The overhead costs are assumed to be incurred during each year of operation, regardless of the capacity factor/plant output. The overhead costs are assumed to remain constant (in real terms) over the course of the projects economic life.

In order to determine the overhead costs of each scenario, cost assumptions have been made in relation to:

- The number of permanent staff required at each plant;
- Their salary costs;
- A specific charge for general administration costs associated with operating a power plant site;
- Rateable values;
- A national non-domestic multiplier (NNDM); and
- A specific insurance cost.

Table 45 presents the assumed overhead costs associated with each scenario.

Table 45 Overhead Costs

	S1: CCGT	S3: CCGT with Post Combustion Capture	S3B: CCGT with Post Combustion Capture (Proprietary System)	S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT
Number of Permanent staff	50	79	79	79	101	107
Average Salary (EUR '000)	60	60	60	60	60	60
Total Salary Costs (EUR '000)	3,000	4,740	4,740	4,740	6,060	6,420
Specific General & Admin Cost (EUR / kW)	3.14	4.36	4.36	4.36	4.36	4.36
Total General & Admin Cost (EUR '000 p.a.)	2,858	3,441	3,505	3,425	3,706	3,212
Rateable Value (EUR / MW 2010)	5,958	6,234	6,234	6,234	6,542	6,542
NNDM (EUR¢ per EUR)	47.20	47.20	47.20	47.20	47.20	47.20
Business Rates (EUR / MW DNC)	2,812	2,942	2,942	2,942	3,087	3,087
Specific Insurance Cost (EUR / kW)	2.50	4.45	4.45	4.45	4.45	4.45
Total Insurance Cost (EUR '000 p.a.)	2,276	3,513	3,578	3,496	3,782	3,279

The number of permanent staff for each scenario has been determined using Parsons Brinckerhoff's experience and knowledge of the technologies under consideration. The salary costs reflect those outlined in the IEAGHG report entitled 'Criteria for Technical and Economic Assessment of Plant with Low CO_2 Emissions (May 2009)'.

General administration costs, business rates and insurance costs have also been determined using PB's experience and knowledge of the technologies under consideration.

Business rates are estimated by multiplying the assumed rateable value (representative of the open market annual rental value of a business / non-domestic property) by the national non-domestic multiplier (NNDM - the rate in the pound by which the rateable value is multiplied to produce the annual rate bill for a property). The NNDM is set at EUR¢ 47.2 per EUR.

N.B It should be noted that this parameter will be country specific but the value applied in this model is based on the UK 2010/11 NNDM of GBP pence *41.4 per GBP and a EUR to GBP exchange rate of 1.14. The local value for this study could not be identified but will vary based on taxation arrangements for a given region.*

10.3.5 Economic Assumptions

All costs are stated in Euros (EUR and EUR¢) and are defined in constant (real) prices as of January 2011. Inflation is excluded from the analysis on the assumption that inflation will affect all costs equally.

Each scenario is assumed to have an economic lifespan of 25 years, as detailed in the IEAGHG report entitled ‘Criteria for Technical and Economic Assessment of Plant with Low CO_2 Emissions (May 2009).

The discount rate appropriate to a specific project is dependent upon the maturity of the technology, the residual risks within the project and site specific issues. The baseline discount rate for this study is assumed be 8%, which is typical for the rates used for projects similar to the reference plant. Sensitivity to higher and lower discount rates are further considered in Section 10.5.4.

10.3.6 Gas Price

International and localised gas price forecasts are available from a number of reputable sources. It should be noted however, that gas prices in recent years have fluctuated with a considerable degree of variability and previous predictions of future gas prices have been subject to large degrees of error. Whilst a varying gas price forecast may perhaps be the most realistic assumption to make, the future of the price of gas remains uncertain over the time frame of the study.

As a result, in order to retain consistency with other IEAGHG studies and to ensure the ability of readers to compare the results with previous work, this study assumes that the base case cost of gas is a constant EUR 6 per GJ (LHV). Sensitivity to higher and lower gas prices are further considered in Section 10.5.1.

10.3.7 Carbon Emissions Penalty and the Cost of CO_2 Transportation & Storage

The generation of electricity from each of the scenarios under consideration will lead to the emission of CO_2 into the atmosphere (in varying degrees of severity). Under proposed carbon emissions legislation, the emission of CO_2 will incur a charge on the generator, per unit of CO_2 emitted. This charge (referred to as the ‘Carbon Emissions Penalty’) is expected to increase (in real terms) over the coming years and to a large extent is likely to be fixed by policy makers through national and international CO_2 emission reduction targets. Sensitivity to higher and lower carbon emissions penalties and CO_2 transportation and storage costs are further considered in Section 10.5.2 and Section 10.5.3 respectively.

Nevertheless, it is assumed for this study that the base case Carbon Emissions Penalty is a constant EUR 10 per tonne of CO_2 emitted, which reflects the EUA (EU allowance) unit prices at the time of this study.

Whilst scenarios 3, 3b, 4,5 and 6 are all equipped with carbon capture technology (and thus emit less CO_2 per unit of generation than Scenario 1), there is a variable cost associated with the transportation and storage of the CO_2 captured at these plants. This variable cost allows for capital expenditure and operating costs of the wells and compressors used to store the CO_2 safely and securely.

This study assumes that the base case cost of CO_2 transportation and storage is a constant EUR 5 per tonne of CO_2 stored, as agreed with the IEAGHG, and in alignment with 'Criteria for Technical and Economic Assessment of Plant with Low CO_2 Emissions (May 2009). Sensitivity to higher and lower CO_2 transportation and storage costs are further considered in Section 10.5.3.

10.4 Lifetime Cost of Generation - Base Case Results

The base case lifetime costs of generation derived for the six scenarios are presented in Table 46 and Table 47 below.

Table 46 Lifetime Cost of Electricity (EUR¢ per kWh) - Base Case

Base Case	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.03	3.67	0.35	0.00	0.20	0.14	5.39
S3: CCGT with Post Combustion Capture	2.38	4.23	0.04	0.18	0.59	0.23	7.66
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.98	4.16	0.04	0.18	0.48	0.23	7.07
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.18	4.21	0.04	0.18	0.56	0.23	7.41
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.88	5.11	0.09	0.20	0.63	0.26	9.17
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.35	5.88	0.10	0.23	0.96	0.28	11.80

Table 47 Contribution to Lifetime Cost of Electricity (%) - Base Case

Base Case	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	19.1%	68.0%	6.5%	0.0%	3.8%	2.7%	100.0%
S3: CCGT with Post Combustion Capture	31.0%	55.3%	0.5%	2.4%	7.8%	3.0%	100.0%
S3B: CCGT with Post Combustion Capture (Proprietary System)	28.0%	58.8%	0.6%	2.5%	6.8%	3.3%	100.0%
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	29.5%	56.8%	0.5%	2.4%	7.6%	3.1%	100.0%
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	31.4%	55.7%	1.0%	2.2%	6.9%	2.9%	100.0%
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	36.8%	49.8%	0.9%	1.9%	8.1%	2.4%	100.0%

As shown in the first line of Table 46 and Table 47, the total lifetime cost of generation for a typical CCGT plant (Scenario 1) is estimated at EUR¢ 5.39 per kWh. This cost is driven by expenditure on fuel which accounts for 68% of the total lifetime cost (the equivalent of EUR¢ 3.67 per kWh). The second largest lifetime cost component of the typical CCGT plant is capital expenditure which accounts for 19.1% of the total lifetime cost. The Carbon Emission Penalty equates to approximately 6.5% of the total lifetime cost and O&M costs and general overhead costs account for the remaining 6.4% of the total lifetime cost.

As shown in the second line of Table 46 and Table 47, the total lifetime cost of generation for a CCGT plant with Post Combustion Capture technology (Scenario 3) is estimated at EUR¢ 7.66 per kWh, 42% higher than the lifetime cost of Scenario 1. Whilst the total expenditure on fuel is higher than that for a typical CCGT plant (EUR¢ 4.23 per kWh - primarily due to the lower efficiency of the plant), and whilst the cost of fuel still drives the total lifetime cost, fuel accounts for a smaller proportion of the total lifetime cost when compared to Scenario 1 at 55.3%. The contribution cost per kWh from capital expenditure has increased when compared to Scenario 1 - rising from EUR¢ 1.03 per kWh to almost EUR¢ 2.38 per kWh - and accounts for 31% of the total lifetime cost. This reflects the additional capital expenditure required to install the carbon capture and storage facilities in Scenario 3.

Due to the carbon capture and storage technology being fitted, the cost of CO_2 emissions (i.e. the Carbon Emissions Penalty) is lower (accounting for only 0.5% of the total lifetime cost). The capture of CO_2 in Scenario 3 is reflected by the need for expenditure on CO_2 transportation and storage, which contributes to around 2.4% to the total lifetime costs. O&M costs and general overhead costs are significantly higher for Scenario 3 than for Scenario 1, accounting for around 10.8% of the total lifetime cost.

The third line of Table 46 and Table 47 shows that the total lifetime cost of generation for a CCGT plant with Post Combustion Capture technology utilising a Proprietary System (Scenario 3b) is estimated at EUR¢ 7.07 per kWh. The total lifetime cost, is composed of

EUR¢ 1.98 per kWh from capital expenditure (28% of the total lifetime cost) and EUR¢ 4.16 per kWh from fuel (58.8% of the total lifetime cost). The Carbon Emissions Penalty accounts for 0.6% of the total lifetime cost, the cost of CO_2 transportation and storage accounts for 2.5% of the total lifetime cost and O&M costs and general overhead costs account for 10.1% of the total lifetime cost.

The fourth line of Table 46 and Table 47 shows that the total lifetime cost of generation for a CCGT plant with Post Combustion Capture and Flue Gas Recirculation technology (Scenario 4) is estimated at EUR¢ 7.41 per kWh (37% higher than the total lifetime cost of Scenario 1 but only 3% lower the total lifetime cost of Scenario 3). The contributions to the total lifetime cost in Scenario 4 are similar to those for Scenario 3; fuel accounts for 56.8%, capital expenditure accounts for 29.5%, CO_2 emissions account for 0.5%, CO_2 transportation and storage accounts for 2.4% and O&M costs and general overhead costs account for around 10.7% of the total lifetime cost.

The fifth line of Table 46 and Table 47 shows that the total lifetime cost of generation for a CCGT plant with Natural Gas Reforming and Pre Combustion Capture technology (Scenario 5) is estimated at EUR¢ 9.17 per kWh. This total lifetime cost is approximately 70% higher than the total lifetime cost of Scenario 1 and approximately 20%, 30% and 24% higher than the total lifetime cost of Scenario 3, Scenario 3b and Scenario 4 respectively. Whilst the total expenditure on fuel is higher than that spent in Scenario 3, 3b and 4 (EUR¢ 5.11 per kWh - primarily due to the lower efficiency of the plant), and whilst the cost of fuel still drives the total lifetime cost, fuel accounts for a smaller 55.7% of the total lifetime cost when compared to Scenario 1. The contribution from capital expenditure has increased when compared to Scenario 1, 3, 3b and 4, to EUR 2.88 per kWh (although the overall contribution to the total lifetime costs from capital expenditure is similar to Scenario 3 at around 31.4%). This reflects the additional capital expenditure required to install the pre-combustion technology compared to post-combustion technology.

Due to the carbon capture and storage technology being fitted, the Carbon Emissions Penalty is expected to be much lower in comparison to a typical CCGT plant, but not as low as the expected cost of CO_2 emissions from scenarios 3, 3b and 4. Accordingly, the Carbon Emissions Penalty accounts for 1% of the total lifetime cost, or EUR¢ 0.09 per kWh. The capture of CO_2 in Scenario 5 is reflected by the need for expenditure on CO_2 transportation and storage, which contributes to around 2.2% to the total lifetime costs. O&M costs and general overhead costs account for 9.8% of the total lifetime cost.

As shown in the bottom line of Table 46 and Table 47, the lifetime cost of generation for a Natural Gas Reforming and Pre Combustion Capture with remote CCGT plant (Scenario 6) is estimated at EUR¢ 11.80 per kWh. This total lifetime cost is approximately 119% higher than the total lifetime cost of Scenario 1, approximately 54% higher than the total lifetime cost of Scenario 3, approximately 67% higher than the total lifetime cost of

Scenario 3b, 59% higher than the total lifetime cost of Scenario 4 and 29% higher than the total lifetime cost of Option 5. The contribution to the total lifetime cost from fuel is the lowest of the six scenarios under consideration (accounting for only 49.8% of the total lifetime cost), although actual expenditure on fuel is expected to be the highest (EUR¢ 5.88 per kWh – more than the total lifetime cost of a typical CCGT plant!). The additional facilities required in Scenario 6 mean that the lifetime cost contribution of capital expenditure is around EUR¢ 4.35 per kWh (accounting for 36.8% of the total lifetime cost). The lifetime cost of CO_2 emissions from Scenario 6 are similar to those of Scenario 5, accounting for around 0.9% of the total lifetime cost. The lifetime cost contribution of CO_2 transportation and storage is similar to that in scenarios 3 to 5 at around EUR¢ 0.23 per kWh, although this only equates to 1.9% of the total lifetime cost. O&M costs and general overhead costs account for 10.5% of the total lifetime cost.

Figure 23 and Figure 24 below provide a graphical representation of the lifetime costs of generation for the scenarios.

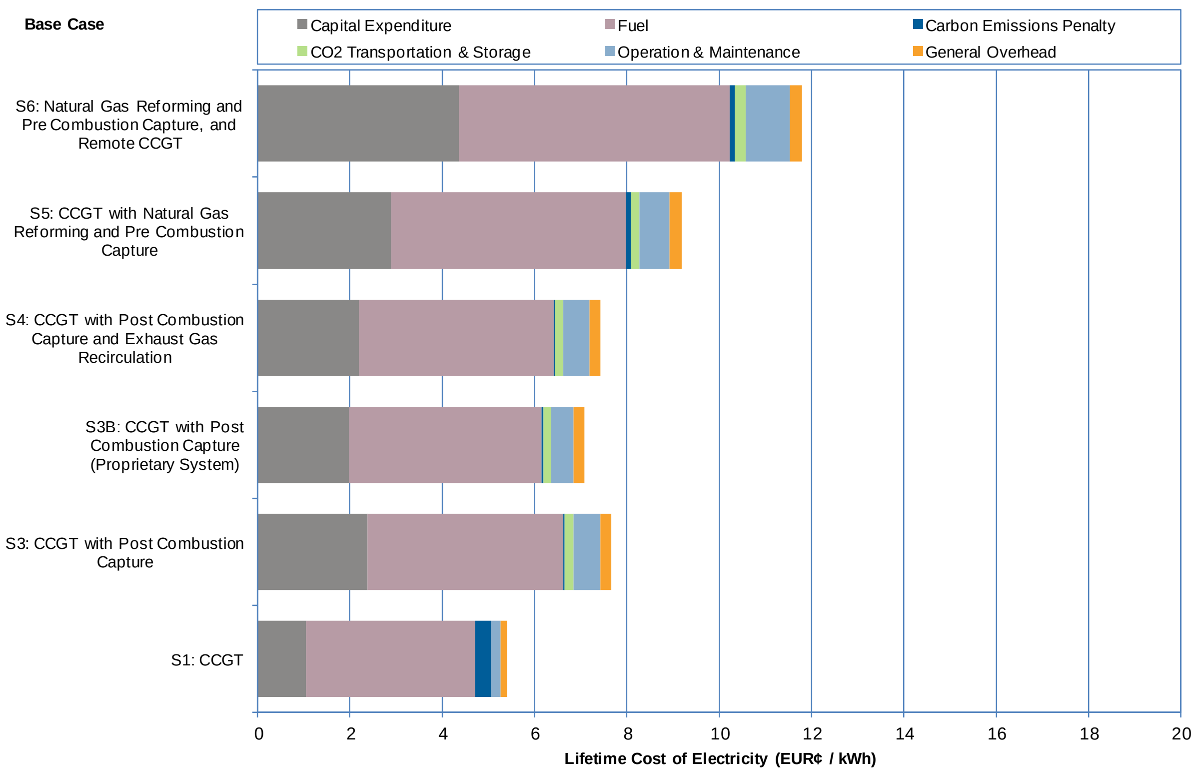


Figure 23 Comparison of the Lifetime Costs of Electricity (EUR¢ per kWh) - Base Case

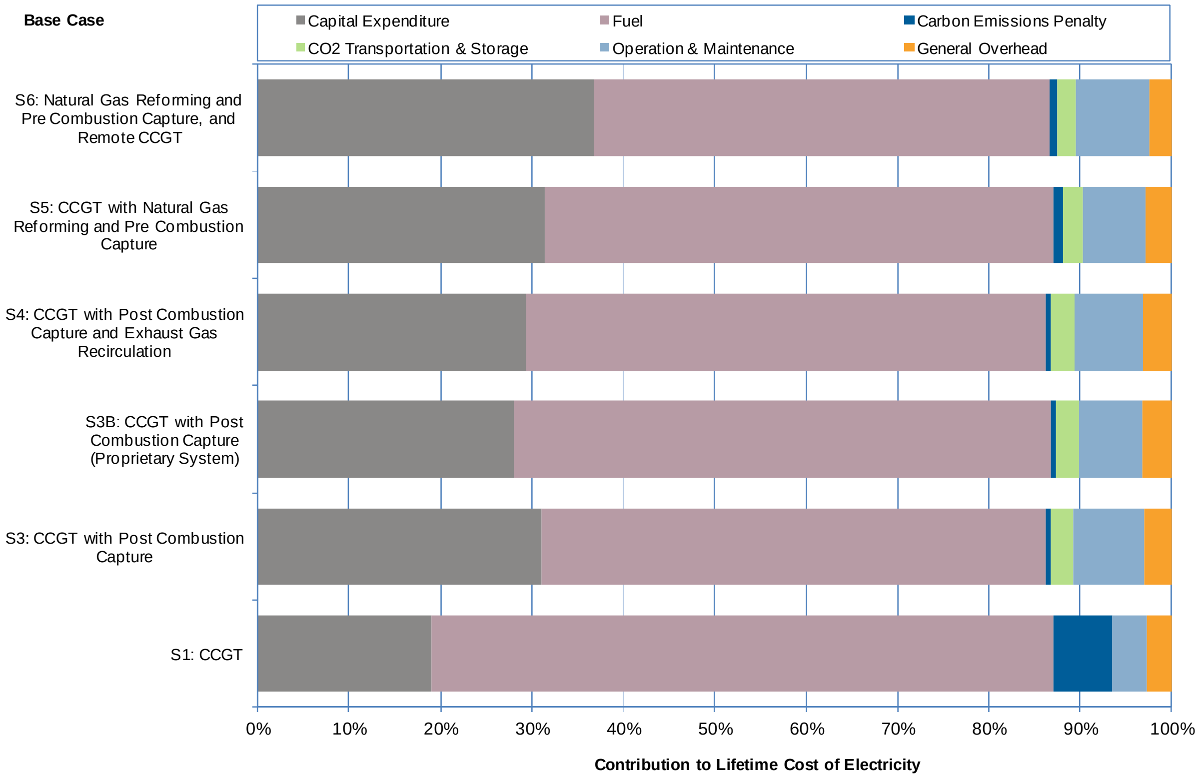


Figure 24 Contribution to the Lifetime Costs of Electricity (%) - Base Case

It is apparent from the graphs above that the scenarios are ranked (in terms of lowest total lifetime cost of generation) as follows:

1. Scenario 1 – Reference CCGT Plant;
2. Scenario 3b - CCGT with Post Combustion Capture (utilising a typical Propriety System);
3. Scenario 4 - CCGT with Post Combustion Capture (35%wt MEA) and FGR;
4. Scenario 3 - CCGT with Post Combustion Capture (35%wt MEA);
5. Scenario 5 - CCGT with Natural Gas Reforming and Pre Combustion Capture; and
6. Scenario 6 - Natural Gas Reforming and Pre Combustion Capture with Remote CCGT.

10.5 Sensitivity Analysis

A series of sensitivities have been developed to analyse the impact of changes to key input assumptions on the total lifetime cost of generation and the relative competitiveness of the scenarios under consideration. The sensitivities analysed are:

- Changes to the gas price;

- Changes to the Carbon Emissions Penalty;
- Changes to the cost of CO_2 transportation and storage;
- Changes to the discount rate; and
- Changes to the capacity factor of the plant.

The results of the sensitivity analysis are detailed in the sub-sections below. Summary graphs which show the impacts of all sensitivities on the lifetime costs of electricity generation for each scenario are presented in Appendix G.

10.5.1 Changes to the Gas Price

This sensitivity analyses the impact of changes to the assumed gas price on the lifetime cost of generation. This analysis has been undertaken using a low gas price of EUR 3 per GJ $_{LHV}$ and a high gas price of EUR 12 per GJ $_{LHV}$. The lifetime costs of generation for the low and high gas price sensitivities are presented in Table 48 and Table 49.

Table 48 Lifetime Cost of Electricity (EUR¢ per kWh) - Low Gas Price

Low Gas Price	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.01	1.83	0.35	0.00	0.20	0.14	3.54
S3: CCGT with Post Combustion Capture	2.36	2.12	0.04	0.18	0.59	0.23	5.52
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.96	2.08	0.04	0.18	0.48	0.23	4.97
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.16	2.10	0.04	0.18	0.56	0.23	5.28
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.85	2.55	0.09	0.20	0.63	0.26	6.59
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.32	2.94	0.10	0.23	0.96	0.28	8.83

Table 49 Lifetime Cost of Electricity (EUR¢ per kWh) - High Gas Price

High Gas Price	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.06	7.34	0.35	0.00	0.20	0.14	9.09
S3: CCGT with Post Combustion Capture	2.41	8.46	0.04	0.18	0.59	0.23	11.93
S3B: CCGT with Post Combustion Capture (Proprietary System)	2.02	8.31	0.04	0.18	0.48	0.23	11.26
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.22	8.42	0.04	0.18	0.56	0.23	11.65
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.93	10.21	0.09	0.20	0.63	0.26	14.32
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.40	11.75	0.10	0.23	0.96	0.28	17.73

A decrease in the gas price to 50% (i.e. half) reduces the lifetime cost of all scenarios. Scenario 1 has a total lifetime cost of EUR¢ 3.54 per kWh, whilst Post Combustion Capture plant options (Scenarios 3, 3b and 4) have a total lifetime cost of around EUR¢ 4.97 – 5.52 per kWh. The total lifetime cost of Scenarios 5 and 6 are EUR¢ 6.59 per kWh and EUR¢ 8.83 per kWh respectively.

An increase in the gas price to 200% (i.e. double) increases the lifetime cost of all scenarios. Scenario 1 has a total lifetime cost of EUR¢ 9.09 per kWh, whilst Scenarios 3, 3b and 4 have a total lifetime cost of EUR¢ 11.93 per kWh, EUR¢ 11.26 per kWh and EUR¢ 11.65 per kWh respectively. The total lifetime cost of Scenarios 5 and 6 are EUR¢ 14.32 per kWh and EUR¢ 17.73 per kWh respectively.

It is apparent from this analysis that the total lifetime cost of generation of all scenarios are highly sensitive to a change in gas price, although the ranking of alternatives does not change from the ranking determined under base case assumptions. This is a result of the plant efficiencies and the respective fuel consumption characteristics.

Whilst the impact of a change in the gas price impacts the fuel component of the lifetime costs calculation, it should be noted that changes in the fuel price also have a small impact on the cost of capital expenditure. This variation in cost arises because the derivation of the cost of capital expenditure includes a start-up cost associated with fuel and therefore if the fuel price increases or decreases in relation to the base case assumption then the amount of start up capital to cover the cost of fuel will alter.

The lifetime costs of electricity generation for each scenario under low and high gas price sensitivities are presented graphically in Figure 25 and Figure 26.

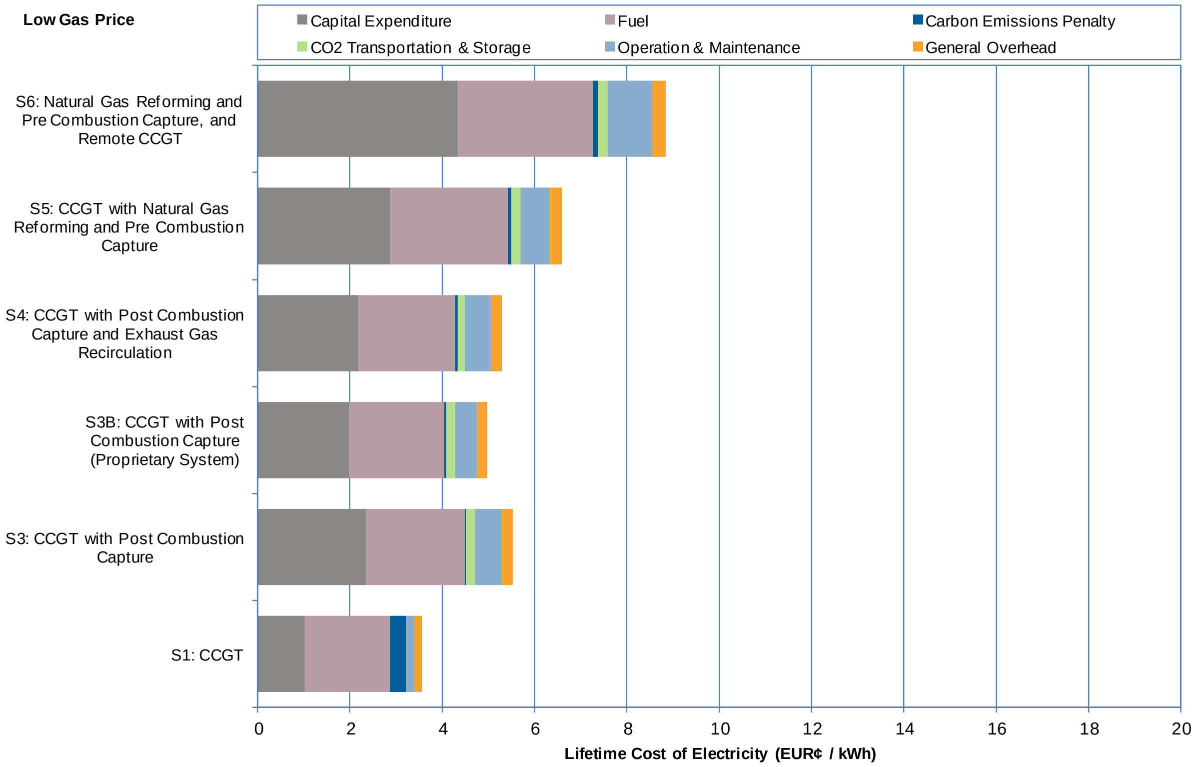


Figure 25 Lifetime Cost of Electricity (EUR¢ per kWh) - Low Gas Price

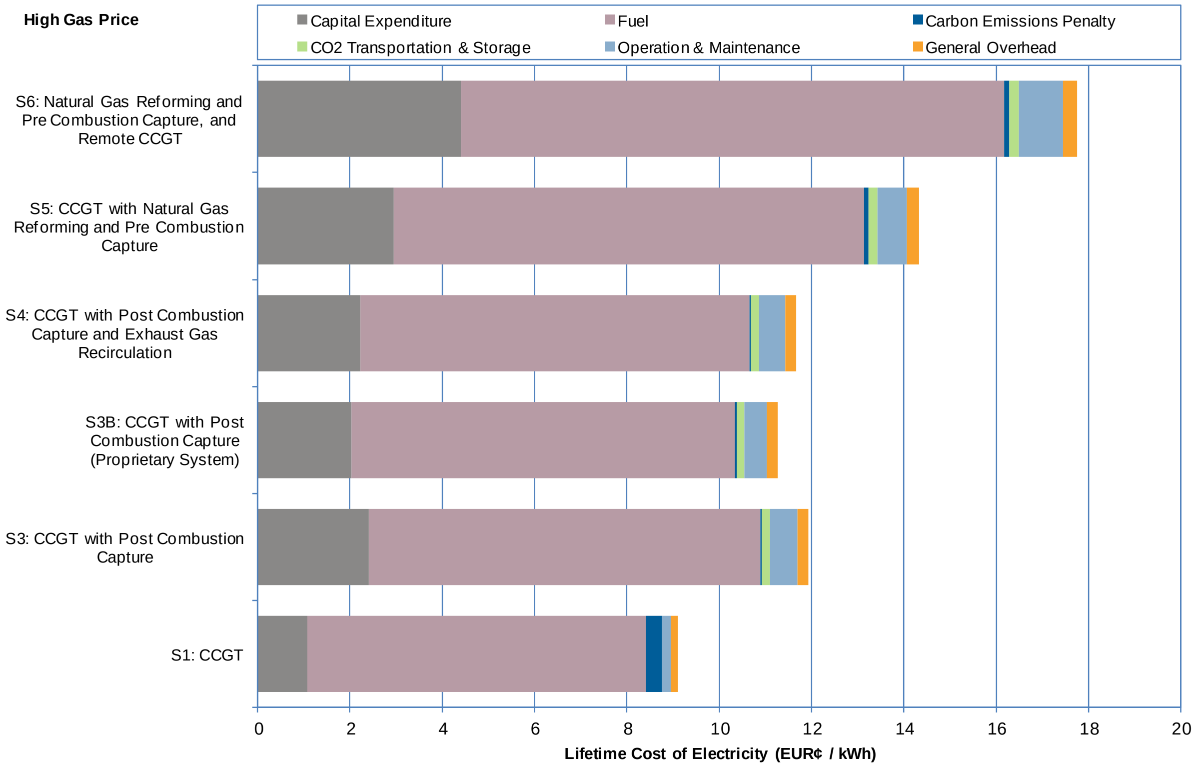


Figure 26 Lifetime Cost of Electricity (EUR¢ per kWh) - High Gas Price

10.5.2 Changes to the Carbon Emissions Penalty

This sensitivity analyses the impact of changes to the Carbon Emissions Penalty on the lifetime cost of generation. This analysis has been undertaken using three different Carbon Emission Penalty prices:

- a Carbon Emissions Penalty of EUR 0 per tonne of CO_2 emitted;
- a Carbon Emissions Penalty of EUR 50 per tonne of CO_2 emitted; and
- a Carbon Emissions Penalty of EUR 100 per tonne of CO_2 emitted

The lifetime cost of electricity for the EUR 0 per tonne, EUR 50 per tonne and EUR 100 per tonne sensitivities are presented in Table 50, Table 51, and Table 52.

Table 50 Lifetime Cost of Electricity (EUR¢ per kWh) - EUR 0 per tonne Carbon Emissions Penalty

EUR 0 per tonne Carbon Emissions Penalty	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.03	3.67	0.00	0.00	0.20	0.14	5.05
S3: CCGT with Post Combustion Capture	2.38	4.23	0.00	0.18	0.59	0.23	7.62
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.98	4.16	0.00	0.18	0.48	0.23	7.03
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.18	4.21	0.00	0.18	0.56	0.23	7.37
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.88	5.11	0.00	0.20	0.63	0.26	9.08
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.35	5.88	0.00	0.23	0.96	0.28	11.70

Table 51 Lifetime Cost of Electricity (EUR¢ per kWh) - EUR 50 per tonne Carbon Emissions Penalty

EUR 50 per tonne Carbon Emissions Penalty	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.03	3.67	1.74	0.00	0.20	0.14	6.79
S3: CCGT with Post Combustion Capture	2.38	4.23	0.20	0.18	0.59	0.23	7.82
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.98	4.16	0.20	0.18	0.48	0.23	7.23
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.18	4.21	0.20	0.18	0.56	0.23	7.57
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.88	5.11	0.45	0.20	0.63	0.26	9.52
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.35	5.88	0.52	0.23	0.96	0.28	12.21

Table 52 Lifetime Cost of Electricity (EUR¢ per kWh) - EUR 100 per tonne Carbon Emissions Penalty

EUR 100 per tonne Carbon Emissions Penalty	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.03	3.67	3.48	0.00	0.20	0.14	8.53
S3: CCGT with Post Combustion Capture	2.38	4.23	0.41	0.18	0.59	0.23	8.03
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.98	4.16	0.40	0.18	0.48	0.23	7.43
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.18	4.21	0.41	0.18	0.56	0.23	7.77
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.88	5.11	0.89	0.20	0.63	0.26	9.97
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.35	5.88	1.04	0.23	0.96	0.28	12.73

As Scenario 1 has the highest level of CO_2 emissions per kWh, it gains the largest benefit from the absence of the Carbon Emissions Penalty, reducing the total lifetime cost of electricity by EUR¢ 0.34 per kWh to EUR¢ 5.05 per KWh. Due to the lower level of emissions, the lifetime cost of the carbon capture plant options achieve smaller reductions in their total lifetime cost. This means that in the absence of a Carbon Emissions Penalty, Scenario 1 becomes more attractive relative to the other scenarios when compared to the base case.

This notion is reversed in the scenario where the Carbon Emissions Penalty is increased from the base case price to EUR 50 per tonne of CO_2 emitted. The lifetime cost results from this sensitivity indicate that impact upon the lifetime cost of Scenario 1 is greater than those scenarios where carbon capture technology is present. This hypothesis is confirmed through analysis of the EUR 100 per tonne of CO_2 emitted sensitivity at which point Scenario 1 is no longer the least cost Scenario and the lifetime costs of Scenarios 3, 3b and 4 are all lower than the lifetime cost of Scenario 1.

Analysis to determine the Carbon Emissions Penalty breakeven point (the point at which the lifetime cost of electricity generation of Scenarios 3, 3b, 4, 5 and 6 becomes equal to or lower than the lifetime cost of electricity generation of Scenario 1) has been undertaken and results are presented in Table 53;

Table 53 Carbon Emissions Penalty Breakeven point, and associated Lifetime Cost of Electricity

	Carbon Emissions Penalty breakeven point	
	Carbon Emissions Penalty (EUR per tonne)	Total Lifetime Cost of Generation (EUR¢ per kWh)
Scenario 1	-	-
Scenario 3	89.75	7.96
Scenario 3B	64.50	7.29
Scenario 4	75.50	7.67
Scenario 5	155.75	10.47
Scenario 6	271.75	14.51

It is apparent from this analysis that the total lifetime cost of generation of Scenario 1 is more sensitive to changes in the carbon emissions penalty than those scenarios with carbon capture technology fitted.

The lifetime costs for each of the Carbon Emissions Penalty sensitivities are presented graphically in Figure 27, Figure 28, and Figure 29.

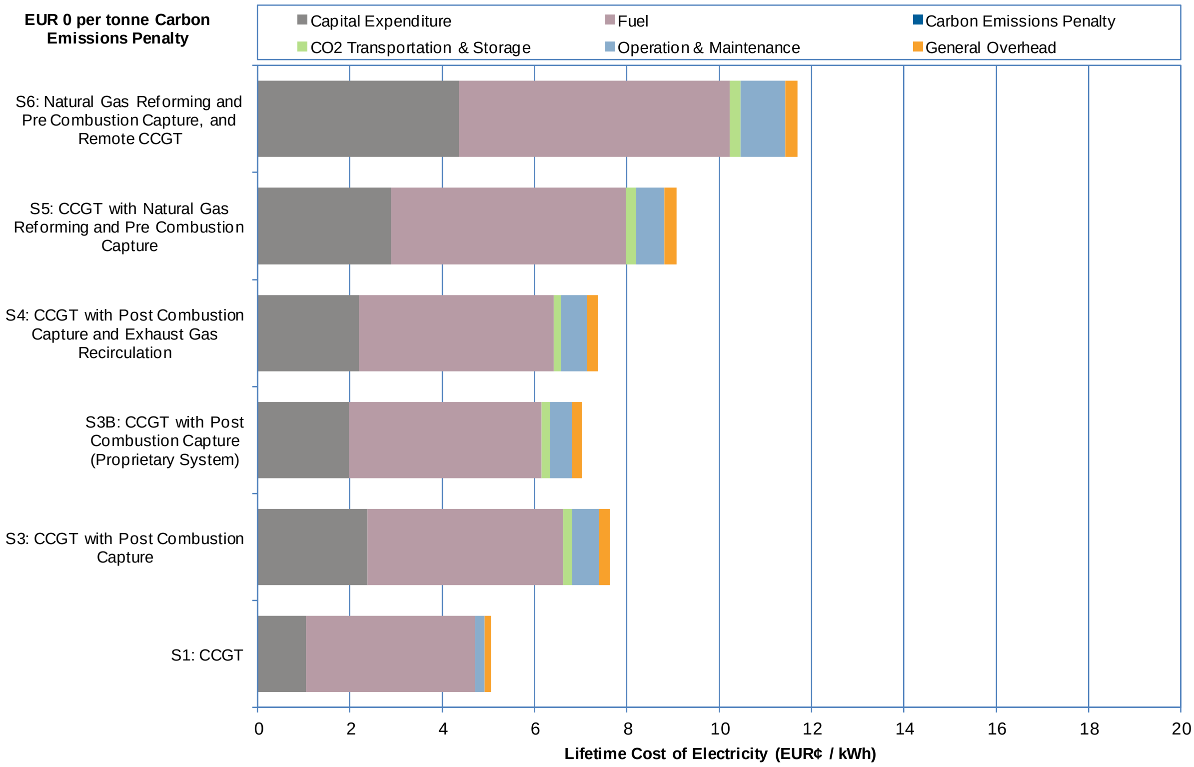


Figure 27 Lifetime Cost of Electricity (EUR¢ per kWh) - EUR 0 per tonne Carbon Emissions Penalty

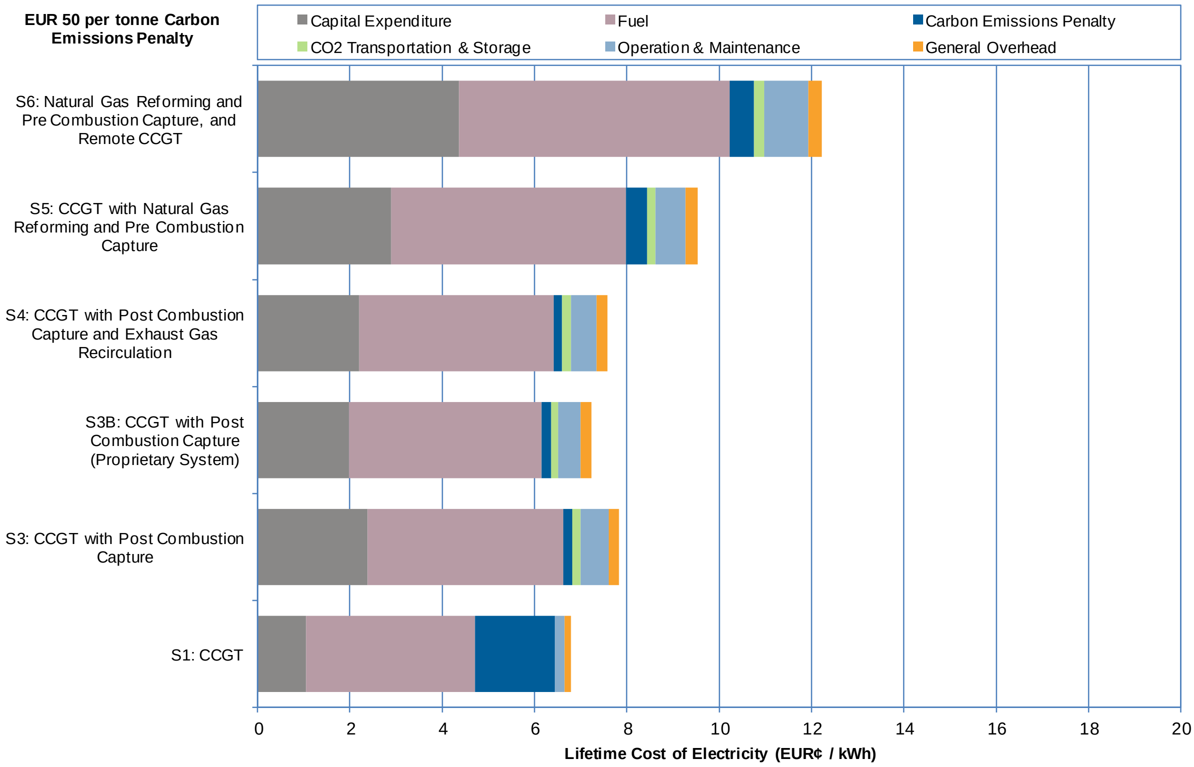


Figure 28 Lifetime Cost of Electricity (EUR¢ per kWh) - EUR 50 per tonne Carbon Emissions Penalty

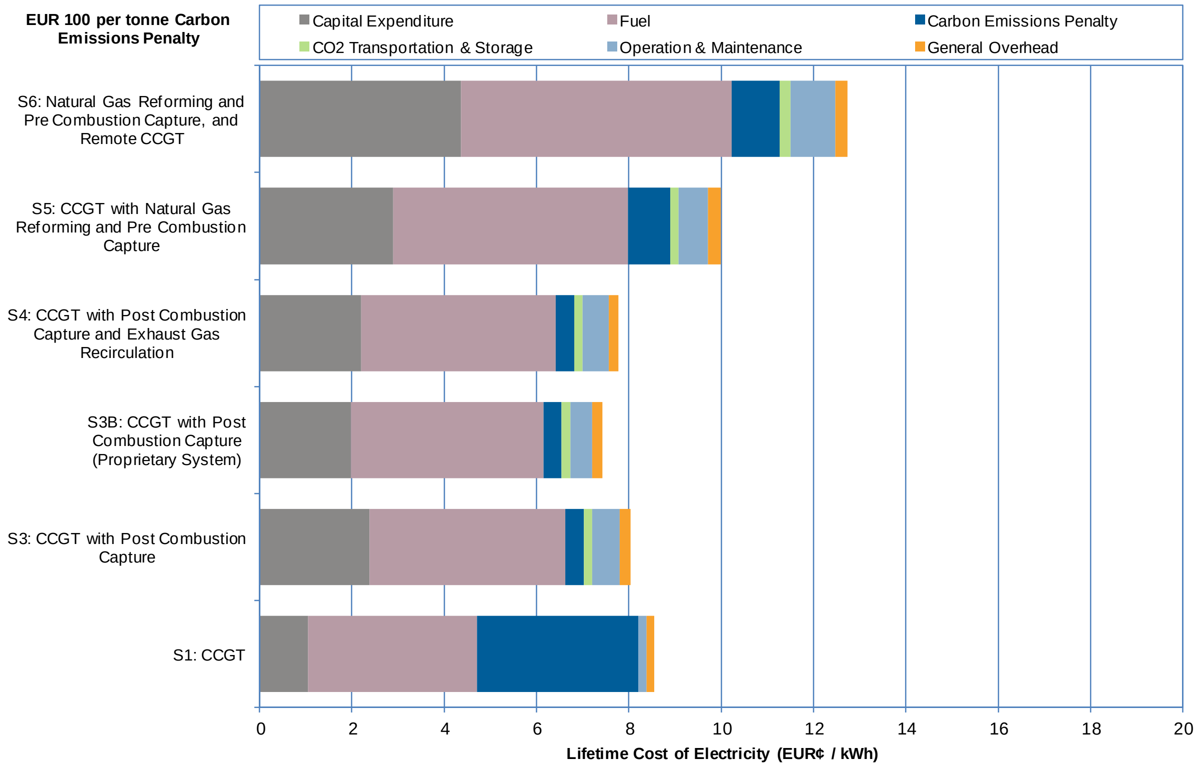


Figure 29 Lifetime Cost of Electricity (EUR¢ per kWh) - EUR 100 per tonne Carbon Emissions Penalty

10.5.3 Changes to the Cost of CO_2 Transportation and Storage

This sensitivity analyses the impact of changes to the cost of CO_2 transportation and storage on the lifetime cost of generation. This analysis has been undertaken to determine the impact on the lifetime cost if there were no charge for CO_2 transportation and storage (for example where captured CO_2 can be sold for reuse) and if there were a high charge for CO_2 transportation and storage of EUR 10 per tonne of CO_2 stored. The lifetime cost of generation for the zero and high cost of CO_2 transportation and storage sensitivities are presented in Table 54 and Table 55.

Table 54 Lifetime Cost of Electricity (EUR¢ per kWh) – Zero CO_2 Transportation and Storage Cost

Zero C02 Transportation & Storage Cost	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.03	3.67	0.35	0.00	0.20	0.14	5.39
S3: CCGT with Post Combustion Capture	2.38	4.23	0.04	0.00	0.59	0.23	7.48
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.98	4.16	0.04	0.00	0.48	0.23	6.89
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.18	4.21	0.04	0.00	0.56	0.23	7.23
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.88	5.11	0.09	0.00	0.63	0.26	8.97
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.35	5.88	0.10	0.00	0.96	0.28	11.57

Table 55 Lifetime Cost of Electricity (EUR¢ per kWh) - High CO_2 Transportation and Storage Cost

High C02 Transportation & Storage Cost	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.03	3.67	0.35	0.00	0.20	0.14	5.39
S3: CCGT with Post Combustion Capture	2.38	4.23	0.04	0.37	0.59	0.23	7.84
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.98	4.16	0.04	0.36	0.48	0.23	7.25
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.18	4.21	0.04	0.36	0.56	0.23	7.59
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.88	5.11	0.09	0.40	0.63	0.26	9.36
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	4.35	5.88	0.10	0.45	0.96	0.28	12.03

Changes in the cost of CO_2 transportation and storage have no impact on the total lifetime cost of Scenario 1 as this option does not have any carbon storage facilities. Changes in the cost of CO_2 transportation and storage does, however, have an impact on the relative competitiveness of those scenarios with carbon capture facilities, when compared to plant Scenario 1.

In the sensitivity where the cost of CO_2 transportation and storage is reduced to zero, all of the carbon capture plant options become more competitive with Scenario 1. Scenario 6 has the largest reduction in total lifetime costs, making it more competitive with the other carbon capture technologies (although it is still the most expensive option by some distance). In the sensitivity where the cost of CO_2 transportation and storage is increased above the base case price (to EUR 10 per tonne of CO_2 stored) the opposite occurs. In this sensitivity, Scenario 6 has the highest increase in total lifetime costs (as it captures the most CO_2), making it less competitive with the other carbon capture technologies, whilst all of the carbon capture plant options become less competitive with Scenario 1.

It should be noted, that the changes in lifetime cost accrued from changes in the cost of CO_2 transportation and storage in this study are minimal relative to the total lifetime costs of the plant options.

The lifetime costs for the zero and high costs of CO_2 transportation and storage are presented graphically in Figure 30, and Figure 31.

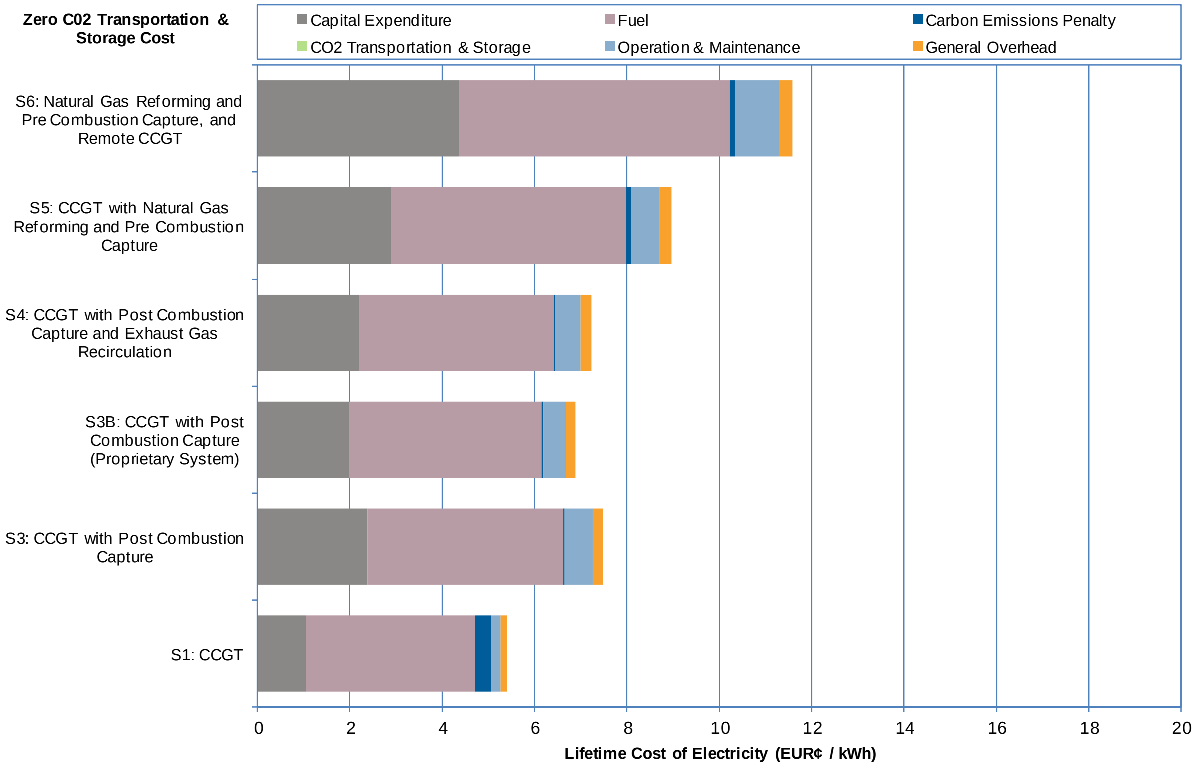


Figure 30 Lifetime Cost of Electricity (EUR¢ per kWh) - Zero CO_2 Transportation and Storage Cost

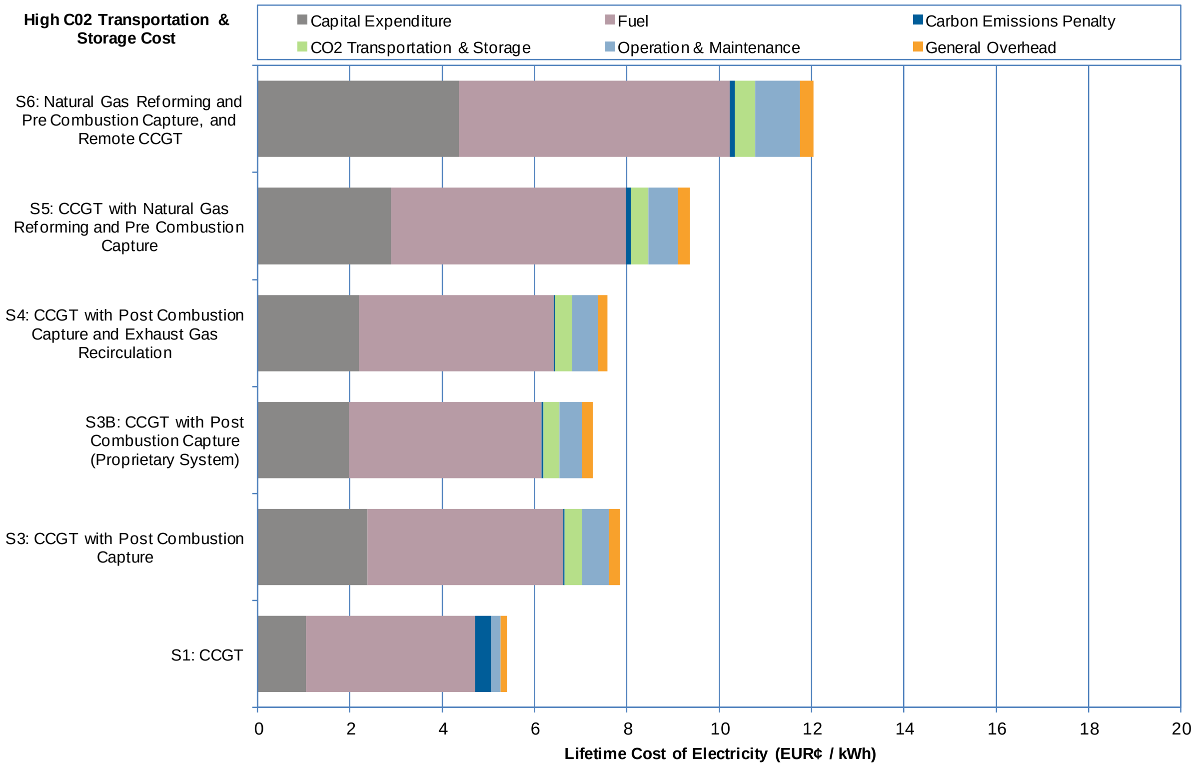


Figure 31 Lifetime Cost of Electricity (EUR¢ per kWh) - High CO_2 Transportation and Storage Cost

10.5.4 Changes to the Discount Rate

This sensitivity analyses the impact of changes to the discount rate on the lifetime cost of generation. This analysis has been undertaken using a low discount rate of 5% and a high discount rate of 10%. The lifetime cost of generation for the low and high discount rate sensitivities are presented in Table 56 and Table 57.

Table 56 Lifetime Cost of Electricity (EUR¢ per kWh) - Low Discount Rate

Low Discount Rate	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	0.72	3.67	0.35	0.00	0.20	0.14	5.09
S3: CCGT with Post Combustion Capture	1.65	4.23	0.04	0.18	0.59	0.23	6.93
S3B: CCGT with Post Combustion Capture (Proprietary System)	1.38	4.16	0.04	0.18	0.48	0.23	6.46
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	1.52	4.21	0.04	0.18	0.56	0.23	6.74
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	2.00	5.11	0.09	0.20	0.63	0.26	8.29
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	3.03	5.88	0.10	0.23	0.96	0.28	10.47

Table 57 Lifetime Cost of Electricity (EUR¢ per kWh) - High Discount Rate

High Discount Rate	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.27	3.67	0.35	0.00	0.20	0.14	5.64
S3: CCGT with Post Combustion Capture	2.96	4.23	0.04	0.18	0.60	0.23	8.24
S3B: CCGT with Post Combustion Capture (Proprietary System)	2.46	4.16	0.04	0.18	0.48	0.23	7.55
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	2.71	4.21	0.04	0.18	0.56	0.23	7.94
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	3.58	5.11	0.09	0.20	0.63	0.26	9.87
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	5.40	5.88	0.10	0.23	0.96	0.29	12.86

A change in the discount rate impacts on the cost of capital expenditure only. At a lower discount rate, the lifetime cost of capital expenditure for all scenarios reduces. Due to the identical capital disbursement schedules assumed for all scenarios, the lower discount rate sensitivity reduces the lifetime cost of capital expenditure at a greater rate on those plants with higher capital costs and thus this sensitivity sees the higher capital cost scenarios increasing their competitiveness relative to smaller capital cost scenarios.

This notion is reversed when the discount rate is increased. At a higher discount rate, the lifetime cost of capital expenditure for all scenarios increases. Again, due to the identical capital disbursement schedules assumed for all scenarios, the higher discount rate increases the lifetime cost of capital expenditure at a greater rate for those plants with high capital costs and thus this sensitivity sees the lower capital cost scenarios increasing their competitiveness relative to the higher capital cost scenarios.

It should be noted that the changes to the discount rate considered as part of this study do not materially change the conclusions from the base case scenario, such that the ranking of projects on the basis of total lifetime cost remains unchanged.

The lifetime costs for each scenario under the low and high discount rate sensitivities are presented graphically in Figure 32 and Figure 33.

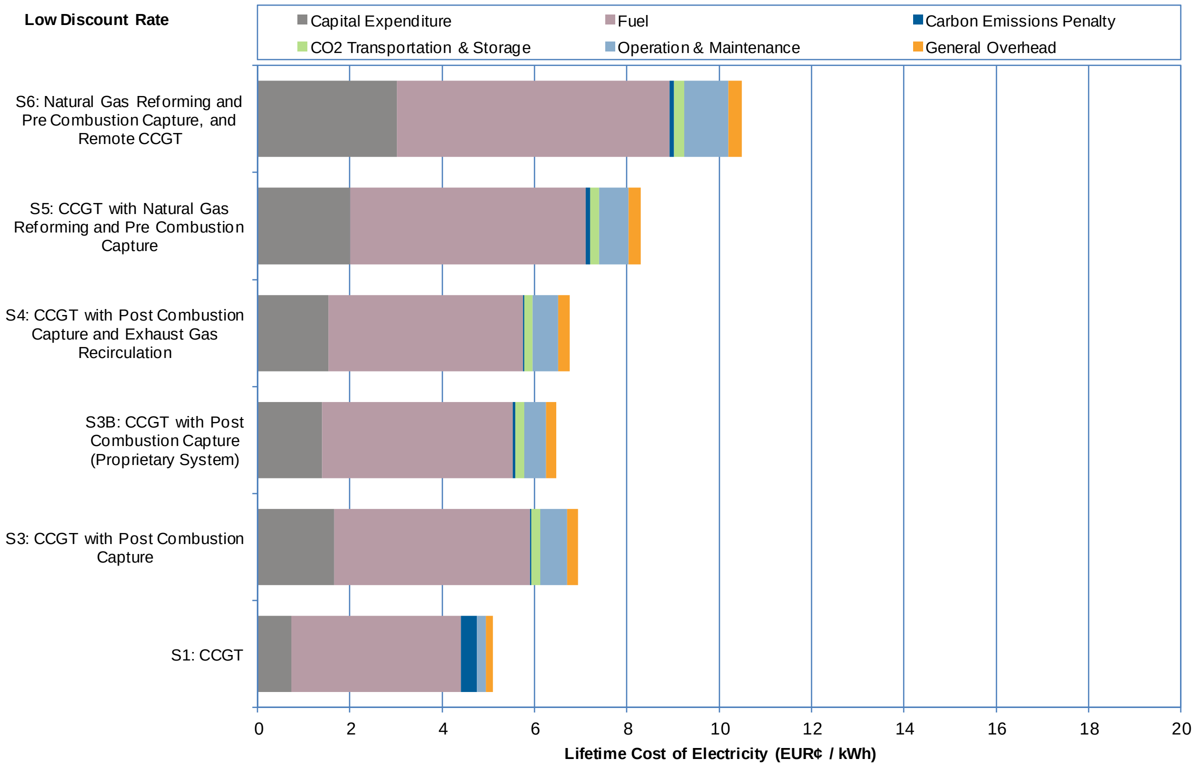


Figure 32 Lifetime Cost of Electricity (EUR¢ per kWh) - Low Discount Rate

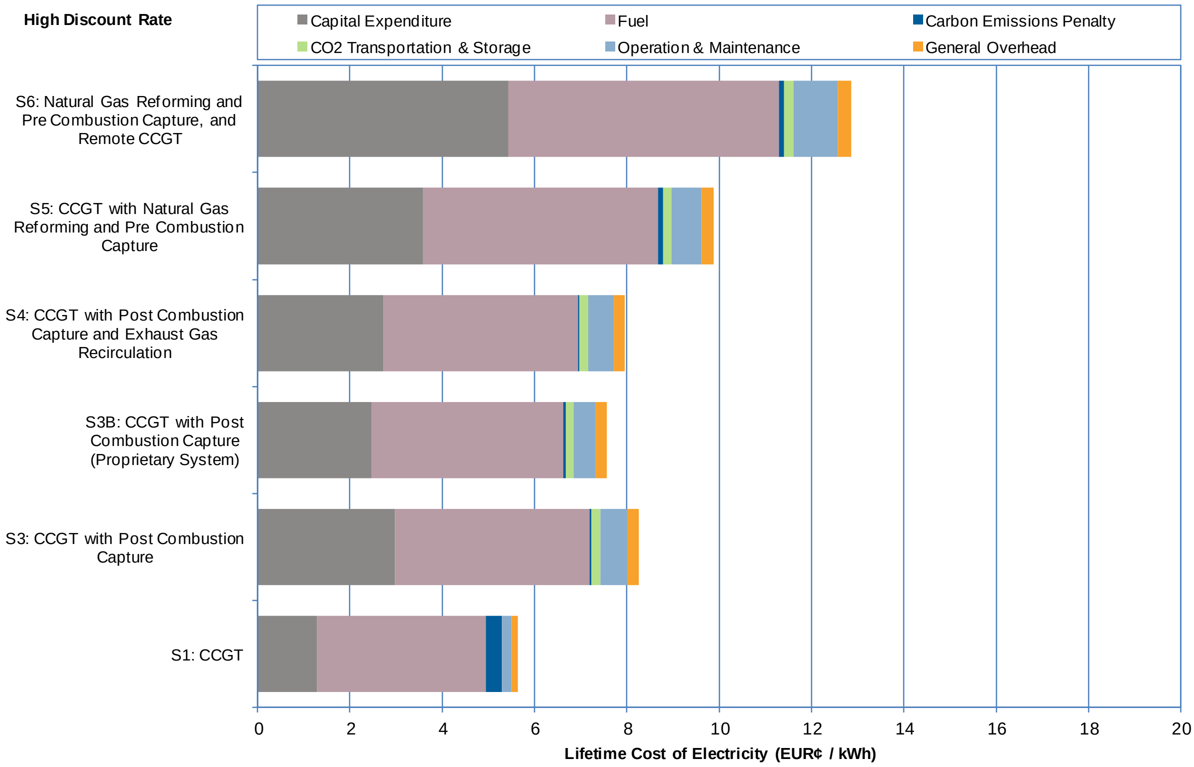


Figure 33 Lifetime Cost of Electricity (EUR¢ per kWh) - High Discount Rate

10.5.5 Changes to the Capacity Factor

It is noted that flexible operation is a key benefit of gas-fired power plants, and so this sensitivity analyses the impact of changes to the operating capacity factor of the plants on the lifetime cost of generation. This analysis has been undertaken using a 50% capacity factor and a 25% capacity factor. The lifetime cost of generation for the 50% and 25% capacity factor sensitivities are presented in Table 58 and Table 59.

Table 58 Lifetime Cost of Electricity (EUR¢ per kWh) – 50% Capacity Factor

50% Capacity Factor	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	1.91	3.67	0.35	0.00	0.31	0.27	6.51
S3: CCGT with Post Combustion Capture	4.15	4.23	0.04	0.18	0.80	0.41	9.81
S3B: CCGT with Post Combustion Capture (Proprietary System)	3.46	4.16	0.04	0.18	0.65	0.40	8.89
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	3.82	4.21	0.04	0.18	0.74	0.41	9.40
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	4.77	5.11	0.09	0.20	0.85	0.43	11.44
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	7.20	5.88	0.10	0.23	1.28	0.47	15.16

Table 59 Lifetime Cost of Electricity (EUR¢ per kWh) – 25% Capacity Factor

25% Capacity Factor	Capital Expenditure	Fuel	Carbon Emissions Penalty	CO2 Transportation & Storage	Operation & Maintenance	General Overhead	Total Lifetime Cost
S1: CCGT	3.82	3.67	0.35	0.00	0.55	0.54	8.92
S3: CCGT with Post Combustion Capture	8.31	4.23	0.04	0.18	1.27	0.81	14.84
S3B: CCGT with Post Combustion Capture (Proprietary System)	6.93	4.16	0.04	0.18	1.04	0.81	13.15
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	7.63	4.21	0.04	0.18	1.18	0.81	14.05
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	9.54	5.11	0.09	0.20	1.38	0.87	17.18
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	14.40	5.88	0.10	0.23	2.10	0.94	23.65

A change in the capacity factor alters the number of hours a plant will operate over the year. Whilst this change will alter the spend on O&M and general overheads (as these costs are typically based on the number of fired hours a plant operates), the overall impact of a change in these cost streams on the lifetime cost of generation will be minimal.

Altering the number of hours that a plant operates does, however, have a significant impact on the lifetime cost contribution of capital expenditure and the total lifetime cost of generation. The lifetime cost of generation (calculated in EUR per kWh) is determined by dividing all costs by the amount of electricity generated over the lifetime of the plant. The more the plant is operated, the greater the total number of hours over which the capital costs can be recouped. Resultantly, the lifetime cost contribution of capital expenditure can vary greatly to changes in the capacity factor.

In this sensitivity the lifetime cost of electricity generation is determined at lower capacity factors than those assumed in the base case analysis. Lowering the capacity factor increases the lifetime cost contribution of capital expenditure as the capital expenditure of the plant remains constant but the total amount of generation from the plant reduces. This trend is greater for plants with higher capital costs and therefore it can be summarised that, as the capacity factor decreases, those scenarios with higher plant capital costs become less competitive against those plants with lower capital costs.

It should be noted that the changes to the capacity factor considered as part of this study significantly change the total lifetime costs of the scenarios under consideration, although the ranking of alternatives does not change.

The lifetime costs for each scenario under the 50% and 25% capacity factor sensitivities are presented graphically in Figure 34 and Figure 35.

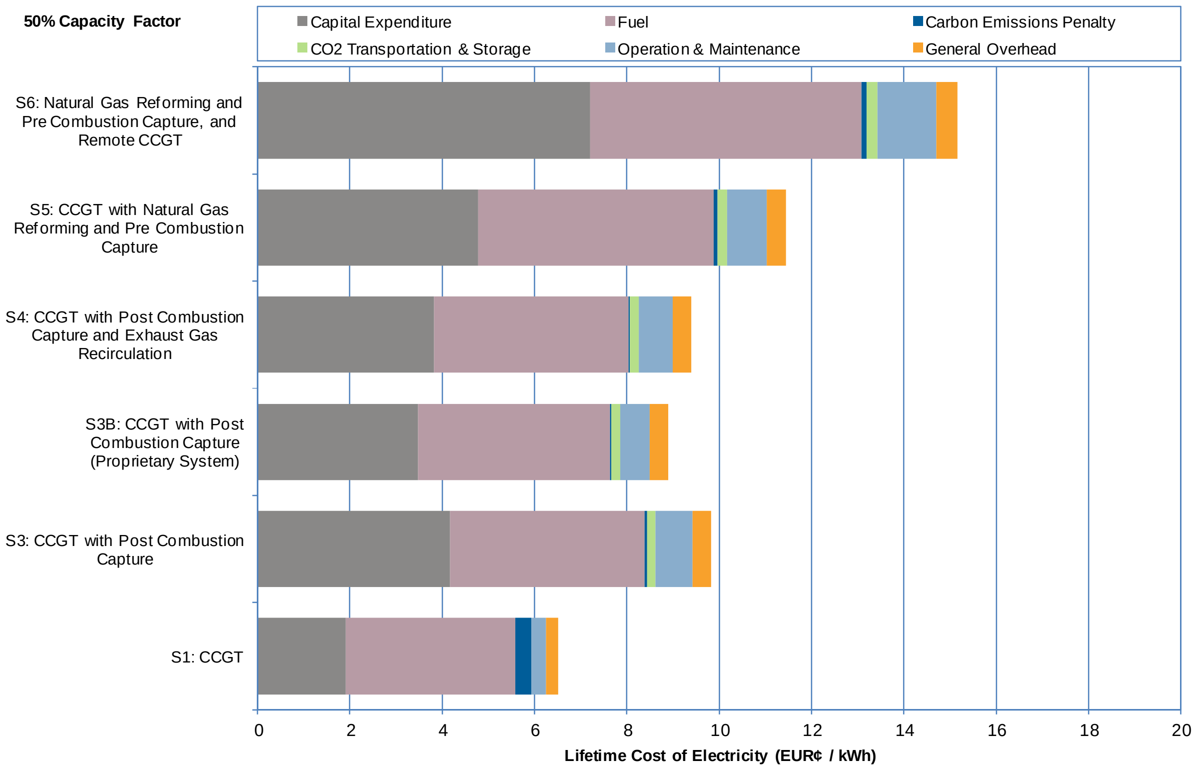


Figure 34 Lifetime Cost of Electricity (EUR¢ per kWh) - 50% Capacity Factor

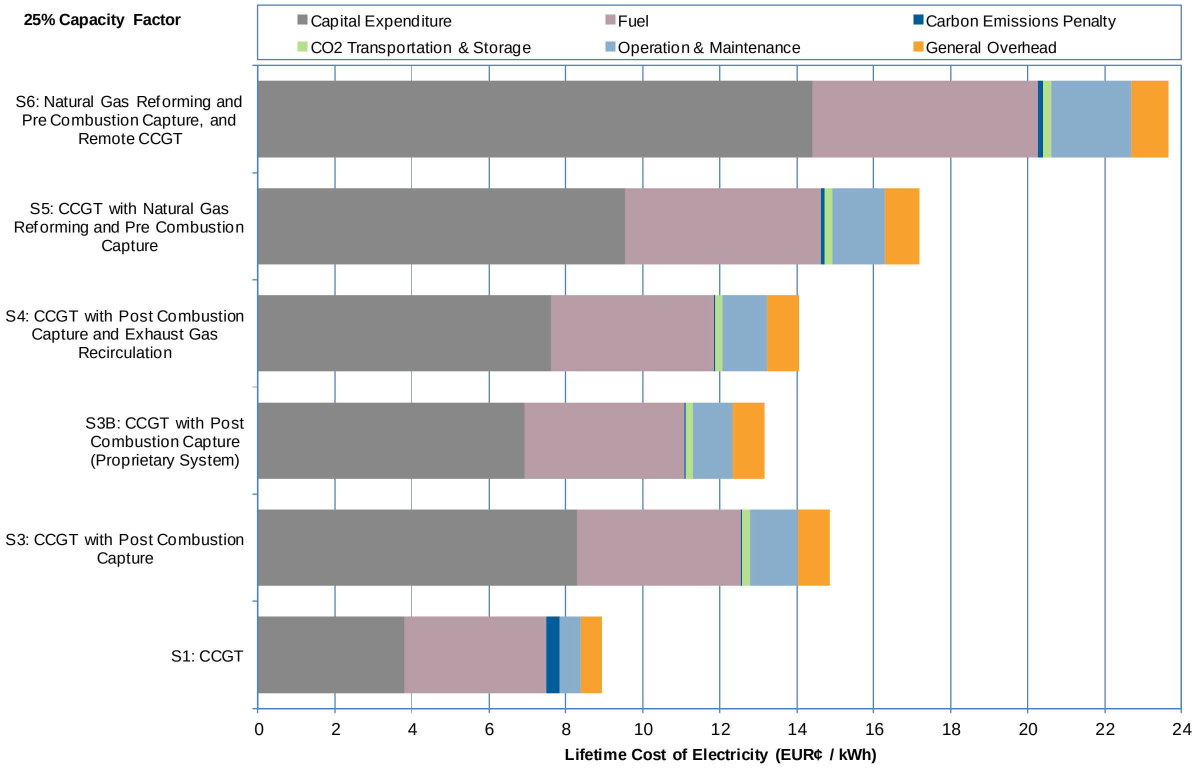


Figure 35 Lifetime Cost of Electricity (EUR¢ per kWh) – 25% Capacity Factor

Scenario 6 merits special mention with respect to the capacity factor sensitivities presented above. Based on the results it is clear that the CAPEX requirements of the reformer plant and storage site make this Scenario uncompetitive in a 1:1 configuration, particularly at lower capacity factors.

It is proposed that the benefits of natural gas reforming and hydrogen storage are more fully realised in a configuration where a reforming plant and storage capacity are shared between more than one CCGT. In such a configuration the dedicated reforming plant would operate at base-load (thereby ensuring optimal efficiency) while the CCGT plant operates flexibly. CAPEX requirements for the reforming plant and storage site would be shared across the CCGT's and as such the relative contribution of reforming / storage CAPEX to the levelised cost of generation would be reduced from that which is presented in these results. This configuration would have the potential to reduce specific costs (EUR/kW) for low load plants. While it is out-with the scope of this study, it is concluded that further analysis of this subject is merited.

10.6 Conclusions from economic modelling

Under base case assumptions, the modelling of the lifetime cost of generation carried out for this study indicates that in terms of lowest total lifetime cost, Scenario 1 is the preferred option. This conclusion does not however, highlight some of the other pertinent points that can be drawn from the analysis undertaken.

10.6.1 Base Case Conclusions

The key conclusions from the base case modelling analysis are as follows:

- The scenarios are ranked (by lowest total lifetime cost of generation), as follows:

    1. Scenario 1 (EUR 5.39 per kWh)
    2. Scenario 3b (EUR 7.07 per kWh or 31% higher than Scenario 1)
    3. Scenario 4 (EUR 7.41 per kWh or 37% higher than Scenario 1)
    4. Scenario 3 (EUR 7.66 per kWh or 42% higher than Scenario 1)
    5. Scenario 5 (EUR 9.17 per kWh or 70% higher than Scenario 1)
    6. Scenario 6 (EUR 11.80 per kWh or 119% higher than Scenario 1)

- In all scenarios, fuel is the largest contributor to the lifetime cost of generation (accounting for around 50 - 68% of the total lifetime cost). The cost per kWh associated with fuel is higher for those scenarios with carbon capture technology fitted due to lower plant efficiencies (and thus the need to burn more fuel to produce the same amount of energy). It should be noted however, that as a percentage of the total lifetime cost of generation, fuel actually accounts for a smaller proportion of the total lifetime cost in those scenarios with lower efficiencies. This is in large part due to the additional capital costs associated with carbon capture technologies when compared to typical CCGT plants.

- Capital expenditure is the second largest contributor to the lifetime cost of generation (accounting for around 19 - 37% of the total lifetime cost). Logically, the cost per kWh associated with capital expenditure is higher for those scenarios with carbon capture technology fitted. This is because of the higher capital costs associated with implementing these technologies on plants with the same/similar net power output. The proportion contribution to the total lifetime cost is greater for Pre Combustion Capture plant (around 31 – 37%) than for Post Combustion Plant (28 – 31%) when compared to a typical CCGT plant (19%).

- The cost of O&M and general overheads is greater in those scenarios with carbon capture and storage facilities (ranging from around 9.8 – 10.7% of the total lifetime cost of generation) than in the typical CCGT scenario (6.4% of the total lifetime cost of generation).

- The typical CCGT plant (Scenario 1) does not have any carbon capture facilities and as such will emit more CO_2 per kWh of generation than those plant options that do have carbon capture facilities. These emissions incur a charge (Carbon Emissions Penalty) and will therefore impact the lifetime cost of generation for a typical CCGT plant to a greater extent than for those plant with carbon capture facilities and thus lower CO_2 emissions. Conversely however, those plant with carbon capture facilities must pay additional costs for the safe and secure transportation and storage of the CO_2 captured. Therefore any benefit derived from lower Carbon Emission Penalty payments will be (to some extent) offset by the costs of transportation and storage.

- Analysis of the cost of carbon (cost of emissions plus the cost of CO_2 transportation and storage) is presented in Table 60;

Table 60 Cost of CO_2 emissions, storage and transportation (Base Case, EUR per kWh)

Base Case	Carbon Emissions Penalty	CO2 Transportation & Storage	Total Carbon Lifetime Cost	Total Lifetime Cost
S1: CCGT	0.35	0.00	0.35	5.39
S3: CCGT with Post Combustion Capture	0.04	0.18	0.22	7.66
S3B: CCGT with Post Combustion Capture (Proprietary System)	0.04	0.18	0.22	7.07
S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	0.04	0.18	0.22	7.41
S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	0.09	0.20	0.29	9.17
S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT	0.10	0.23	0.33	11.80

- At the base case Carbon Emission Penalty price (EUR 10 per tonne of CO_2 emitted) and CO_2 transportation and storage price (EUR 5 per tonne of CO_2 stored), Pre Combustion Capture plant (Scenarios 5 and 6) are not competitive with typical CCGT plant or even Post Combustion Capture plant.

- The cost per kWh for the Carbon Emissions Penalty for Scenario 1 is only EUR 0.35 per kWh whilst the cost of transportation and storage is zero. The cost per kWh associated with the Carbon Emissions Penalty for the Pre Combustion Capture plant (Scenarios 5 and 6) is around EUR 0.09 - 0.10 per kWh whilst the cost of transportation and storage is around EUR 0.20 - 0.23 per kWh. Together, the total cost of carbon for a Pre Combustion Capture plant (EUR 0.29 – 0.33) is only marginally lower than for a typical CCGT plant (EUR 0.35 per kWh). Even the cost of carbon of the Post Combustion Capture plant options is EUR 0.22 per kWh, suggesting that, given the significantly higher expenditure required on fuel and capital costs for carbon capture plant, at the at the emissions penalty and storage prices assumed in the base case there is little scope for carbon capture technologies to compete with typical CCGT plant.

10.6.2 Sensitivity Conclusions

Sensitivity analysis has been undertaken exploring the impact of changes in the gas price, the Carbon Emissions Penalty, the cost of CO_2 transportation and storage, the discount rate and the power plant capacity factor.

The key conclusions from the sensitivity analysis are as follows:

10.6.2.1 Gas price sensitivity

- Fuel is the largest component of the lifetime cost of generation in all base case scenarios and therefore any change to the gas price is likely to have a significant impact on the lifetime cost results.

- At a gas price of EUR 3 per GJ $_{LHV}$, the ranking of plant option alternatives does not change. A decrease in the gas price does however increase the attractiveness of the carbon capture scenarios relative to Scenario 1 as the lower cost of fuel reduces the impact of lower plant efficiencies on the total expenditure on fuel;

- The ranking of alternative plant options does not change if the gas price is increased to EUR 12 per GJ $_{LHV}$. An increase in the gas price does however increase the attractiveness of Scenario 1 relative to the carbon capture scenarios as the higher cost of fuel increases the impact of lower plant efficiencies on the total expenditure on fuel;

10.6.2.2 Carbon emissions penalty sensitivity

- The differential between the total lifetime cost of Scenario1 and those scenarios where carbon capture and storage facilities are installed is increased as the Carbon Emissions Penalty is reduced (and vice versa);

- At a carbon emission penalty price of EUR 50 per tonne of CO_2 emitted, the ranking of alternative plant options does not change;

- At a carbon emissions penalty of EUR 100 per tonne of CO_2 emitted, the ranking of alternatives does change, with Scenarios 3, 3b and 4 all having lower lifetime costs of generation than Scenario 1;

- Breakeven analysis indicates that the carbon emissions penalty would have to increase to EUR 80 - 90 per tonne of CO_2 emitted before Scenario 3 were to become more attractive than Scenario 1;

- Breakeven analysis indicates that the carbon emissions penalty would have to increase to EUR 60 - 70 per tonne of CO_2 emitted before Scenario 3b were to become more attractive than Scenario 1;

- Breakeven analysis indicates that the carbon emissions penalty would have to increase to EUR 70 - 80 per tonne of CO_2 emitted before Scenario 4 were to become more attractive than Scenario 1;

- Breakeven analysis indicates that the carbon emissions penalty would have to increase to EUR 150 - 160 per tonne of CO_2 emitted before Scenario 5 were to become more attractive than Scenario 1;

- Breakeven analysis indicates that the carbon emissions penalty would have to increase to EUR 270 - 280 per tonne of CO_2 emitted before Scenario 6 were to become more attractive than Scenario 1;

10.6.2.3 CO_2 transportation and storage sensitivity

- Changes in the cost of CO_2 transportation and storage have no impact on the total lifetime cost of Scenario 1;

- Changes in the cost of CO_2 transportation and storage does, however, have an impact on the relative competitiveness of those scenarios with carbon capture facilities, when compared to plant Scenario 1;

- When the cost of CO_2 transportation and storage is reduced, all of the carbon capture plant options become more competitive with Scenario 1 and when the cost of CO_2 transportation and storage is increased, the carbon capture plant options become less competitive with Scenario 1;

10.6.2.4 Discount rate sensitivity

- At a lower discount rate the cost per kWh associated with capital expenditure reduces at a greater rate for those plants with higher capital costs and therefore the higher capital cost scenarios increase their competitiveness relative to smaller capital cost scenarios;

- At a higher discount rate, the cost per kWh associated with capital expenditure increases at a greater rate for those plants with higher capital costs and therefore the lower capital cost scenarios increase their competitiveness relative to the higher capital cost scenarios.

10.6.2.5 Capacity factor sensitivity

- Lowering the capacity factor increases the cost per kWh associated with capital expenditure as the capital expenditure of the plant remains constant but the total amount of generation from the plant reduces. This trend is greater for plants with higher capital costs and therefore it can be summarised that, as the capacity factor decreases, those scenarios with higher plant capital costs become less competitive against those plants with lower capacity factors.
- The changes to the capacity factor considered as part of this study significantly change the total lifetime costs of the scenarios under consideration, although the ranking of alternatives does not change.

11. TECHNICAL AND ECONOMIC RESULTS: DISCUSSION, KEY FINDINGS AND RECOMMENDATIONS

This section provides a comparison of the key technical and economic parameters for each scenario, and includes some commentary and analysis on the results.

11.1 Summary of key parameters

The main performance parameters for each scenario are presented in Table 61. In summary;

1. A Combined cycle power plant (Reference Plant);
2. Scenario 2 not used;
3. A Combined cycle power plant with post-combustion capture using 35%wt MEA solvent;

3b. A Combined cycle power plant with a typical proprietary post-combustion capture system;

4. A Combined cycle power plant with post-combustion capture using 35%wt MEA solvent and flue-gas recirculation;
5. A Combined cycle power plant with Natural Gas reforming and pre-combustion capture;
6. A Natural Gas Reforming plant with pre-combustion capture, providing hydrogen to a remote combined cycle power plant or intermediate storage; and
7. Scenario 7 not used.

Table 61 Overall Technical and Economic Parameters Comparison

Scenario	Net Power Output (MW)	Net Efficiency (%)	Specific EPC Capital Cost (EUR /kW)	Specific CO_2 emission (tCO_2/MWh)	CO_2 capture efficiency (%)	Lifetime cost of electricity (EUR¢/kW)
Scenario 1	910.29	58.9	637	0.348	0	5.39
Scenario 3	789.33	51.0	1,401	0.041	89.9	7.66
Scenario 3b	803.95	52.0	1,165	0.040	90.0	7.07
Scenario 4	785.53	51.3	1,285	0.041	89.9	7.41
Scenario 5	849.94	42.3	1,595	0.089	81.6	9.17
Scenario 6	736.81	36.8	2,421	0.104	81.4	11.80

All figures are for base load operation; Efficiency is on LHV basis; capital cost estimate accuracy ± 40%.

11.1.1 Impacts of CCS technology on the net efficiency of gas-fired power plant

The net efficiency for each scenario is presented in Figure 36, alongside the Specific Primary Energy Consumption for CO_2 Avoided (SPECCA);

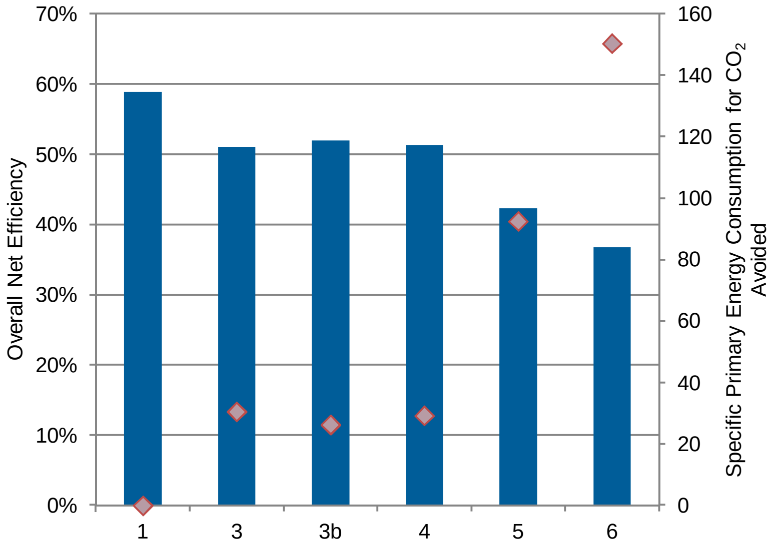


Figure 36 Comparison of net efficiency, and SPECCA for each scenario

The Specific Primary Energy Consumption for CO_2 Avoided is a dimensionless quantity which permits comparison of capture technologies which have different capture ratios. It is defined as;

$$SPECCA = \frac{HR\text{-}HRref}{(Eref\text{-}E)}$$

Where;
HR is the heat rate of the plants, expressed in kJ_{LHV} / kWh
E is the CO_2 emission rate, expressed in $kgCO_2$/kWh
'Ref' is the value found for the same plant without CCS.

From these results it can be concluded that CO_2 capture at gas fired power plants (of any type) will impose a penalty on overall efficiency in the range of 7% points to 22% points. Of the two main CO_2 capture options examined, post-combustion technology is considerably more efficient.

Given that combined cycle gas-fired CCGT represent one of the most efficient methods for generating power (with typical net efficiencies of 50-60%), it is concluded that gas plant represents a sensible option for demonstration of post-combustion CCS technology in the near term.

11.1.2 Impacts of CCS technology on the capital cost of gas-fired power plant

The capital cost breakdowns for each scenario are presented in Figure 37.

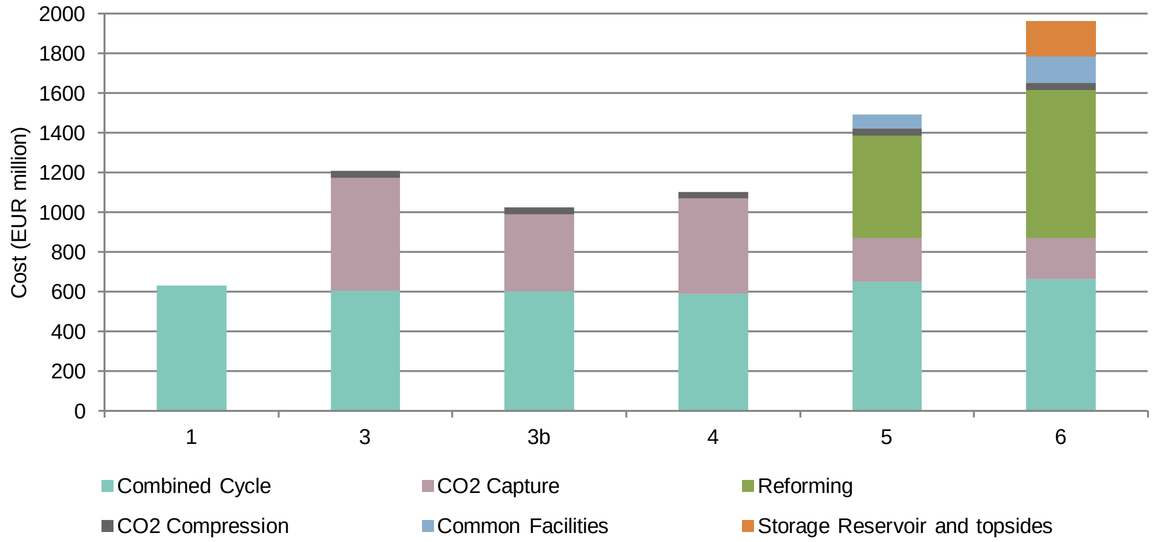


Figure 37 Comparison of capital cost breakdown for each scenario

It can be concluded that capital costs required for new build gas fired plants fitted with CO_2 capture technology are considerable, relative to unabated plant.

Of the CO_2 capture scenarios considered, post-combustion capture using a typical proprietary solvent system (Scenario 3b) has the lowest total plant capital requirement. Of the two 35%wt MEA options, the flue-gas recirculation configuration (Scenario 4) has the lowest total plant capital cost requirement, suggesting marginal improvements over that of post-combustion capture without FGR (Scenario 3). Parsons Brinckerhoff concludes that this technology merits further development and demonstration by the GT OEM's to fully understand the impacts of FGR, on combustion efficiency and GT performance. In principle, the results suggest that an optimal post-combustion capture solution would utilise a proprietary solvent in conjunction with flue-gas recirculation.

It is concluded that Scenario 6 (a natural gas reforming plant with a remote CCGT and intermediate fuel storage) does not represent a realistic option for base-load gas-fired power generation in the near term. In part, this is due to the configuration of the scenario, and the fact that the storage site (representing some EUR180million of additional capital requirement) is dedicated to a single reforming plant and CCGT. In reality, such fuel storage costs are typically offset against multiple assets. Furthermore, additional revenues which could be generated through electricity / fuel trading opportunities (which could potentially make this scenario more economically attractive) have not been considered in the economic modelling.

11.1.3 Impacts of CCS technology on the lifetime electricity cost for gas-fired power plant

The lifetime costs of electricity for each scenario are presented in Figure 38.

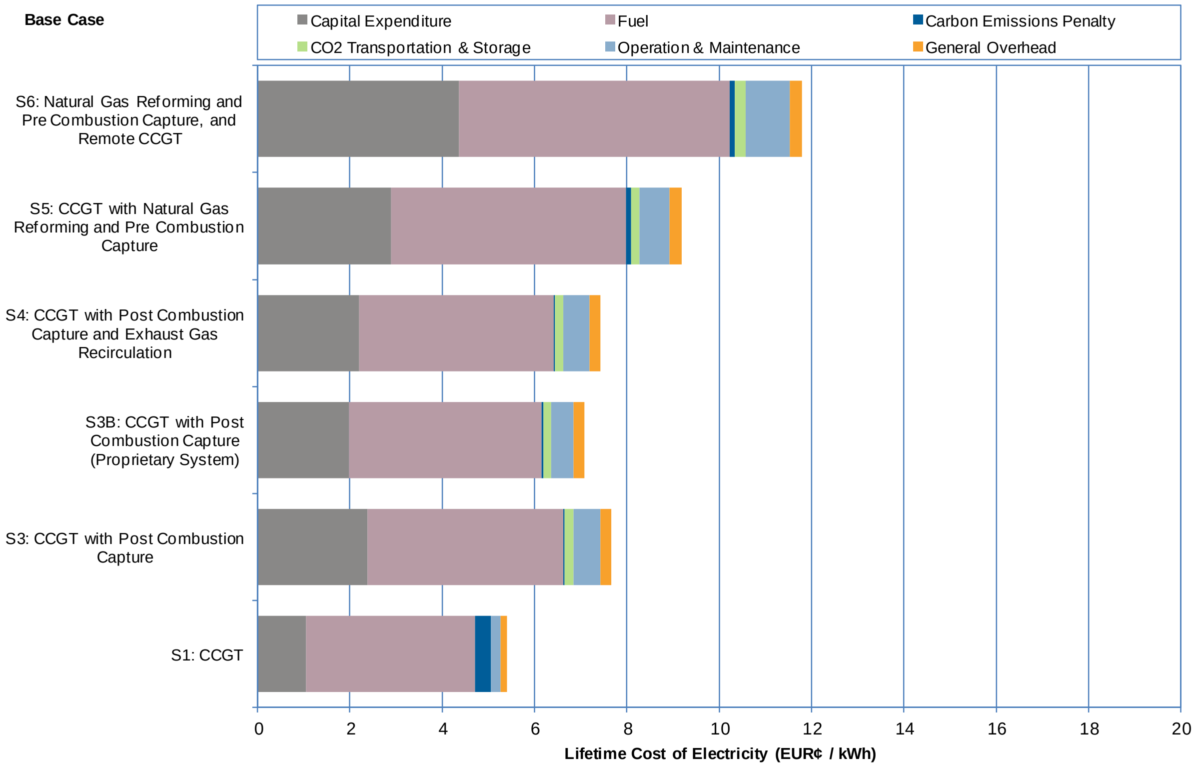


Figure 38 Lifetime cost of electricity comparison (EUR¢/kWh)

From the above it can be concluded that the lifetime costs of electricity generated by gas-fired power plants fitted with CCS are between 31% to 118% higher that of conventional, unabated CCGT.

The cost of avoiding CO_2 emissions has been calculated for each scenario by comparing the costs and emissions of the plants with CCS, with the costs and emissions of the reference case plant. Results are presented in Figure 39.

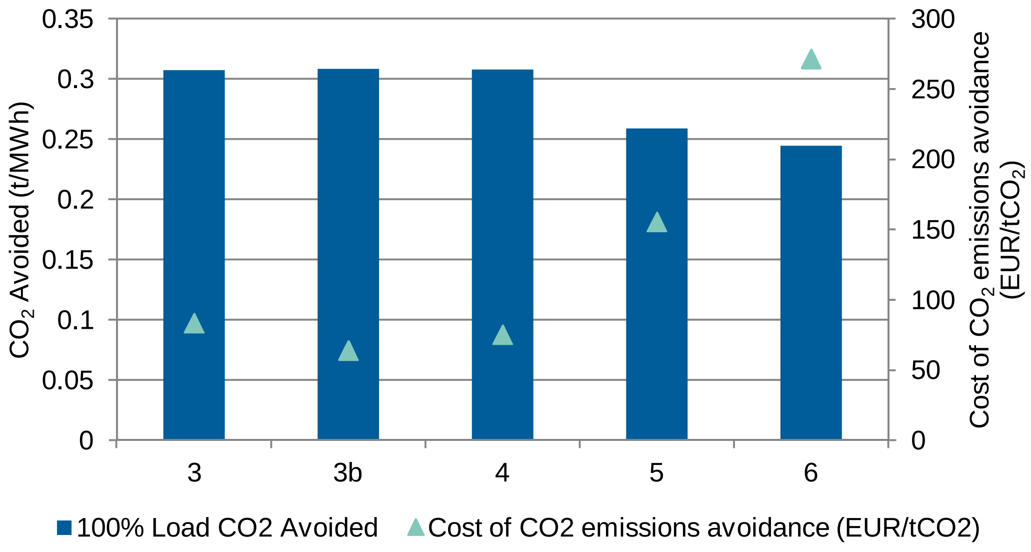


Figure 39 Comparison of CO_2 emissions avoidance costs for each scenario

The cost of avoiding CO_2 emissions have been derived as follows:

$$= \frac{\text{Electricity Cost CCS-Electricity Cost Reference Plant}}{\text{Emissions Reference Plant-Emissions CCS}}$$

where electricity costs are lifetime costs in EUR/MWh, and emissions are in tCO_2/MWh. It is noted that the lifetime costs used in this calculation are based on a EUR0 Carbon Emission Penalty.

Results are also presented in Table 62:

Table 62 Costs of CO_2 emissions avoidance

Scenario	Specific CO_2 emission (tCO_2/MWh)	Lifetime cost of electricity (Base) (EUR/MWh)	Lifetime cost of electricity (EUR0 CEP) (EUR/MWh)	Cost of CO_2 emissions avoidance (EUR/tCO_2)
Scenario 1	0.348	53.9	50.5	-
Scenario 3	0.041	76.6	76.2	86.63
Scenario 3b	0.040	70.7	70.3	64.21
Scenario 4	0.041	74.1	73.7	75.42
Scenario 5	0.089	91.7	90.8	155.68
Scenario 6	0.104	118.0	117.0	271.72

It can be concluded that the Carbon Emissions Penalty would need to increase to:

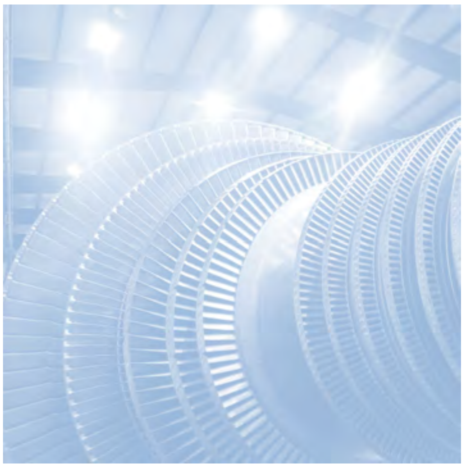
- EUR 60 - 80 per tonne of CO_2 emitted before post-combustion capture becomes commercially viable; and
- EUR 150 - 270 per tonne of CO_2 emitted before natural gas reforming and pre-combustion capture becomes commercially viable;

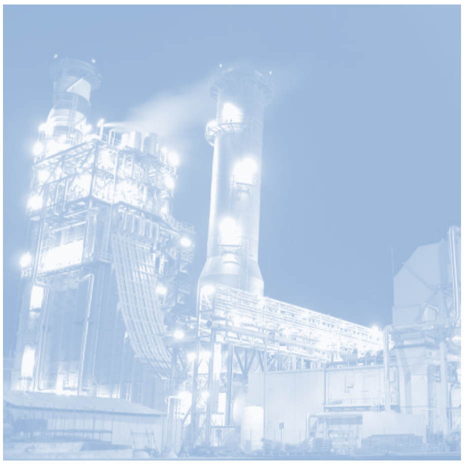
11.2 Conclusion

- Gas fired power generation has a crucial role to play in the future energy mix, given the abundance of natural gas as a fossil fuel and the relative low emissions when compared to other fuels used for power generation such as coal. In the near term, significant investment in new gas fired generating capacity is expected in order to replace aging assets which must retire under existing environmental legislation such as LCPD and IED, and other emerging emissions performance standards. In the long-term, gas fired power generation is expected to play a crucial role in maintaining generation flexibility which might otherwise be constrained by the variability of high-levels of renewable generation which is required to meet global emissions targets.
- It is important that CO_2 capture for gas-fired power plants is demonstrated in the near term, such that it can be deployed on a global scale in the period 2020 to 2050.
- This report concludes that Gas + CCS has a significant impact on the overall efficiency of gas-fired power plants, typically in the range of 7% points for post-combustion capture. It is further concluded the lifetime cost of electricity from gas-fired power plants with post-combustion capture is around EUR¢ 7/kWh – EUR¢ 8/kWh, compared to around EUR¢ 5/kWh for conventional, unabated CCGT.
- It is concluded that reforming of natural gas for the purposes of hydrogen production and pre-combustion capture of CO_2, is not a viable power generation technology in the near term, and that post-combustion capture of CO_2 presents the most realistic option for CO_2 abatement of power generation assets.
- It is recognised that cost improvements of Gas + CCS can be realised as the technology is deployed. Given the major contribution of fuel costs to the lifetime cost of electricity generation for these Scenarios, the authors believe that efforts to optimise and improve the net efficiency of designs represents the quickest way to realise cost reductions.
- Notwithstanding the potential cost reductions which may be realised in the future is concluded that for widespread deployment of Gas + CCS to occur (at a scale required to meet necessary reductions in CO_2 emissions from power generation) then a strong carbon emissions penalty price of at least EUR 60 / tCO_2 is required.

APPENDIX

A




PROCESS FLOW DIAGRAMS

APPENDIX A-1: PROCESS FLOW DIAGRAMS SCENARIO 1

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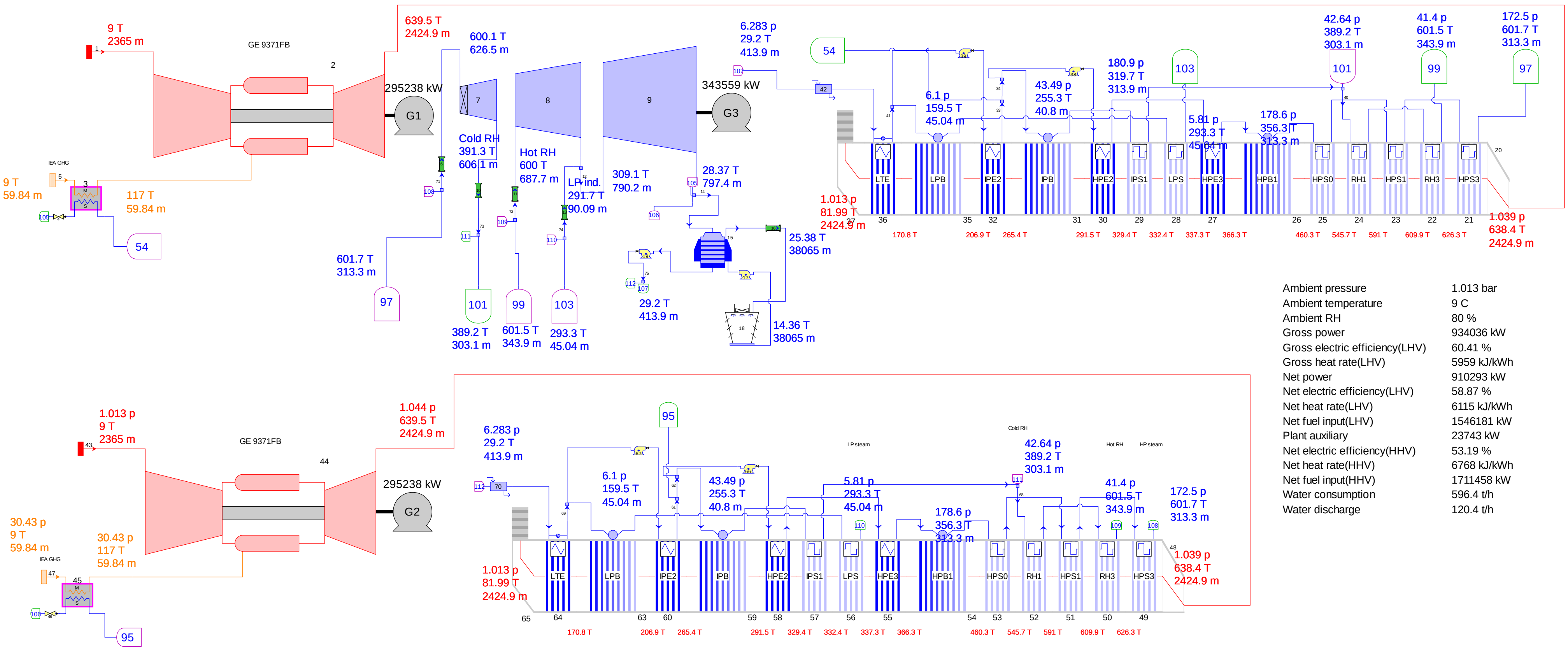
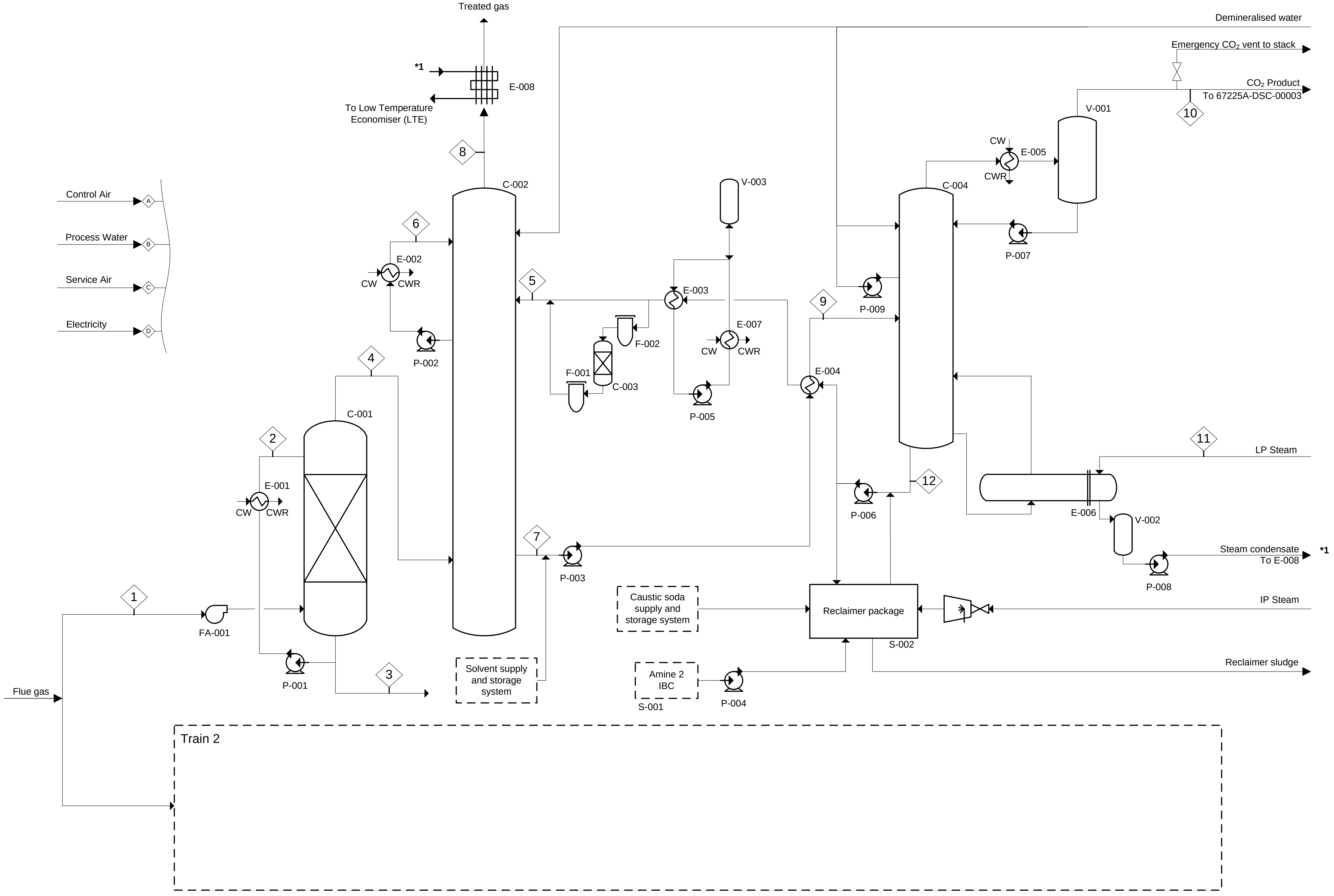


Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	934036 kW
Gross electric efficiency(LHV)	60.41 %
Gross heat rate(LHV)	5959 kJ/kWh
Net power	910293 kW
Net electric efficiency(LHV)	58.87 %
Net heat rate(LHV)	6115 kJ/kWh
Net fuel input(LHV)	1546181 kW
Plant auxiliary	23743 kW
Net electric efficiency(HHV)	53.19 %
Net heat rate(HHV)	6768 kJ/kWh
Net fuel input(HHV)	1711458 kW
Water consumption	596.4 t/h
Water discharge	120.4 t/h

APPENDIX A-2: PROCESS FLOW DIAGRAMS SCENARIO 3



Rev	Date	Description	By	Chk	App
3	18-11-11	Final	FH	NS	NS
2	27-07-11	Working draft (internal changes)	FH	AL	NS
1		Original draft	FH	AL	NS

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Client:

IEA Environmental Projects Ltd

Site / Project:

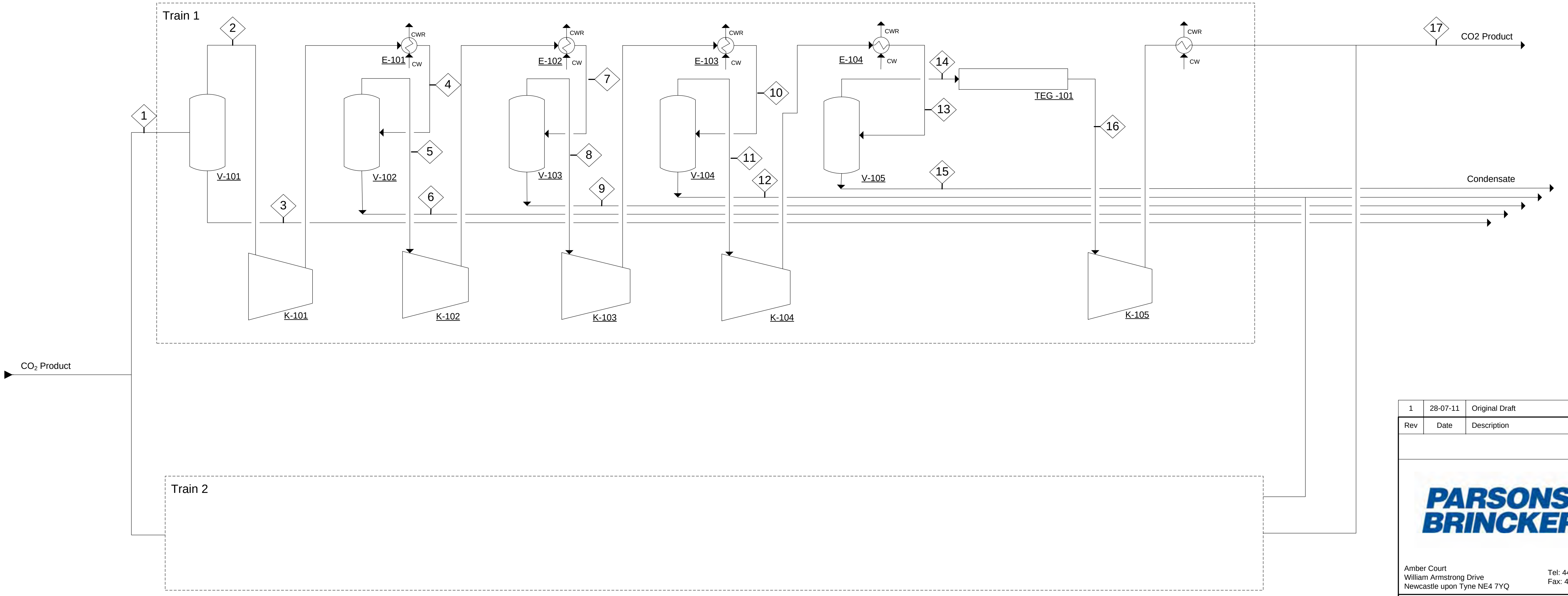
CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram Post-Combustion Carbon Capture (Scenario 3)

Drawn: FH			Checked: AL		
Designed: AL			Approved: NS		
Date: 10/08/11	Scale: NTS		A3	Sheet:	
Project Number:	Drawing Number:				Revision:
64225A	-DSC-00002				3

C-001 DCC (Direct Contact Cooler)	E-001 DCC Cooler	E-005 Stripper condenser	FA-001 Flue gas fan	F-001 Downstream guard filter	P-001 DCC Pump A/B	P-005 Cooling water pumps (closed loop)	P-009 Stripper WW pump (A/B)	S-001 Amine 2 IBC Filing pakage	V-001 Stripper overhead received
C-002 Absorber	E-002 Absorber WW Cooler	E-006 Reboiler		F-002 Upstream guard filter	P-002 Absorber 1st WW pump	P-006 Lean amine pumps (A/B)		S-002 Reclaimer package	V-002 Reboiler condensate drum
C-003 Carbon filter	E-003 Lean amine cooler	E-007 Cooling water coolers closed loop			P-003 Rich amine pumps (A/B)	P-007 Stripper reflux pump (A/B)			V-003 Cooling water expansion vessel (closed loop)
C-004 Stripper	E-004 Lean/rich exchangers (A/B/C/D/E/F)	E-008 Condensate Cooler			P-004 Amine 2 storage pump	P-008 Condensate return pump (A/B)			



E-101
1st stage discharge cooler

E-105
5th stage discharge cooler

K-101/2/3/4/5
Product CO_2 compressor

TEG-101
TEG Dehydration package

V-101
1st stage KO drum

V-105
5th stage suction KO drum

E-102
2nd stage discharge cooler

V-102
2nd stage KO drum

E-103
3rd stage discharge cooler

V-103
3rd stage suction KO drum

E-104
4th stage discharge cooler

V-104
4th stage suction KO drum

Rev	Date	Description	By	Chk	App
1	28-07-11	Original Draft	FH	AL	NS

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IEA Environmental Projects Ltd

Site / Project:

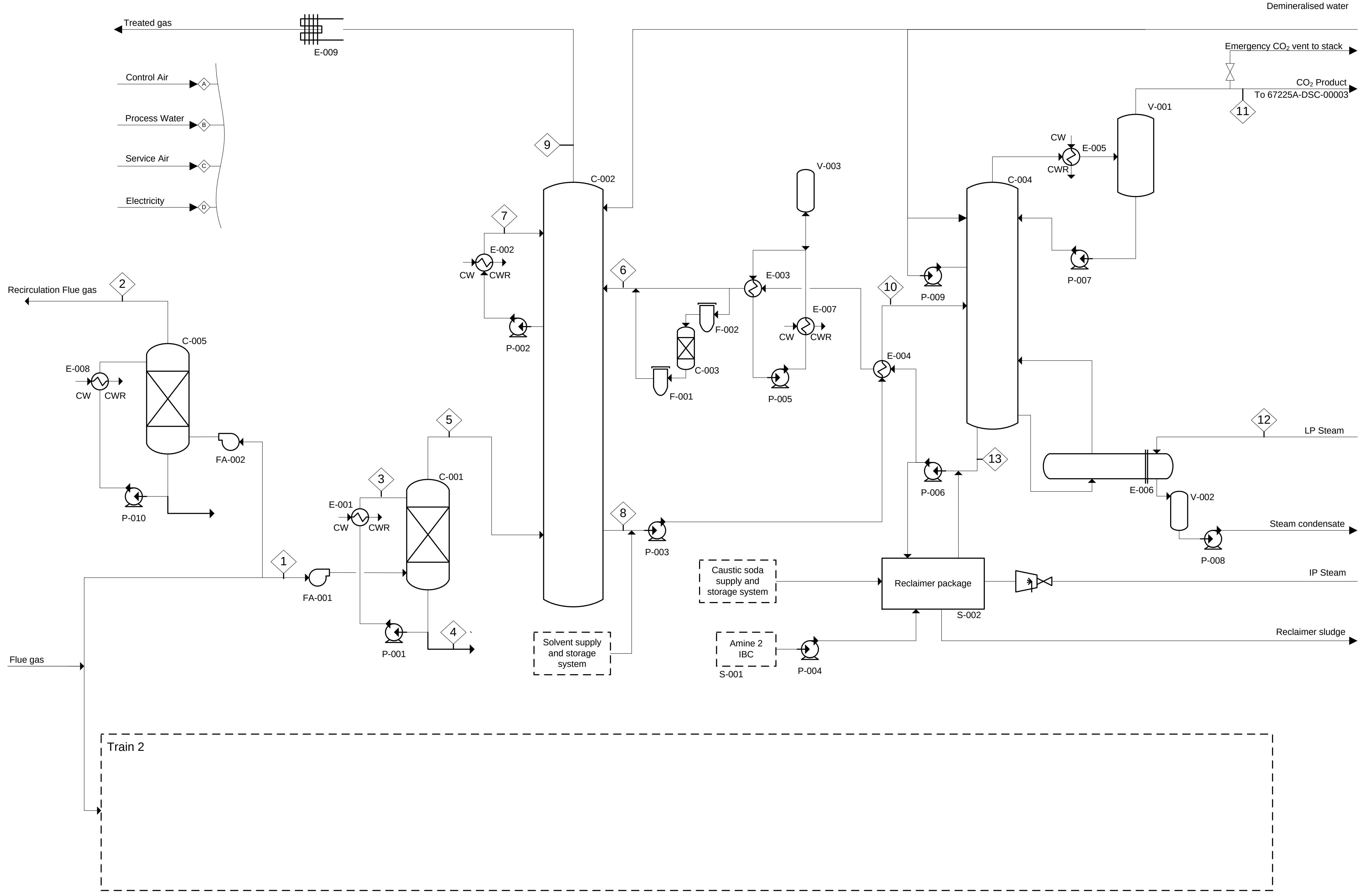
CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram CO_2 Compression

Drawn: FH		Checked: AL	
Designed: AL		Approved: NS	
Date: 28/07/11	Scale: NTS	A3	Sheet:
Project Number:	Drawing Number:		Revision:
64225A	-DSC-00003		1

APPENDIX A-3: PROCESS FLOW DIAGRAMS SCENARIO 4



C-001 DCC (Direct Contact Cooler) #1	C-005 DCC (Direct Contact Cooler) #2	E-001 DCC #1 Cooler	E-005 Stripper condenser	E-009 Condensate Cooler	FA-001 Flue gas fan #1	F-001 Downstream guard filter	P-001 DCC Pump #1 A/B	P-005 Cooling water pumps (closed loop)	P-009 Stripper WW pump (A/B)	S-001 Amine 2 IBC Filing pakage	V-001 Stripper overhead received
C-002 Absorber		E-002 Absorber WW Cooler	E-006 Condensate cooler		FA-001 Flue gas fan #2	F-001 Upstream guard filter	P-002 Absorber 1st WW pump	P-006 Lean amine pumps (A/B)	P-010 DCC Pump #2 (A/B)	S-002 Reclaimer package	V-002 Reboiler condensate drum
C-003 Carbon filter		E-003 Lean amine cooler	E-007 Cooling water coolers closed loop				P-003 Rich amine pumps (A/B)	P-007 Stripper reflux pump (A/B)			V-002 Cooling water expansion vessel (closed loop)
C-004 Stripper		E-004 Lean/rich exchangers (A/B/C/D/E/F)	E-008 DCC #2 Cooler				P-004 Amine 2 storage pump	P-008 Condensate return pump (A/B)			

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Client:

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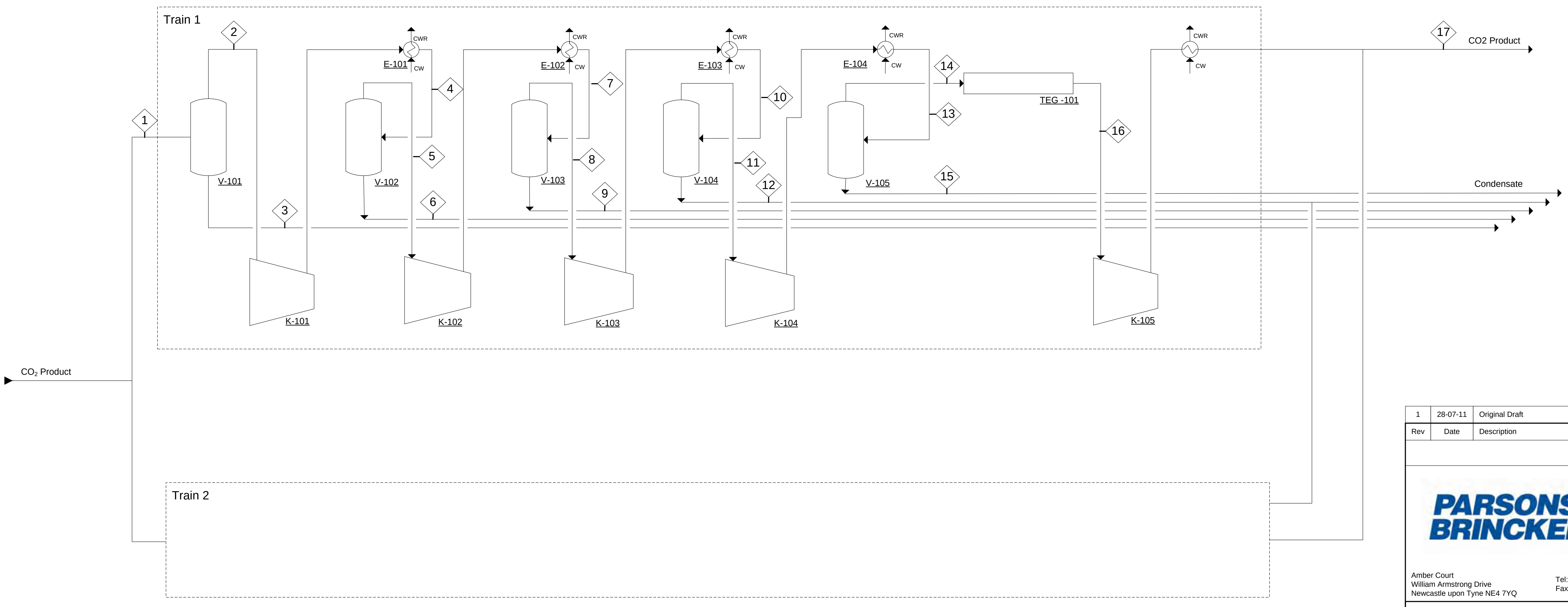
Site / Project:

CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram Post-Combustion Carbon Capture with Flue Gas Recirculation (Scenario 4)

Drawn: FH			Checked: AL		
Designed: AL			Approved: NS		
Date: 10-08-11	Scale: NTS		A3	Sheet: 1/1	
Project Number:	Drawing Number:			Revision:	
64225A	-DSC-00007			2	



E-101
1^{st} stage discharge cooler

E-102
2^{nd} stage discharge cooler

E-103
3^{rd} stage discharge cooler

E-104
4^{th} stage discharge cooler

E-105
5^{th} stage discharge cooler

K-101/2/3/4/5
Product CO_2 compressor

TEG-101
TEG Dehydration package

V-101
1^{st} stage KO drum

V-102
2^{nd} stage KO drum

V-103
3^{rd} stage suction KO drum

V-104
4^{th} stage suction KO drum

V-105
5^{th} stage suction KO drum

Rev	Date	Description	By	Chk	App
1	28-07-11	Original Draft	FH	AL	NS

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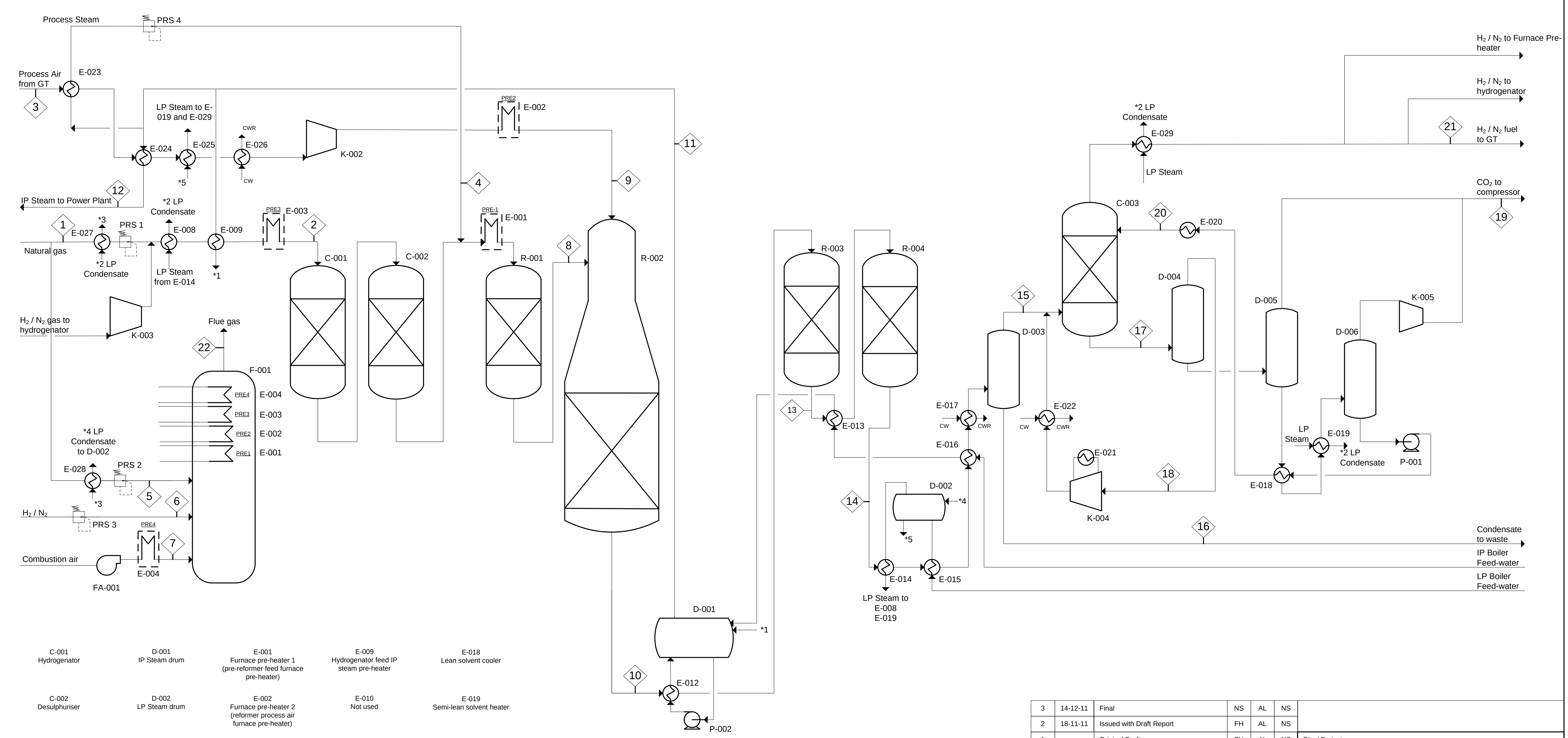
Site / Project:
CO_2 Capture at Gas Fired Power Plants Study

Title:
Process Flow Diagram CO_2 Compression

Drawn: FH | Checked: AL
Designed: AL | Approved: NS
Date: 28/07/11 | Scale: NTS | A3 | Sheet:

Project Number: 64225A
Drawing Number: -DSC-00003
Revision: 1

APPENDIX A-4: PROCESS FLOW DIAGRAMS SCENARIO 5



C-001
Hydrogenator

C-002
Desulphuriser

C-003
CO_2 Absorber

D-001
IP Steam drum

D-002
LP Steam drum

D-003
Knock-out drum

D-004
Flash drum 1

D-005
Flash drum 2

D-006
Flash drum 3

E-001
Furnace pre-heater 1 (pre-reformer feed furnace pre-heater)

E-002
Furnace pre-heater 2 (reformer process air furnace pre-heater)

E-003
Furnace pre-heater 3 (hydrogenator feed furnace pre-heater)

E-004
Furnace pre-heater 4 (combustion air pre-heater)

E-005
Not used

E-006
Not used

E-007
Not used

E-008
Hydrogenator feed LP steam pre-heater

E-009
Hydrogenator feed IP steam pre-heater

E-010
Not used

E-011
Not used

E-012
Syngas cooler 1 (IP steam generator)

E-013
Syngas cooler 2 (IP boiler feedwater heater)

E-014
LT Shift reactor product cooler 1 (LP steam generator)

E-015
LT Shift reactor product cooler 2 (LP boiler feedwater heater)

E-016
LT Shift reactor product cooler 3 (IP boiler feedwater heater)

E-017
LT Shift reactor product cooler 4 (cooling water)

E-018
Lean solvent cooler

E-019
Semi-lean solvent heater

E-020
Lean solvent chiller

E-021
CO_2 Absorber gas recycle compressor inter-cooler

E-022
CO_2 Absorber gas recycle compressor cooler

E-023
Process Air Cooler 1 (Process Steam Superheater)

E-024
Process Air Cooler 2 (IP Steam export superheater)

E-025
Process Air Cooler 3 (LP Steam generator)

E-026
Process Air Cooler 4 (Cooling Water)

E-027
Natural Gas Let-down station heater

E-028
Furnace Natural Gas let-down station heater

E-029
GT Fuel Heater

FA-001
Furnace Combustion air fan

F-001
Furnace pre-heater

K-001
Not used

K-002
GT Process air booster compressor

K-003
H_2/N_2 gas compressor

K-004
CO_2 Absorber gas recycle compressor

K-005
Flash drum 3 CO_2 booster compressor

P-001
Lean solvent pump

P-002
IP Feedwater pump

R-001
Pre-reformer

R-002
Autothermal reformer

R-003
High temperature shift reactor

R-004
Low temperature shift reactor

PRS1
Pressure reducing station 1 (Natural Gas to Process)

PRS2
Pressure reducing station 2 (Natural Gas to Furnace Pre-heater)

PRS3
Pressure reducing station 3 (Hydrogen / Nitrogen to Furnace Pre-heater)

PRS4
Pressure reducing station 4 (Process Steam)

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3	14-12-11	Final	NS	AL	NS
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1	-	Original Draft	FH	AL	NS

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Client:
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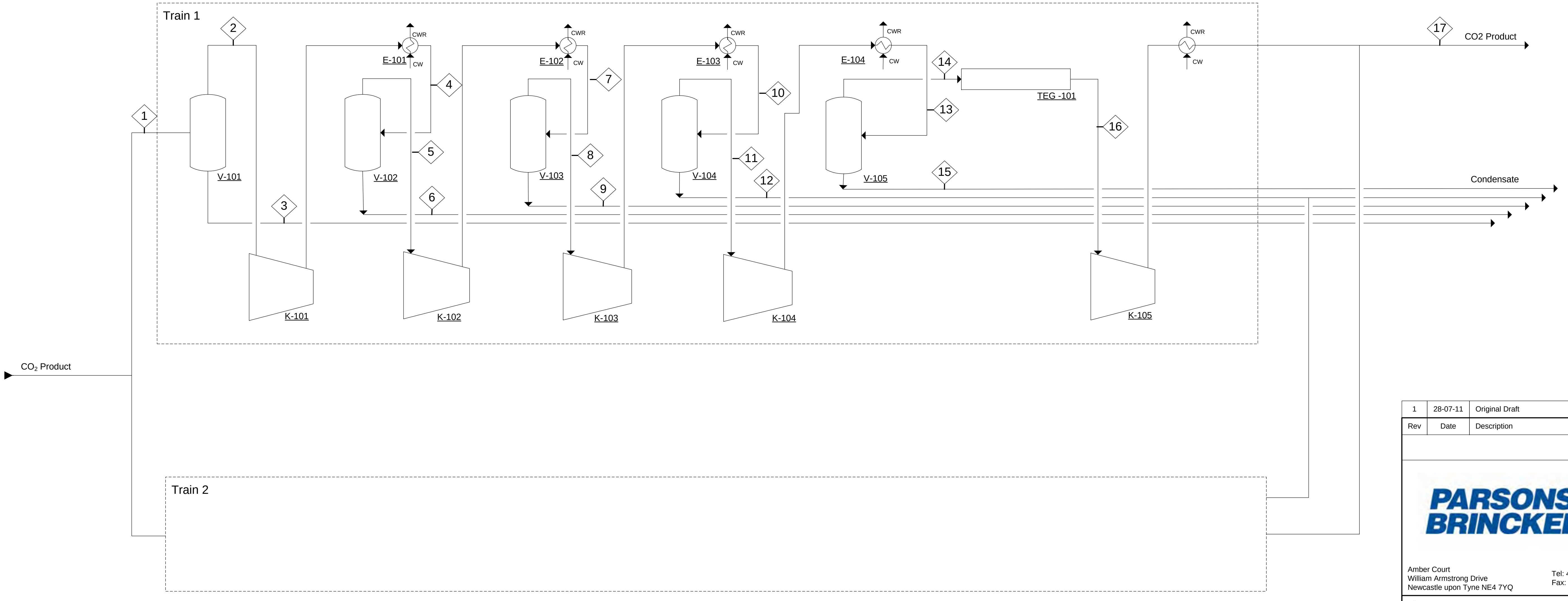
Site / Project:
CO_2 Capture at Gas Fired Power Plants Study

Title:
Process Flow Diagram Pre-Combustion Carbon Capture (Scenario 5)

Drawn: FH		Checked: AL	
Designed: AL		Approved: NS	
Date: 19-08-11	Scale: NTS	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00005		Revision: 3



E-101	E-105	K-101/2/3/4/5	TEG-101	V-101	V-105
1st stage discharge cooler	5th stage discharge cooler	Product CO_2 compressor	TEG Dehydration package	1st stage KO drum	5th stage suction KO drum
E-102				V-102	
2nd stage discharge cooler				2nd stage KO drum	
E-103				V-103	
3rd stage discharge cooler				3rd stage suction KO drum	
E-104				V-104	
4th stage discharge cooler				4th stage suction KO drum	

Rev	Date	Description	By	Chk	App
1	28-07-11	Original Draft	FH	AL	NS

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IEA Environmental Projects Ltd

Site / Project:

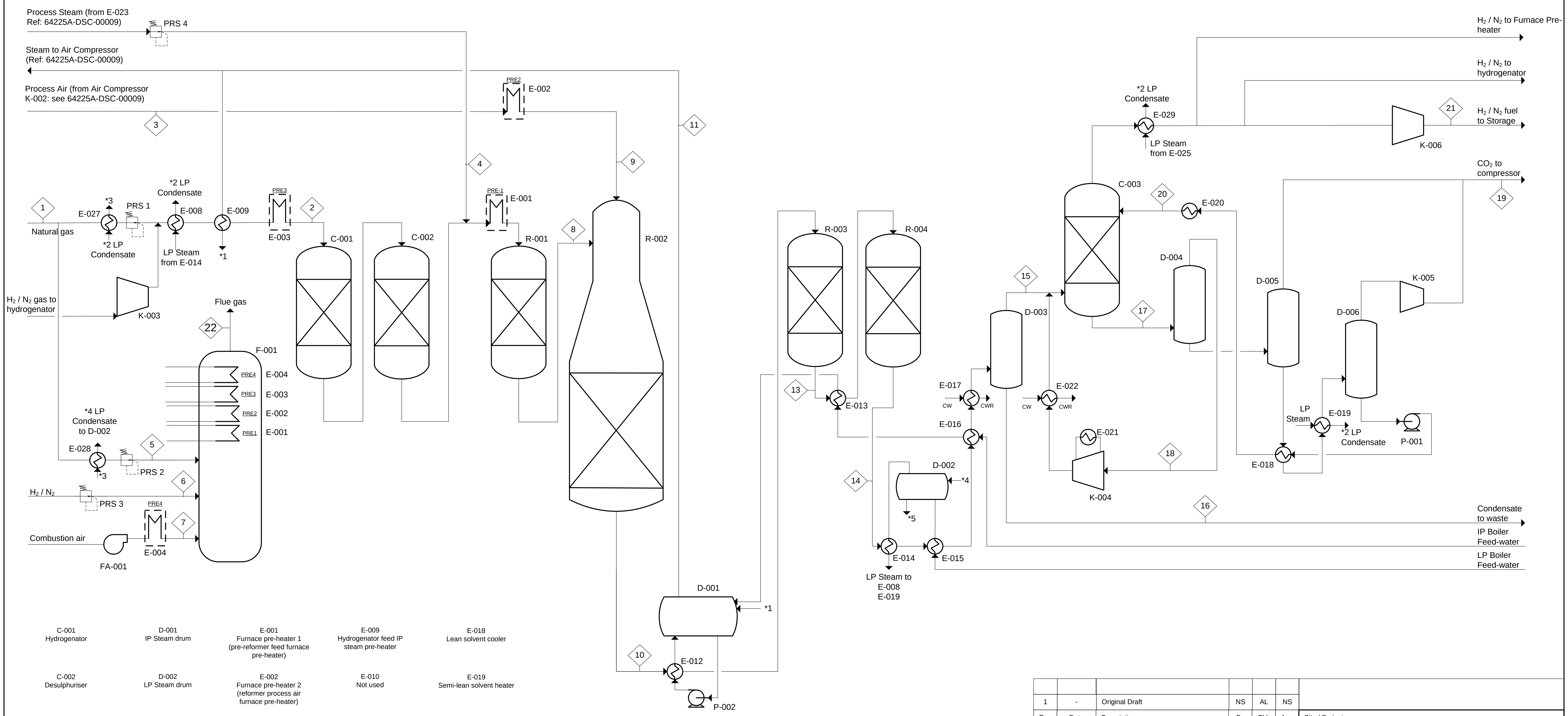
CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram CO_2 Compression

Drawn: FH		Checked: AL	
Designed: AL		Approved: NS	
Date: 28/07/11	Scale: NTS	A3	Sheet:
Project Number:	Drawing Number:		Revision:
64225A	-DSC-00003		1

APPENDIX A-5: PROCESS FLOW DIAGRAMS SCENARIO 6



C-001
Hydrogenator

C-002
Desulphuriser

C-003
CO_2 Absorber

D-001
IP Steam drum

D-002
LP Steam drum

D-003
Knock-out drum

D-004
Flash drum 1

D-005
Flash drum 2

D-006
Flash drum 3

E-001
Furnace pre-heater 1
(pre-reformer feed furnace pre-heater)

E-002
Furnace pre-heater 2
(reformer process air furnace pre-heater)

E-003
Furnace pre-heater 3
(hydrogenator feed furnace pre-heater)

E-004
Furnace pre-heater 4
(combustion air pre-heater)

E-005
Not used

E-006
Not used

E-007
Not used

E-008
Hydrogenator feed LP steam pre-heater

E-009
Hydrogenator feed IP steam pre-heater

E-010
Not used

E-011
Not used

E-012
Syngas cooler 1
(IP steam generator)

E-013
Syngas cooler 2
(IP boiler feedwater heater)

E-014
LT Shift reactor product cooler 1
(LP steam generator)

E-015
LT Shift reactor product cooler 2
(LP boiler feedwater heater)

E-016
LT Shift reactor product cooler 3
(IP boiler feedwater heater)

E-017
LT Shift reactor product cooler 4
(cooling water)

E-018
Lean solvent cooler

E-019
Semi-lean solvent heater

E-020
Lean solvent chiller

E-021
CO_2 Absorber gas recycle compressor inter-cooler

E-022
CO_2 Absorber gas recycle compressor cooler

E-023
See 64225-DSC-00009

E-024
See 64225-DSC-00009

E-025
See 64225-DSC-00009

E-026
See 64225-DSC-00009

E-027
Natural Gas Let-down station heater

E-028
Furnace Natural Gas let-down station heater

E-029
GT Fuel Heater

FA-001
Furnace Combustion air fan

F-001
Furnace pre-heater

K-001
Not used

K-002
See 64225-DSC-00009

K-003
H_2/N_2 gas compressor

K-004
CO_2 Absorber gas recycle compressor

K-005
Flash drum 3 CO_2 booster compressor

P-001
Lean solvent pump

P-002
IP Feedwater pump

R-001
Pre-reformer

R-002
Autothermal reformer

R-003
High temperature shift reactor

R-004
Low temperature shift reactor

PRS1
Pressure reducing station 1 (Natural Gas to Process)

PRS2
Pressure reducing station 2 (Natural Gas to Furnace Pre-heater)

PRS3
Pressure reducing station 3 (Hydrogen / Nitrogen to Furnace Pre-heater)

PRS4
Pressure reducing station 4 (Process Steam)

Rev	Date	Description	By	Chk	App
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IEA Environmental Projects Ltd

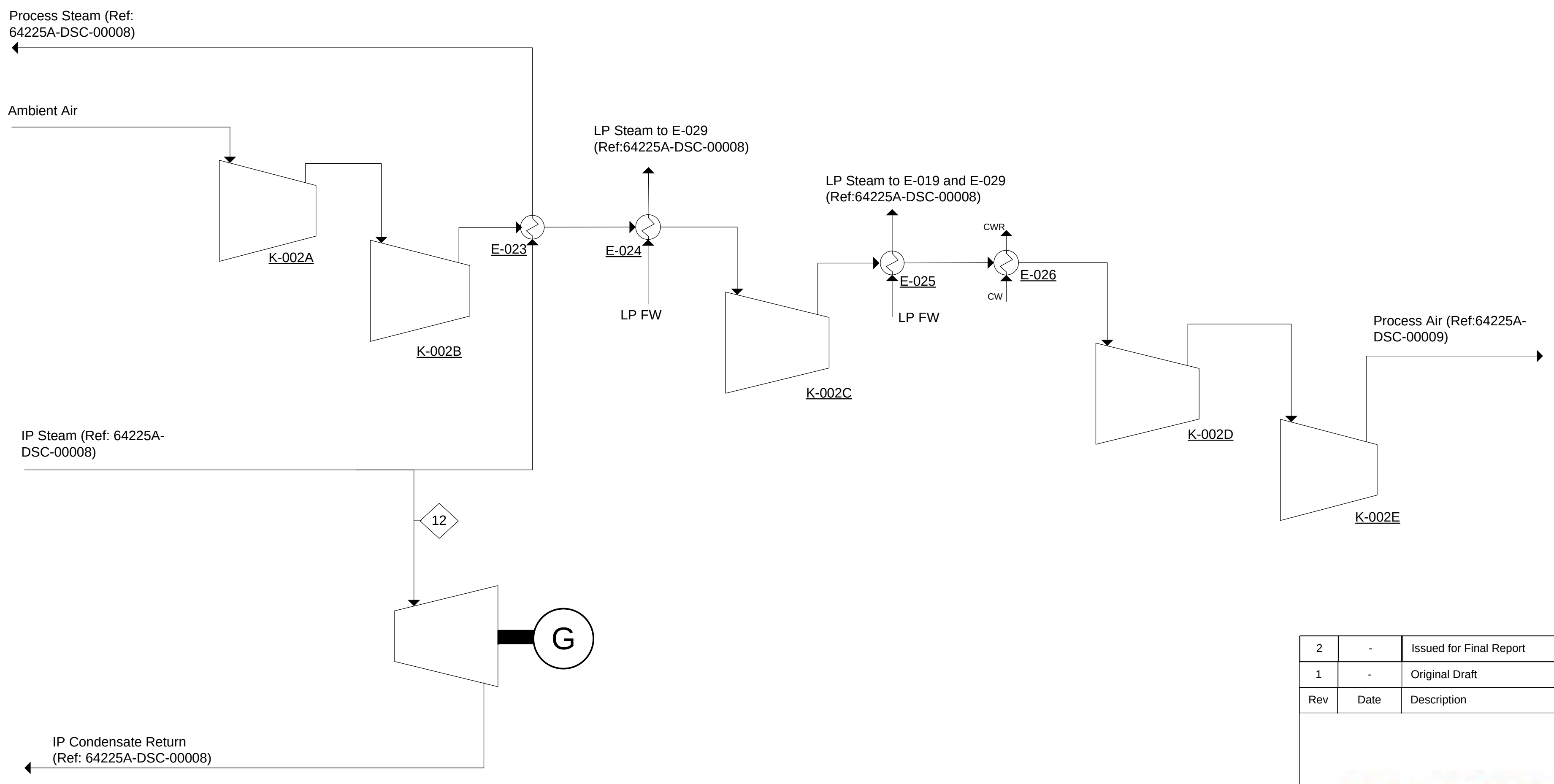
Site / Project:

CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram Pre-Combustion Carbon Capture (Scenario 6)

Drawn:	FH		Checked:	AL	
Designed:	AL		Approved:	NS	
Date:	19-08-11	Scale:	NTS	A3	Sheet:
Project Number:	Drawing Number:			Revision:	
64225A	-DSC-00008			1	



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2	-	Issued for Final Report	NS	AL	NS
1	-	Original Draft	NS	AL	NS

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Client:

IEA Environmental Projects Ltd

Site / Project:

CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram Pre-Combustion Carbon Capture : Air Compressor (Scenario 6)

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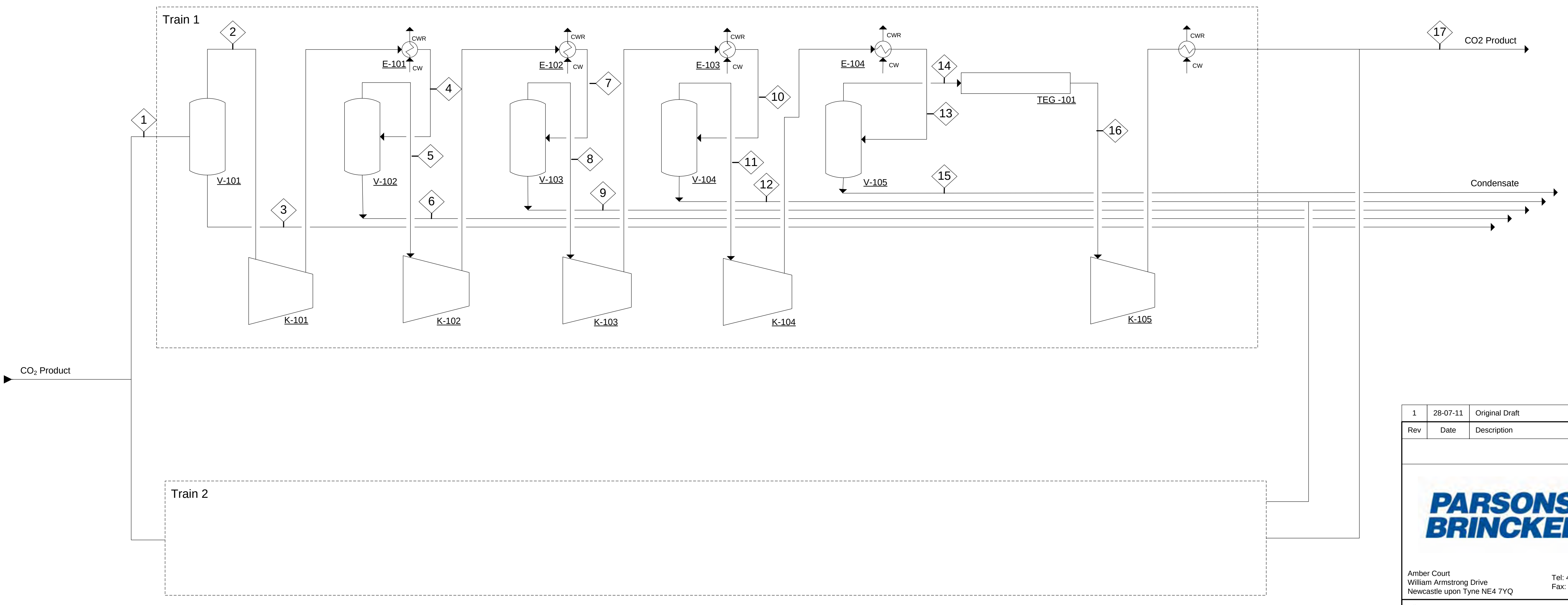
Designed: AL		Approved: NS	
Date: 19-08-11	Scale: NTS	A3	Sheet:

Project Number:	Drawing Number:	Revision:
64225A	-DSC-00009	2



E-101
1^{st} stage discharge cooler

E-102
2^{nd} stage discharge cooler

E-103
3^{rd} stage discharge cooler

E-104
4^{th} stage discharge cooler

E-105
5^{th} stage discharge cooler

K-101/2/3/4/5
Product CO_2 compressor

TEG-101
TEG Dehydration package

V-101
1^{st} stage KO drum

V-102
2^{nd} stage KO drum

V-103
3^{rd} stage suction KO drum

V-104
4^{th} stage suction KO drum

V-105
5^{th} stage suction KO drum

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IEA Environmental Projects Ltd

Site / Project:

CO_2 Capture at Gas Fired Power Plants Study

Title:

Process Flow Diagram CO_2 Compression

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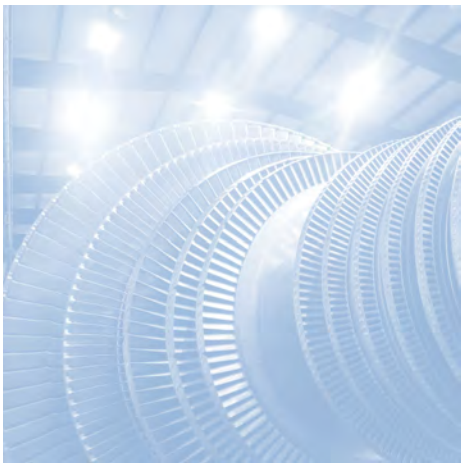
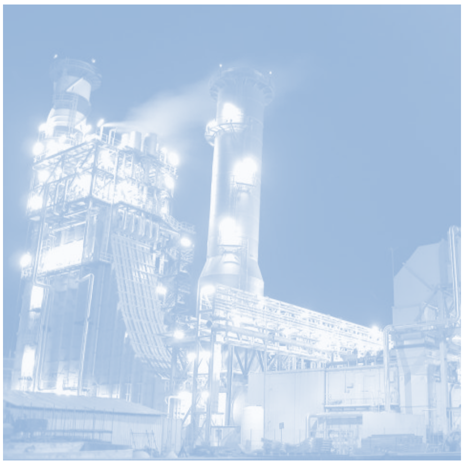
Designed: AL | Approved: NS
Date: 28/07/11 | Scale: NTS | A3 | Sheet:

Project Number:	Drawing Number:	Revision:
64225A	-DSC-00003	1

APPENDIX

B




EQUIPMENT LISTS

APPENDIX B-1: EQUIPMENT LIST SCENARIO 1

Reference Plant Scenario 1

	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des		
Gas Turbine Package		**GE 9371FB**	**2**								
	Combustion Turbine Genset										
	Inlet Filter / Silencer System w/elements)										
	Electrical / Control / Instrumentation Package										
	Gas Fuel Package										
	Fuel Heating Package										
	Starting Package										
	Lube Oil Package w/main, auxilliary & emergency pump										
	Compressor Water Wash System										
Steam Turbine Package			**1**								
	Turbine										
	Generator										
	Exhaust System										
	Electrical / Control / Instrumentation Package										
	Lube Oil Package w/main, auxilliary & emergency pump										
Heat Recovery Steam Generator			**2**								
	Gas Turbine Exhaust Transition										
	Main Stack										
	Instrumentation										
	Steam Vents & Water Drains										
	Non-Return Valves										
Water Cooled Condenser			**1**								
	Condenser										
Continuous Emissions Monitoring System			**1**								
	Enclosures										
	Electronics, Display Units, Printers & Sensors										
Distributed Control System			**1**								
	Enclosures										
	Electronics, Display Units, Printers & Sensors										
Transmission Voltage Equipment			**1**								
	Transformers										
	Circuit Breakers										
	Miscellaneous Equipment										
Generator Voltage Equipment			**1**								
	Generator Buswork										
	Circuit Breakers										
	Current Limiting Reactors										
	Miscellaneous Equipment										
Pumps											
	HP Feedwater Pump		**6**								
	IP Feedwater Pump		**6**								
	Condensate Forwarding Pump		**2**								
	Condenser Cooling Water Pump		**2**								
	Condenser Vacuum Pump		**2**								
	Treated Water Pump		**1**								
	Demineralised Water Pump		**2**								
	Raw Water Pump 1		**1**								
	Raw Water Pump 2		**1**								
	Raw Water Pump 3		**1**								
	Auxiliary Boiler Feedwater Pump		**2**								
	Aux Cooling Water Pump (closed loop)		**2**								
	Diesel Fire Pump		**1**								
	Electric Fire Pump		**1**								
	Jockey Fire Pump		**1**								

Reference Plant Scenario 1

	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des		
	Aux Cooling Water Pump (open loop)		2								
Tanks											
	Demineralized Water		1								
	Raw Water		1								
	Neutralized Water		1								
	Acid Storage		2								
	Caustic Storage		2								
	Dedicated Fire Protection Water Storage		1								
Cooling Tower			1								
Auxiliary Cooling Water Heat Exchangers			1								
Auxiliary Boiler			1								
Makeup Water Treatment System			1								
Waste Water Treatment System			1								
Bridge Cranes			2								
	GT Crane										
	ST Crane										
Station Instrument Air Compressors			2								
Emergency Generator			1								
General Plant Instrumentation			1								
Medium Voltage Equipment			1								
	Transformers										
	Circuit Breakers										
	Switchgear										
	Motor Control Centres										
	Miscellaneous										
Low Voltage Equipment			1								
	Transformers										
	Circuit Breakers										
	Switchgear										
	Motor Control Centres										
	Miscellaneous										
Miscellaneous Equipment			1								

APPENDIX B-2: EQUIPMENT LIST SCENARIO 3

Post-Combustion Capture Scenario 3 (PFD Drawing: 64225A-DSC-00002)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
	Flue gas ducting to Fan FA-001 / DCC	Square	1/train	CS	2430 t/h	97.00	150 / -10	0.10	0.30		6m x 6m	Estimated lenghth 73m
	Flue gas ducting DCC to absorber	Square	1/train	CS	2430 t/h	33.00	100 / -10	0.10	0.30		6m x 6m	Estimated length 35m
	Duct work from Absorber	Square	1/train	CS	2294 t/h	35.00	80 / -10	0.00	0.10		5.5m x 5.5m	Estmated length 3m
	GRP Stack located on top of Absorber & condensate cooler	Cylindrical	1/train	GRP	2294 t/h	65.00	80 / -10	0.00	0.10		6.5m ID	Estimated height 10m
E-008	Flue gas reheater / condensate cooler	Finned tube	1/train	Tube: CS Fin: Aluminium	H: C: 2294 t/h	H 129 - 51 ; C: 35 - 65	150 / -10	H: 1.0 ; C: 0.01	2.00		16.3m L x 18.08m W x 0.43m H	1016 finned tubes, 1" diameter, 15m long. Duty 19.6MW
C-001	DCC (Direct Contact Cooler)	Rectangular column	1/train	Concrete with epoxy lining. SS316 packing and internals	2430 t/h	80.00	150 / -10	0.10	0.30		10m L x 27m W x 19m H	Demister, distribution system, packed bed and bed support
	DCC Packing	Structured Mellapak 250Y	1/train	SS316L		80.00	150 / -10	0.10	0.30		10m L x 27m W x 3m H	
	DCC Distributor/Collector		1/train	SS316L		80.00	150 / -10	0.10	0.30			
P-001	DCC Pump	Centrifugal	2/train	SS316L	4016 t/hr x 1.1	50.00	80 / -10	4.99	7.00	0.7 MW	Baseplate L = 1.923m, W =1.923m	
E-001	DCC Cooler	Plate and frame	3/train	CS	H:4016 t/h C: 7748 t/h	H: 51.2-30; C: 14-25	80 / -10	H: 4.99; C: 1.49	7.00		4m L x 1.6m W x 4m H	
FA-001	Flue Gas Fan	Axial	1/train	CS	2430 x 1.1 t/h	108.00	150 / -10	0.10	0.30	9.0MW		∆P = 100mbar
C-002	Absorber	Rectangular column	1/train	Concrete with polypropylene lining. SS316 structured packing and internals	2357 t/h	33.00	80 / -10	0.05	0.10		15.5m L x 25m W x 85m H	
	Absorber packing	Structured Mellapak 250Y	1/train	SS316L		52.00	80 / -10	0.05	0.10		15.5m L x 25m W x 20m H	
E-002	Absorber WW cooler	Shell & Tube	1/train	Shell: SS316; Tubes: SS316	5458 t/h CW / 2477 t/h WW	H:48 - 25 ; C: 14-25	H:80; C:80	H:6 ; C: 1.49	H: 7; C: 3/FV		14.8m L x 2.6m Diam	5352 tubes, 19mm OD, 9.9m long tubes
P-002	Absorber WW pump	Centrifugal	2/train	SS	2478 x 1.1 t/h	47.00	80 / -10	6.00	7.00	488kW	Baseplate L = 1.728m, W =1.728m	
P-003	Rich amine pumps	Centrifugal	2/train	SS316L	1903 x 1.1 t/hr	36.00	80 / -10	10.30	11.00	677kW	Baseplate L = 5.047m, W =1.309m	
E-004	Lean/Rich exchangers	Plate and frame	6/train	SS316L	H: 1759 C: 1906 t/hr	H: 118-55; C: 36-105	140 / -10	H: 6; C: 10.3	11.00		4.6m L x 1.6m W x 4m H (x 6 per train)	

Post-Combustion Capture Scenario 3 (PFD Drawing: 64225A-DSC-00002)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
C-004	Stripper	Vertical cylinder	1/train	Vessel: SS 316 Packing: SS316	1859 t/h rich	119.00	150 / -10	0.57	2 / FV		8m ID x 40m H	
	Stripper packing	Structured Mellapak 250Y				119.00	150 / -10	0.57	2 / FV		8m ID x 20m H (3m WW section)	
E-006	Reboilers	Vertical shell & tube thermosyphon	4/train	Shell: SS316L Tube: SS316L	C 1952 t/hr	H: 139 -129°C (tubeside, stm) C: 116 - 118°C (shellside)	Tubes: 295 Shell: 150	Tubes:2.46 (stm) Shell: 0.51	Tubes: 5 / FV Shell: 2 / FV		133.9 MW 2.4m Diam x 10.3m L	4 per train. LP stm condenser. Thermosyphon recirculaton by 3m static head above bottom HX. Heat stable salts can occur. 1594 tubes, 19mm OD, 5.3m tube length
V-002	Reboiler condensate drum	Vertical drum	1/train	CS	213 t/hr	137.00	295 / -10	2.46	5/FV		2m ID x 5.5m TL (approx 17m^3)	The ability to increase set pt of LC to partially flood reboilers included to allow better control of stm to reboilers during turndown. NLL = bottom tubesheet of reboilers
P-008	Condensate return pump	Centrifugal	2/train	CS/SS316L	213 x 1.1 t/hr	137.00	295 / -10	8.30	12.4/FV	50kW	Baseplate length = 2.334m x width = 0.8318m	
P-009	Stripper WW pump	Centrifugal	1/train	SS316L	550 x 1.1 t/hr	111.00	150 / -10	4.60	7 / FV	70kW	Baseplate length = 2.489m x width = 0.8888m	
V-001	Stripper overhead receiver	Vertical drum	1/train	SS316L		40.00	150 / -10	0.49	2/FV		3.75 ID x 7.4 TL (81m^3 approx)	
E-005	Stripper condenser	Shell & Tube	2/train	Shell: SS304 Tubes: SS304	H 195t/hr: C 2598t/hr	H: 89-37; C: 14-25	H: 150; C:80	H: 0.51; C: 1.49	H: 2/FV; C:3/FV		31.5m L x 3.7m Diam	4040 tubes, 22mm OD, 26.6m long tubes
P-007	Stripper reflux pump	Centrifugal	2/train	SS316L	56 x 1.1 t/hr	30.00	150 / -10	4.00	13.3/FV	8 kW	Baseplate length = 1.454m x width = 0.5118m	
P-006	Lean amine pumps	Centrifugal (fixed speed)	2/train	22% Cr Duplex SS	1757 x 1.1 t/hr	119.00	140 / -10	6.00	8/FV	337kW	Baseplate length = 3.563m x width = 1.285m	
E-003	Lean amine cooler	Plate and frame	4/train	SS	H 1754t/hr : C 2124t/hr	H: 51 - 35; C 25 -35	140 / -10	H: 5.0; C:2.49	9.50		4L x 1.5W x 3.3 H (each)	Turndown = 48%
F-002	Upstream guard filter	Cartridge filter	1/train	CS	30	35.00	80 / -10	5.00	8.00		.6 ID x 2.5 TL	
C-003	Carbon filter	Activated carbon	1/train	CS	30	35.00	80 / -10	5.00	8.00		3.4 ID x 3.9 TL	
F-001	Downstream guard filter	Cartridge filter	1/train	CS	30	35.00	80 / -10	5.00	8.00		.9 ID x 2.9 TL	

Post-Combustion Capture Scenario 3 (PFD Drawing: 64225A-DSC-00002)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
S-002	Reclaimer Package	Vessel c/w coils	1/train	SS	12000 kg/h (batch)	232.00	300 / -10	H 29.0: C 1.0	H 35/FV : C 2.0			IP steam supply
	Amine 2 IBC heating station		1/train	CS		60.00	100 / -10	0.00			IBC: 1m^3 each	Space for 4 off IBC's
P-004	Amine 2 storage pump		1/train	SS316L		60.00	100 / -10	2.40	2.40	3.3kW		
S-001	IBC filling package		1/train	CS	2t/h					0.5kW		
P-005	Cooling Water Pumps (closed loop)	Centrifugal	3/train	CS	2124t/hr	35.00	80 / -10	4.20	9.50	200kW	Baseplate length = 1.285m x width = 1.285m	2x50% duty, 1 stand-by
E-007	Cooling Water Coolers (closed loop)	Shell & Tube	1/train	CS	H 2124t/hr : C 1987t/hr	H: 35 - 25 ; C 14-25	100 / -10	H 2.5 : C 1.49	5.00		22.4m L x 2.75m Diam	4350 tubes, 22mm OD, 18.6m long tubes
V-003	Cooling Water Expansion Vessel (closed loop)	Tank	1/train	CS		35.00	80 / -10	0.50	4.5/FV		1.8 ID x 2.6m TL (6m3 approx)	
	Amine solution tank	Storage tank	1	CS		30.00	80 / -10	0.02	0.056 / -0.006		10 ID x 15 (1178m^3 approx)	Inventory = inventory of Absorber or Stripper system.
	Amine Solution Holding Tank	Vertical, cylindrical with heating coil	1	SS 316L		30.00	80 / -10	0.02	0.056 / -0.006		15 ID x 16.2 (2800m^3 approx)	Feeds both Absorbers
	Amine solution holding tank pump	Centrifugal	1	SS	150	35.00	100 / -10	5.00	7.70	26kW		
	Amine 1 Tank	Vertical, cylindrical with heating coil	1	SS 316L		30.00	80 / -10	0.02	0.056 / -0.006		4 ID x 6 (75m^3 approx)	Heated using condensate 25 - 35 degC. N_2 blanket prevent reaction with O_2
	Amine 1 Pump	Centrifugal pump	1	SS	22	30.00	80 / -10	4.00	6.10	5kW	Baseplate length = 1.105m x width = 0.3861m	
	Amine 1 Unloading pump with tanker connection	Centrifugal pump	1	SS	22	30.00	80 / -10	4.00	6.10	5kW	Baseplate length = 1.105m x width = 0.3861m	
	Nitrogen Package	Tank/pump	1	CS		20.00	80 / -10	7.00	14.00			
	Process drain tank	Storage tank	1/train	CS			80 / -10	0.80	Full liquid		8m^3 approx	
	Process drain tank sump		1/train	Concrete		20.00	80 / -10		Full liquid			
	Process drain tank pump	Centrifugal pump	1/train	SS	50	20.00	80 / -10	0.80	5.00	5kW		
	Process drain tank sump pump	Centrifugal pump	1/train	SS	50	20.00	80 / -10	0.80	5.00	5kW		
	Amine drain tank	Storage tank	1	CS		80.00	80 / -10	0.50	Full liquid		100m^3	
	Amine drain sump pump	Centrifugal pump	1	SS	50	20.00	80 / -10	0.80	5.00	5kW		
	Towns Water Storage Tank	Vertical cylindrical	1	Lined CS		20.00	80 / -10	0.00	0.0075 / -0.0025		10m x 10m (approx 780m^3)	
	Process Water Pump	Centrifugal	1	SS316L	50	20.00	80 / -10	2.60	5.10	5kW	Baseplate length = 1.401m x width = 0.4924m	

Post-Combustion Capture Scenario 3 (PFD Drawing: 64225A-DSC-00002)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
	Tanker Loading Pump (reclaimer)	Centrifugal	1	SS 316L	30	10.00	80 / -10	0.80	3.00	5kW	Baseplate length = 1.015m x width = 0.3539m	
	Reclaimer Feed Pump	Centrifugal	1	SS 316L	25	10.00	80 / -10	3.60	5.30	5kW	Baseplate length = 1.292m x width = 0.4531m	
	Amine Unloading Area Drain Sump		1	Concrete		20.00	80 / -10	0.00	Full liquid			
	Amine Unloading Area Drain Sump Pump	Centrifugal	1	SS	50	20.00	80 / -10	0.80	5.00	5kW		
	Demin Water Tank	Tank	1	Lined CS		20.00	80 / -10	0.90	2.00		10m x 9m (approx 700m^3)	
	Demin Water Pump	Pump	3	Stainless Steel casing and impeller		20.00	80 / -10	0.80	5.20		1.7 x 0.7 x 1.4	
	Towns Water Transfer Pump	Centrifugal	3	Cast iron casing with Stainless steel impeller		20.00	80 / -10	1.00	6.00		1.8 x 1.8 x 1.8	
	Firewater Storage Tank	Tank	1	Lined CS		20.00	80 / -10		0.0075 / -0.0025		13 x 7.8	
	Firewater Pump Package	Pump	3	Carbon Steel		20.00	80 / -10		19.00		8 x 4 x 3.2	1 x diesel, 1 x electric and 1 x jockey
	Compressed Air Package	Compressor	1			20.00	80 / -10		8.70			

Post-Combustion Capture Scenario 3 CO_2 Compression (PFD Drawing: 64225A-DSC-00003)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
	CO_2 Compressor Package	Multi-stage Integrally Geared Type	1/Train	Cr Ni alloy casing/impeller	150t/hr	30 to 135	Stage 1: 150/-10 Stage 2:	Stage 1: 0 - 2 Stage 2: 2 - 7	Stage 1: 10 Stage 2: 10	14		
V-101	1st stage suction knock out drum	Vertical	1/Train	SS304	150t/hr	40	80/-10	0	10		2.9m ID x 5.0m TL (approx 33m^3)	
E-101	1st stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 150t/hr : C 394t/hr	H:132 - 30 ; C: 14-25	H:150/-10; C:80	H:2 ; C: 1.49	H: 10; C: 3/FV		7.7m L x 1.5m Diam	1222 tubes, 22mm OD, 5.5m tubes length (integrally finned - 1.6mm fin height)
V-102	2nd stage suction knock out drum	Vertical	1/Train	SS304	150t/hr	30	80/-10	2	10		2.7m ID x 4.6m TL (approx 26m^3)	
E-102	2nd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 148t/hr : C 265t/hr	H:118 - 30 ; C: 14-25	H:140/-10; C:80	H:7 ; C: 1.49	H: 10; C: 3/FV		11.35m L x 1.25m Diam	866 tubes, 22mm OD, 9.5m tubes length (integrally finned - 1.6mm fin height)
V-103	3rd stage suction knock out drum	Vertical	1/Train	SS304	148t/hr	30	80/-10	7	10		2.5m ID x 4.4m TL (approx 21m^3)	
E-103	3rd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 148t/hr : C 279t/hr	H:121 - 30 ; C: 14-25	H:140/-10; C:80	H:22 ; C: 1.49	H: 25; C: 3/FV		10.8m L x 1.3m Diam	866 tubes, 22mm OD, 8.9m tubes length (integrally finned - 1.6mm fin height)
V-104	4th stage suction knock out drum	Vertical	1/Train	SS304	148t/hr	30	80/-10	22	25		2.2m ID x 4.2mTL (approx 15m^3)	
E-104	4th stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 148t/hr : C 413t/hr	H:127 - 30 ; C: 14-25	H:150/-10; C:80	H:64 ; C: 1.49	H: 76; C: 3/FV		12.11m L x 1.6m Diam	1282 tubes, 22mm OD, 9.6m tubes length (integrally finned - 1.6mm fin height)
V-105	5th stage suction knock drum	Vertical	1/Train	SS304	148t/hr	30.00	80/-10	64.00	76		1.8m ID x 4.0m TL (approx 11m^3)	
TEG-101	TEG Dehydration Package		1/Train		148t/hr	30.00	150/-10	64.00	76			Less than 500 ppm H2O
	CO_2 Analyser House		1									
E-105	5th stage discharge cooler		1/Train	Shell: SS304 Tube: SS304	H: 147t/hr : C 500t/hr	H:75 - 30 ; C: 14-25	H:100/-89; C:80	H:110 ; C: 1.49	H: 125; C: 3/FV		16.8m L x 1.8m Diam	1554 tubes, 22mm OD, 13.8m tubes length (integrally finned - 1.6mm fin height)
	Condensate return pump		1Train	SS304	5t/hr	30.00	80/-10	5.00	12		1kW	
	Permanent Universal Pig Launcher/Receiver		1	CS		30.00	80/-20	110.00				
	Flow metering and analyser package		1			30.00	80/-20	110.00				

APPENDIX B-3: EQUIPMENT LIST SCENARIO 4

Post Combustion Capture Scenario 4 (PFD Drawing: 64225A-DSC-00007)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
	Flue gas ducting to Fan FA-001 / DCC1	Square	1/train	CS	2400 t/h	92.80	150 / -10	0.00	0.10		6m x 6m	Estimated length 83m
	Flue gas ducting to Fan FA-002 / DCC2	Square	1/train	CS	1206t/hr	92.80	150 / -10	0.00	0.10		4.2m x 4.2m	Estimated length 30m
	Recirculation ducting	Square	1/train	CS	1206 t/hr	92.80	150 / -10	0.00	0.10		4.2m x 4.2m	Estimated length 100m
	Flue gas ducting DCC to absorber	Square	1/train	CS	1206 t/h	33.10	80 / -10	0.05	0.10		4.2m x 4.2m	Esimated length 27m
	Flue gas ducting from absorber	Square	1/train	CS	1010 t/hr	35.00	80 / -10	0.01	0.10		3.75m x 3.75m	Estimated length 3m
	GRP Stack located on top of absorber & condensate cooler	Cylindrical	1/train	GRP	1010 t/hr	67.20	100 / -10	0.01	0.10		3.75m ID	Estimated height 12m
FA-001	Flue Gas Fan	Axial	1/train	CS	1194 x 1.1 t/hr	103.80	150 / -10	0.10	0.30	4.4		∆P = 101.8mbar
FA-002	Flue Gas Recirculation Fan	Axial	1/train	CS	1206 x 1.1 t/hr	96.60	150 / -10	0.10	0.30	1.7		∆P = 40mbar
C-001	DCC 1 (Direct Contact Cooler)	Vertical column	1/train	CS with lining. SS316L packing and internals	1194 t/hr	80.00	150 / -10	0.10	0.30			Demister, distribution system, packed bed and bed support. Scale down Scenario 3 xsect area by 1.78
	DCC 1 Packing	Structured Mellapak 250Y	1/train	SS316L		80.00	150 / -10	0.10	0.30			
	DCC 1 Distributor / Collector		1/train	SS316L		80.00	150 / -10	0.10	0.30			
C-005	DCC 2 (Recirculation Direct Contact Cooler)	Vertical column	1/train	CS with lining. SS316L packing and internals	1206 t/hr	80.00	150 / -10	0.10	0.30			Demister, distribution system, packed bed and bed support. Scale down Scenario 3 xsect area by 1.78
	DCC 2 Packing	Structured Mellapak 250Y	1/train	SS316L		80.00	150 / -10	0.10	0.30			
	DCC 2 Distributor / Collector		1/train	SS316L		80.00	150 / -10	0.10	0.30			
P-001	DCC1 Pump	Centrifugal	2/train	SS316L	2002 x 1.1 t/hr	51.80	80 / -10	4.99	7.00	0.7	Baseplate L = 1.923m; W = 1.923m	
E-001	DCC1 Cooler	Plate and frame	3/train	Titanium	H: 1961 t/hr C: 3898 t/hr	H: 51.8-30; C: 14-25	80 / -10	H: 4.99; C: 1.99	7.00			Duty 49.5MW
P-010	DCC2 Pump	Centrifugal	2/train	SS316L	4841 t/hr	28	50	3.00	5.00	0.34	Baseplate L: 1.596m; W: 1.596m	
E-008	DCC2 Cooler	Plate and frame	3/train	SS304	4786 t/hr	H: 28.34-17.21 C: 14.41-25.45	H: 80; C: 80	H: 2 C: 2.33	5.00			
C-002	Absorber	Rectangular column	1/train	Concrete with polypropylene lining. SS316 structured packing and internals	1153 t/hr	33.00	80 / -10	0.05	0.10			Demister, distribution system, packed bed and bed support
	Absorber packing	Structured Mellapak 250Y	1/train	SS316L		52.00	80 / -10	0.05	0.10			

Post Combustion Capture Scenario 4 (PFD Drawing: 64225A-DSC-00007)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
E-002	Absorber WW cooler	Shell & Tube	1/train	Shell: SS316 Tubes: SS316	H: 1846t/hr C: 5276t/hr	H: 56.2-25 C: 14-25	H: 80; C: 80	H: 3.99 C: 1.99	H: 6 C: 3		13.82m L x 2.56m Diam.	Duty 66.7MW 5175 tubes, 19.05mm OD, 9.532m tube length
P-002	Absorber WW pump	Centrifugal	2/train	SS316L	1846 x 1.1 t/hr	56.10	80 / -10	3.99	6.00	0.24	Baseplate L = 1.445m; W = 1.445m	
P-003	Rich amine pumps	Centrifugal	2/train	SS316L	1924 x 1.1 t/hr	38.10	80 / -10	10.30	11.00	0.68	Baseplate L = 5.063m; W: 1.313m	
E-004	Lean / Rich exchangers	Plate and frame	6/train	SS316L	H: 1778 t/hr C: 1924t /hr	H: 117.7 - 51.9: C: 38.1 - 105	140 / -10	H: 6; C: 10.3	13.00			Duty 107.1MW
C-004	Stripper	Vertical column	1/train	Vessel: SS316L Packing: SS316L	1924 t/hr	118.00	150 / -10	0.56	2 / FV			
	Stripper packing	Structured Mellapak 250Y	1/train	SS316L		118.00	150 / -10	0.56	2 / FV			
E-006	Reboilers	Vertical shell & tube thermosyphon	4/train	SS316L	1971 t/hr	H: 140.2 - 129: C: 116 - 118	H: 295; C: 150	H: 2.55; C: 0.56	5 / FV		2.3m x 10.1m L	4 per train. LP stm condenser. Thermosyphon recirculaton by 3m static head above bottom HX. Heat stable salts can occur. Duty 123.0MW 1458 tubes, 19mm OD, 5.3m tube length
V-002	Reboiler condensate drum	Vertical drum	1/train	CS	200 t/hr	129.00	295 / -10	2.46	5 / FV		2m ID x 5.5m TL (approx 17m^3)	
P-008	Condensate return pump	Centrifugal	1/train	SS316L	200 x 1.1 t/hr	129.00	295 / -10	8.30	12.4 / FV	44kW	Baseplate L= 2.298m; W = 0.8188m	
P-009	Stripper WW Pump	Centrifugal	1/train	SS316L	550 x 1.1 t/hr	111.00	150 / -10	4.60	7 / FV	70kW	Baseplate length = 2.489m x width = 0.8888m	
V-001	Stripper overhead receiver	Vertical drum	1/train	SS316L	182.4 t/hr	37.30	150 / -10	0.51	2 / FV		3.75 ID x 7.4 TL (81m^3 approx)	
E-005	Stripper condenser	Shell & Tube	2/train	Shell: SS304 Tubes: SS304	H: 188 t/hr C: 2575 t/hr	H: 88 - 39 C: 14-25	H: 150 C:80	H: 0.51 C: 1.49	3 / FV		27.91m L x 2.639m Diam	Duty 33.7MW 4000 tubes, 22mm OD, 24.13m tube length
P-007	Stripper reflux pump	Centrifugal	2/train	SS316L	36.3 x 1.1 t/hr	37.30	150 / -10	5.80	7 / FV	9kW	Baseplate L = 1.323m; W = 0.4645	
P-006	Lean amine pump	Centrifugal	2/train	22% Cr Duples SS	1778 x 1.1 t/hr	118.00	150 / -10	6.00	8 / FV	337kW	Baseplate length = 3.572m x width = 1.288m	
E-003	Lean amine cooler	Plate & Frame	4/train	SS316L	H: 1778 t/hr: C: 2229 t/hr	H: 52-35; C: 25-35	150 / -10	H: 5.3; C: 1.49	7.00			Duty 26.6MW
F-002	Upstream guard filter	Cartridge filter	1/train	CS	30	35.00	80 / -10	5.00	8.00		.6 ID x 2.5 TL	

Post Combustion Capture Scenario 4 (PFD Drawing: 64225A-DSC-00007)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
C-003	Carbon filter	Activated carbon	1/train	CS	30	35.00	80 / -10	5.00	8.00		3.4 ID x 3.9 TL	
F-001	Downstream guard filter	Cartridge filter	1/train	CS	30	35.00	80 / -10	5.00	8.00		.9 ID x 2.9 TL	
S-002	Reclaimer Package	Vessel c/w coils	1/train	SS	12000 kg/h (batch)	232.00	300 / -10	H 29.0: C 1.0	H 35 / FV : C 2.0			IP steam supply
	Amine 2 IBC heating station		1/train	CS		60.00	100 / -10	0.00			IBC: 1m^3 each	Space for 4 off IBC's
P-004	Amine 2 storage pump		1/train	SS316L		60.00	100 / -10	2.40	2.40	3.3kW		
S-001	IBC filling package		1/train	CS								
P-005	Cooling Water Pumps (closed loop)	Centrifugal	3/train	CS	2229 t/hr	35.00	80 / -10	3.20	6.00	200kW/2pumps	Baseplate length = 1.299m x width = 1.299m	2x50% duty, 1 stand-by
E-007	Cooling water coolers (closed loop)	Shell & Tube	1/train	CS	H: 2229 t/hr; C: 2069 t/hr	H: 35-25; C: 14-25	80 / -10	H: 3.2; C: 1.99	5.00		24.37m L x 2.8m Diam	Duty 26.7MW 4526 tubes, 22mm OD, 20.3m tube length
V-003	Cooling water expansion vessel (closed loop)	Tank	1	CS		35.00	80 / -10	0.50	5.00		1.8 ID x 2.6m TL (6m3 approx)	
E-009	Flue-gas reheater / condensate cooler	Finned Tube	1/train	Tube: CS Fin: Aluminium	H: 200 t/hr; C: 1010 t/hr	H: 129-88; C: 35-67.2	150 / -10	H: 0.1; C: 0.01	2.00		11.11m L x 12.37m W x 0.65m H	1068 finned tubes, 1" diameter, 10.31m long. Duty 14.8MW
	Amine solution tank	Storage tank	1	CS		30.00	80 / -10	0.02	0.056 / -0.006		10 ID x 15 (1178m^3 approx)	Inventory = inventory of Absorber or Stripper system.
	Amine Solution Holding Tank	Vertical, cylindrical with heating coil	1	SS 316L		30.00	80 / -10	0.02	0.056 / -0.006		15 ID x 16.2 (2800m^3 approx)	Feeds both Absorbers
	Amine solution holding tank pump	Centrifugal	1	SS	150	35.00	100 / -10	5.00	7.70	26kW		
	Amine 1 Tank	Vertical, cylindrical with heating coil	1	SS 316L		30.00	80 / -10	0.02	0.056 / -0.006		4 ID x 6 (75m^3 approx)	Heated using condensate 25 - 35 degC. N_2 blanket prevent reaction with O_2
	Amine 1 Pump	Centrifugal pump	1	SS	22	30.00	80 / -10	4.00	6.10	5kW	Baseplate length = 1.105m x width = 0.3861m	
	Amine 1 Unloading pump with tanker connection	Centrifugal pump	1	SS	22	30.00	80 / -10	4.00	6.10	5kW	Baseplate length = 1.105m x width = 0.3861m	
	Nitrogen Package	Tank/pump	1				80 / -10		14.00			
	Process drain tank	Storage tank	1/train	CS			80 / -10		Full liquid		8m^3 approx	
	Process drain tank sump		1/train	Concrete		20.00	80 / -10		Full liquid			
	Process drain tank pump	Centrifugal pump	1/train	SS	50	20.00	80 / -10		5.00	5kW		
	Process drain tank sump pump	Centrifugal pump	1/train	SS	50	20.00	80 / -10		5.00	5kW		
	Amine drain tank	Storage tank	1	CS		80.00	80 / -10	0.50	Full liquid		100m3	Volume = c. half WW volume
	Amine drain sump pump	Centrifugal pump	1	SS	50	20.00	80 / -10	0.80	5.00	5kW		
	Process Water Tank	Vertical,cylindrical	1	Lined CS		20.00	80 / -10	0.00	0.0075 / -0.0025		10m x 10m	

Post Combustion Capture Scenario 4 (PFD Drawing: 64225A-DSC-00007)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (^{o}C)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
	Process Water Pump	Centrifugal	1	CS / SS316L	50	20.00	80 / -10	2.60	5.10	5kW	Baseplate length = 1.401m x width = 0.4924m	
	Tanker Loading Pump (reclaimer)		1	SS 316L	30	10.00	80 / -10	0.80	3.00	5kW	Baseplate length = 1.015m x width = 0.3539m	
	Reclaimer Feed Pump	Centrifugal	1	SS 316L	25	10.00	80 / -10	3.60	5.30	5kW	Baseplate length = 1.292m x width = 0.4531m	
	Amine Unloading Area Drain Sump		1	Concrete		20.00	80 / -10	0.00	Full liquid			
	Amine Unloading Area Drain Sump Pump	Centrifugal	1	SS	50	20.00	80 / -10	2.60	5.10	5kW		
	Demin Water Tank	Tank	1	Lined CS		20.00	80 / -10		2.00		10m x 9m (approx $700m^3$)	
	Demin Water Pump	Pump	1	Stainless Steel casing and impeller		20.00	80 / -10	0.80	5.20		1.7 x 0.7 x 1.4	
	Towns Water Transfer Pump		1	Cast iron casing with Stainless steel impeller		20.00	80 / -10	1.00	6.00		1.8 x 1.8 x 1.8	
	Firewater Storage Tank	Tank	1	Lined CS		20.00	80 / -10		0.0075 / -0.0025		13 x 7.8	
	Firewater Pump Package	Pump	1	Carbon Steel		20.00	80 / -10		19.00		8 x 4 x 3.2	1 x diesel, 1 x electric and 1 x jockey
	Compressed Air Package	Compressor	1			20.00	80 / -10		8.70			

Post Combustion Capture Scenario 4 CO_2 Compression (PFD Drawing: 64225A-DSC-00003)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C) Normal Op	Temperature (°C) Mech Des	Pressure (Barg) Normal Op	Pressure (Barg) Mech Des	Electric Power (MW)	IEA Sizing (MEA)	Comments
	CO_2 Compressor Package	Multi-stage Integrally Geared Type	1/Train	Cr Ni alloy casing / impeller	146.1 t/hr	37.8 to 135	Stage 1: 150/-10 Stage 2: 140 / -10 Stage 3: 140 / -10 Stage 4: 150 / -10 Stage 5: 100 / -10	Stage 1: 0 - 2 Stage 2: 2 - 7 Stage 3: 7- 22 Stage 4: 22 - 64 Stage 5: 64 - 110	Stage 1: 10 Stage 2: 10 Stage 3: 25 Stage 4: 76 Stage 5: 125	13.5		
V-101	1st stage suction knock out drum	Vertical	1/Train	SS304	146.1 t/hr	37.80	80 /-10	0.06	10.00		2.9m ID x 5.0m TL (approx 33m^3)	
E-101	1st stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 146.1 t/hr; C: 408t/hr	H: 132-30; C: 14.4-24.9	H:150 /-10; C:80	H: 2.00; C: 1.49	H: 10; C: 3/FV		7.25m L x 1.5m Diam	1268 tubes, 22mm OD, 5.1m tubes length (integrally finned - 1.6mm fin height)
V-102	2nd stage suction knock out drum	Vertical	1/Train	SS304	144.2 t/hr	30.00	80 /-10	2.00	10.00		2.7m ID x 4.6m TL (approx 26m^3)	
E-102	2nd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 144.2 t/hr; C: 272.0 t/hr	H: 117.7-30; C: 14.4-24.9	H:140 /-10; C:80	H: 7.00; C: 1.49	H: 10; C: 3/FV		11.4m L x 1.23m Diam	846 tubes, 22mm OD, 9.6m tubes length (integrally finned - 1.6mm fin height)
V-103	3rd stage suction knock out drum	Vertical	1/Train	SS304	144.2 t/hr	30.00	80 /-10	7.32	10.00		2.5m ID x 4.4m TL (approx 21m^3)	
E-103	3rd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 143.7 t/hr; C: 276.9 t/hr	H: 120.3-30; C: 14.4-24.8	H:140 /-10; C:80	H: 22.00; C: 1.49	H: 25; C: 3/FV		10.3m L x 1.25m Diam	860 tubes, 22mm OD, 8.5m long tubes (integrally finned - 1.6mm fin height)
V-104	4th stage suction knock out drum	Vertical	1/Train	SS304	143.7 t/hr	30.00	80 /-10	22.22	25.00		2.2m ID x 4.2mTL (approx 15m^3)	
E-104	4th stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 143.7 t/hr; C: 415.3 t/hr	H: 127.2-30; C: 14.4-24.8	H:150 /-10; C:80	H: 64.00; C: 1.49	H: 76; C: 3/FV		11.5m L x 1.6m Diam	1290 tubes, 22mm OD, 9m long tubes (integrally finned - 1.6mm fin height)
V-105	5th stage suction knock drum	Vertical	1/Train	SS304	143.7 t/hr	30.00	80 /-10	63.95	76.00		1.8m ID x 4.0m TL (approx 11m^3)	
TEG-101	TEG Dehydration Package		1/Train		143.7 t/hr	30.00	150 /-10	63.95	76.00			Less than 500 ppm H2O
	CO_2 Analyser House		1									
E-105	5th stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 143.5 t/hr; C: 488.3t/hr	H: 74.8-30; C: 14.4-25	H:100 /-89; C:80	H: 110.00; C: 1.49	H: 125; C: 3/FV		16.65m L x 1.8m Diam	1516 tubes, 22mm OD, 13.7m long tubes (integrally finned - 1.6mm fin height)
	Condensate return pump		1Train	SS304	2.4 t/hr	30.00	80 /-10	5.00	5.00	0.7kW	1kW	

Post Combustion Capture Scenario 4 CO_2 Compression (PFD Drawing: 64225A-DSC-00003)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Electric Power (MW)	IEA Sizing (MEA)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
	Permanent Universal Pig Launcher/Receiver		1	CS	148 t/hr		80 /-20					
	Flow metering and analyser package		1		148 t/hr		80 /-20					

APPENDIX B-4: EQUIPMENT LIST SCENARIO 5

Pre-Combustion Capture Scenario 5 (PFD Drawing: 64225A-DSC-00005)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Power (MWe)	IEA Sizing	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
F-001	Furnace Pre-Heater	Vertical Furnace	1/train	Cr-Mo steel furnace body with refractory lining at combustion zone	Flue Gas Flowrate: 101t/h	2030	2500/-10	0.1	1.0/FV		L = 10m, W = 10m, H = 30m	Capacity: 73MWth
E-001	Furnace Pre-Heater 1	Coil tubes	1/train	2.25Cr-1.0Mo tubes	C: 219t/h H: 101t/h	C: 298/550 H: 2030/1046		C: 44.8 H: 0.09				Duty: 40.7MWth Pre-Reformer Feed Furnace Pre-Heater
E-002	Furnace Pre-Heater 2	Coil tubes	1/train	2.25Cr-1.0Mo tubes	C: 344t/h H: 101t/h	C: 332/540 H: 1046/467		C: 46 H: 0.08				Duty: 21.5MWth Reformer Process Air Furnace Pre-Heater
E-003	Furnace Pre-Heater 3	Coil tubes	1/train	1Cr-0.5Mo tubes	C: 74t/h H:101t/h	C: 230/341 H: 467/264		C: 45.4 H: 0.07				Duty: 6.9MWth Hydrogenator Feed Furnace Pre Heater
E-004	Furnace Pre-Heater 4	Coil tubes	1/train	Carbon Steel tubes	C: 91t/h H:101t/h	C: 19/200 H: 264/121		C: 0.1 H: 0.06				Duty: 4.7MWth Combustion Air Pre-Heater
E-005	Not Used											
PRS-002	Pressure Reducing Station 2	Pressure Regulating Valves	2/train	Carbon Steel	4t/h	In/Out: 60/32	100/-10	In/Out: 68.7/0.99	77.00		Pipe Schedule80, Inlet OD=60.33mm, Outlet OD = 219.1mm Valve size 2" & 4"	Natural Gas to Furnace Pre-Heater
PRS-003	Pressure Reducing Station 3	Pressure Regulating Valves	2/train	Carbon Steel	6t/h	In/Out: 78/77.6	125/-10	In/Out: 34.0/0.99	38.00		Pipe Schedule40, Inlet OD=88.9mm, Outlet OD= 273.1mm Valve size 6"	Hydrogen/Nitrogen to Furnace Pre-Heater
FA-001	Combustion Air Fan	Centrifugal Blower	1/train	Carbon Steel	91t/h	In/Out: 9/19.1	100/-10	In/Out: 0.0/0.1	1.0/FV	0.286		Part of F-001
K-001	Not Used											
E-006	Not Used											
K-002	GT Process Air Booster Compressor	Centrifugal	1/train	1.0Cr-0.5Mo	344t/h	In/Out: 130/332	435/-10	In/Out: 15/46.0	50.00	20.1	Comp: L = 5.5m, W = 3m Motor: L = 6.2m, W = 3m Lube Oil System: L = 6m, W = 3.2m	Electric Motor Rating 20MW, 4 poles
E-023	Process Air Cooler 1	Shell&Tube	1/train	Shell: 1.0Cr-0.5Mo; Tubes: CS	C: 144t/h H: 344t/h	C: 265/295 H: 396/366	C: 375/-10 H: 450/-10	C: 49.4 H: 16.9	55.00		D = 1.376m, W = 8.822m, Total external heat transfer area = 181 m2 Heat transfer coefficient = 275.7 W/m2.C	Duty: 3.04MWth Process Steam Superheater
PRS-004	Pressure Reducing Station 4	Pressure Regulating Valves	2/train	Carbon Steel	144t/h	In/Out: 395/292.7	375/-10	In/Out: 49.1/47.0	55.00		Pipe Schedule60, Inlet OD=273.1mm, Outlet=273.1mm Valve Size: 6"	Process Steam PRS
E-024	Process Air Cooler 2	Shell&Tube	1/train	Shell: 1.0Cr-0.5Mo; Tubes: CS	C: 190t/h H: 344t/h	C: 265/287 H: 366/336	C: 360/-10 H: 460/-10	C: 49.4 H: 16.6	55.00		D = 1.682m, W = 8.3m, Total external heat transfer area = 335m2 Heat transfer coefficient = 297.4 W/m2.C	Duty: 3.0MWth IP Steam Export Superheater
E-025	Process Air Cooler 3	Package Boiler	1/train	Vendor to Advise	C: 28t/h H: 344t/h	C: 118/164 H: 336/148	425/-10	C: 5.0 H: 16.3	16.00		D = 3.278m, W = 11.98m, Total external heat transfer area = 1,030 m2 Heat transfer coefficient = 410.4 W/m2.C	Duty: 1.3 + 17.4MWth LP Steam Generator
E-026	Process Air Cooler 4	Shell&Tube	1/train	Carbon Steel	C: 122.7t/h H: 344t/h	C: 14.4/25 H: 148/130	C: 35/-10 H: 150/-10	C: 4 H: 15.7	15.00		D = 0.9508m, W = 4.918m, Total external heat transfer area = 25.37 m2 Heat transfer coefficient = 447.4 W/m2.C	Duty: 1.8MWth Cooling Water

Pre-Combustion Capture Scenario 5 (PFD Drawing: 64225A-DSC-00005)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (^oC)		Pressure (Barg)		Power (MWe)	IEA Sizing	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
E-027	Process NG Letdown Station Heater	Shell&Tube	1/train	Carbon Steel	C: 74t/h H: 55t/h	C: 9/80 H: 140/89	C: 50/-10 H: 150/-10	C: 69 H: 3.7	76.00		D = 0.4575m, W = 4.945m, Total external heat transfer area = 109 m2 Heat transfer coefficient = 507.63 W/m2.C	Duty: 3.8MWth LP Condensate
E-028	Furnace NG Letdown Station Heater	Shell&Tube	1/train	Carbon Steel	C: 4t/h H: 55t/h	C: 9/60 H: 89/87	C: 100/-10 H: 150/-10	C: 69 H: 3.2	76.00		D = 0.3302m, W = 1.59m Total external heat transfer area = 7.813 m2 Heat transfer coefficient = 326 W/m2.C	Duty: 0.2MWth LP Condensate
PRS-001	Pressure Reducing Station 1	Pressure Regulating Valves	2/train	Carbon Steel	74t/h	In/Out: 80/73.2	50/-10	In/Out: 68.7/47	76.00		Schedule80, Inlet OD=168.3mm, Outlet OD=168.3mm Valve Size: 4"	Natural Gas to Process
E-007	Not Used											
E-008	Hydrogenator Feed LP Steam Pre-Heater	Shell&Tube	1/train	CS Shell (Gas) SS Tube (Steam)	C: 74t/h H: 2t/h	C: 73/99 H: 164/120	C: 85/-10 H: 205/-10	C: 46 H: 4.4	51.00		D =0.3239m, W = 4.434m, Total external heat transfer area = 38.41 m2 Heat transfer coefficient = 465.1 W/m2.C	Duty: 1.3MWth Area: 66.7m2, U=300W/m2K
E-009	Hydrogenator Feed IP Steam Pre-Heater	Shell&Tube	1/train	CS Shell (Gas) SS Tube (Steam)	C: 74t/h H: 15t/h	C: 99/231 H: 265/260	C: 300/-10 H: 330/-10	C: 46 H: 49.4	55.00		D =0.6232m, W = 4.3m Total external heat transfer area = 172 m2 Heat transfer coefficient = 478.3 W/m2.C	Duty: 72MWth Area: 378m2, U=300W/m2K
K-003	H2/N2 Gas Compressor	Centrifugal	1/train	Carbon Steel	0.5t/h	In/Out: 78/112	170/-10	In/Out: 36.1/46	55.00	0.01		Single-Stage Compression
C-001	Hydrogenator	Reactor	1/train	External: CS Internals: SS	74t/h	341	430/-10	In/Out: 45.3/44.8	50.00			
C-002A/B	Desulphuriser	Reactor	2/train	External: CS Internals: SS	37t/h	341	430/-10	44.8	50.00			
E-010	Not Used											
R-001	Pre-Reformer	Reactor	1/train	External: SS304 Internals: SS	219t/h	In/Out: 550/547	690/-10	In/Out: 44.5/42.6	50.00			
R-002	Autothermal Reformer	Reactor	1/train	External: DIN17135 CS Internal: Refractory Brickwork at combustion zone	562t/h	Combustion Zone: 1335	1700/-10	In/Out: 43/41	47.50		Dia: 6m Pack Height: 10m Total Height: 65m	
E-011	Not Used											
E-012	Syngas Cooler 1	Convective Shell&Tube	1/train	Shell: CS Tube: Alloy Steel	C: 339t/h H: 562t/h	C: 259/265 H: 912/348	C: 330/-10 H: 1200/-10	C: 49.9 H: 40.6	55.00		D = 2.667, W =20.03m, Total external heat transfer area = 1284.1 m2 Heat transfer coefficient = 466.4 W/m2.C	IP Steam Generator

Pre-Combustion Capture Scenario 5 (PFD Drawing: 64225A-DSC-00005)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C) Normal Op	Temperature (°C) Mech Des	Pressure (Barg) Normal Op	Pressure (Barg) Mech Des	Power (MWe)	IEA Sizing	Comments
D-001	IP Steam Drum	Horizontal	1/train	Carbon Steel	339t/h 611Am3/h	Sat Temp: 263	340/-10	49.9	56.00		D = 4.464m, W = 15.83m Total external heat transfer area = 985 m2 Heat transfer coefficient = 477.3 W/m2.C	Part of IP Steam Generator
R-003	High Temperature Shift Reactor	Reactor	1/train	1.0Cr-0.5Mo	562t/h	In/Out: 348/419	525/-10	In/Out: 40.3/39.6	45.00		ID: 8.4m T/T: 3.1m Total Height:7.75m	
E-013	Syngas Cooler 2	Shell&Tube	1/train	1.0Cr-0.5Mo	C: 324t/h H: 562t/h	C: 150/263 H: 419/229	C: 330/-10 H: 525/-10	C: 50.5 H: 39.6	56.00		D =0.8155m, W = 19.92m Total external heat transfer area = 1,390 m2 Heat transfer coefficient = 280.6 W/m2.C	Duty: 53.2MWth IP Boiler Feedwater Heater
R-004	Low Temperature Shift Reactor	Reactor	1/train	1.25Cr-0.5Mo	562t/h	In/Out: 229/251	315/-10	In/Out: 39.4/38.1	45.00		ID: 11.2m T/T: 2.74m Total Height: 6.5m	
E-014	LT Shift Reactor Product Cooler 1	Convective Shell&Tube	1/train	Shell: CS Tube: CS	C: 26.5t/h H: 562t/h	C: 154/164 H: 251/192	315/-10	C: 4.7 H: 38.1	42.00		D =1.443m, W = 5.023m Total external heat transfer area = 4.884 m2 Heat transfer coefficient = 170.1 W/m2.C	Duty: 16.4MWth LP Steam Generator
D-002	LP Steam Drum	Horizontal	1/train	Carbon Steel	26.5t/h Liquid flowrate: 39.6Am3/h	Sat Temp: 155	195/-10	4.4	5.00		D =3.608m, W = 13.06m Total external heat transfer area = 577 m2 Heat transfer coefficient = 478.4 W/m2.C	Part of LP Steam Generator
E-015	LT Shift Reactor Product Cooler 2	Shell&Tube	1/train	Carbon Steel	C: 26.5t/h H: 562t/h	C: 118/154 H: 192/187	250/-10	C: 5.2 H: 37.8	42.00		D =1.121m, W = 5.909m Total external heat transfer area = 50.64 m2 Heat transfer coefficient = 427.3 W/m2.C	Duty: 1.3MWth LP Boiler Feedwater Heater
E-016	LT Shift Reactor Product Cooler 3	Shell&Tube	1/train	Carbon Steel	C: 324t/h H: 562t/h	C: 19.6/150 H: 187/120	250/-10	C: 51.0 H: 37.5	57.00		D =1.439m, W = 15.05m Total external heat transfer area = 1,510 m2 Heat transfer coefficient = 498.7W/m2.C	Duty: 57MWth IP Boiler Feedwater Heater
E-017	LT Shift Reactor Product Cooler 4	Shell&Tube	1/train	Carbon Steel	C: 5000t/h H: 562t/h	C: 14.4/25 H: 120/20	150/-10	C: 4.0 H: 37.2	41.00		D =2.676m, W = 20.08m Total external heat transfer area = 5,830 m2 Heat transfer coefficient = 327.3 W/m2.C	Duty: 44MWth Cooling Water
D-003	Knock-Out Drum	Vertical	1/train	Carbon Steel	Inlet Flow: 562t/h	20	50/-10	36.9	41.00		ID = 7m, H = 5.25m	Knocked out: Condensate 87.9t/h, 94.8Am3/h
C-003	CO_2 Absorber	Vertical	1/train	Column: CS Internals: CS	Liquid Feed: 5400t/h Gas Feed: 510t/h	Top: -5.0 Bottom: 2	10/-10	Top: 36.31 Bottom: 36.81	41.00		ID: 7.3m	

Pre-Combustion Capture Scenario 5 (PFD Drawing: 64225A-DSC-00005)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C) Normal Op	Temperature (°C) Mech Des	Pressure (Barg) Normal Op	Pressure (Barg) Mech Des	Power (MWe)	IEA Sizing	Comments
	Absorber packing	Structured Mellapak 250Y	1/train	SS316L							No. Stages: 20	Sulzer Melapak 250Y Structured Packing
E-029	GT Fuel Heater	Shell&Tube	1/train	Carbon Steel	C: 303t/h H: 23t/h	C: -5/78 H: 164/153	C: 125/-10 H: 205/-10	C: 36.3 H: 4.0	40.00		D = 2.056m, W = 5.601m, Total external heat transfer area = 156 m2 Heat transfer coefficient = 798.1 W/m2.C	Duty: 14.3MWth LP Steam
D-004	Flash Drum 1	Vertical	1/train	Carbon Steel	Inlet Liquid: 5607t/h, 5224Am3/h Gas Out (Top): 35.9t/h, 3102Am3/h Liquid Out (Bottom): 5571t/h, 5177Am3/h	In/Out: 2/0.1	10/-10	In/Out: 36.8/8.0	40.00		ID = 12.5m, H = 9.375m	
D-005	Flash Drum 2	Vertical	1/train	Carbon Steel	Inlet Liquid: 4545t/h, 4233Am3/h Gas Out (Top): 125.8t/h, 43104Am3/h Liquid Out (Bottom): 4419t/h, 4082Am3/h	In/Out: 1.8 / -4.3	10/-10	In/Out: 8.0/0.5	9.00		ID = 10.5m, H = 7.9m	
E-018	Lean Solvent Cooler	Shell&Tube	3/train	Carbon Steel Frame / Hastelloy C-276 Plates	C: 5454t/h H: 5400t/h	C: -4.6/2.5 H: 9.2/0.8	C: 10/-10 H: 10/-10	C: 0.5 H: 37.2	41.00		D = 5.242m, W = 64.19m, Total external heat transfer area = 84,900 m2 Heat transfer coefficient = 63.16 W/m2.C	Duty: 23.9MWth
E-019	Semi-Lean Solvent Heater	Shell&Tube	1/train	Carbon Steel	C: 5454t/h H: 30t/h	C: 2.5/8.5 H: 173/110	C: 10/-10 H: 205/-10	C: -0.013 H: 4	5.00/FV		D = 1.042m, W = 4.377m Total external heat transfer area = 200m2 Heat transfer coefficient = 609.2 W/m2.C	Duty: 19.1MWth LP Steam
E-020	Lean Solvent Chiller	Package Absorption Chiller	1/train	Vendor package	5400t/h	In/Out: 0.8/-10	10/-12.5	In/Out: 36.7/36.2	41.00	VTA	L = 20m, W = 14.9m	Duty: 29.8MWth Package Chiller
D-006	Flash Drum 3	Vertical	1/train	Carbon Steel	Inlet Liquid: 5454t/h, 43296Am3/h Gas Out (Top): 53.7t/h, 47767Am3/h Liquid Out (Bottom): 5400t/h, 5052Am3/h	In/Out: 8.5/8.4	10/-10	In/Out: -0.3/-0.4	1.00/FV		ID = 12.4m, H = 9.3m	
P-001	Lean Solvent Pump	Multistage Centrifugal Fixed RPM	2/train	Carbon Steel	5400t/h	In/Out:8.4/9.2	7.5/-10	In/Out: 0.4/37.2	40.00/FV	6.14	Base Plate Size: L = 5.549m, W = 2.025m	Pump suction under vacuum (2 x100%)
K-004	CO_2 Absorber Gas Recycle Compressor	Centrifugal	1/train	Carbon Steel	35.9t/h	In/Out: 0.1/109.4	135/-10	In/Out: 8/37.8	42.00	1.986		Two-Stage Compression
E-021	CO2 Absorber Gas Recycle Compressor Inter-Cooler	Shell&Tube	1/train	Carbon Steel	C: 78.1t/h H: 35.9t/h	C: 14.4/25 H: 88/30	C: 35/-10 H: 110/-10	C: 4 H: 19	21.00		D = 0.6581m, W = 4.152m, Total external heat transfer area = 56.98 m2 Heat transfer coefficient = 370.5W/m2.C	Duty: 0.7MWth

Pre-Combustion Capture Scenario 5 (PFD Drawing: 64225A-DSC-00005)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Power (MWe)	IEA Sizing	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
E-022	CO_2 Absorber Gas Recycle Compressor Cooler	Shell&Tube	1/train	Carbon Steel	C: 127t/h H: 35.9t/h	C: 14.4/25 H: 109/20	C: 35/-10 H: 135/-10	C: 4 H: 37.8	42.00		D = 0.5876m, W = 5.654m Total external heat transfer area = 83.63 m2 Heat transfer coefficient = 403.3 W/m2.C	Duty: 1.1MWth Cooling Water
K-005	Flash Drum 3 CO_2 Booster Compressor	Centrifugal	1/train	Casing: CS Impeller: SS	53.7t/h	In/Out: 8/97.6	120/-10	In/Out: -0.4/0.49	1.0/FV	1.2	L = 6.25m x W = 3m x H = 2.75m	Single-Stage Compression
	CO_2 Vent	Stack	1/plant	Carbon Steel	166.5t/hr	22	80/-10	0.4	10			
	Flare Stack	Guy-supported	1/plant	Carbon Steel		100	125/-10	36.3	40.00		24" diameter, 70m H	
	Selexol Storage Tank	Storage tank	1/plant	Carbon Steel		30.00	80 / -10	0.02	0.056 / -0.006		2600m^3	Sized for liquid inventory of CO_2 Absorber and Flash Drums D-004, D-005, and D-006
CT-001	Cooling Tower	Mechanical	1/train	Concrete	CW: 14086t/h	In/Out: 14.4/25	35/-10	4.00	21.00	2.98	11 Cells, W: 16.18m x L: 177.98m	Includes abs chiller CW: 6558 t/h

Pre-Combustion Capture Scenario 5 CO_2 Compression (PFD Drawing: 64225A-DSC-00003)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Electric Power (MW)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des		
K-001	CO_2 Compressor Package	Multi-stage Integrally Geared Type Centrifugal Compressor	1/Train	Cr Ni alloy casing/impeller	171t/hr	28 to 136	Stage 1: 140/-10 Stage 2: 150 / -10 Stage 3: 150 / -10 Stage 4: 150 / -10 Stage 5: 100 / -89	Stage 1: 0.4 - 2.6 Stage 2: 2.2 - 7.2 Stage 3: 6.8 - 19.4 Stage 4: 19 - 53.1 Stage 5: 52.7 - 109	Stage 1: 10 Stage 2: 10 Stage 3: 25 Stage 4: 65 Stage 5: 125	18.79	Electric Motor Rating 20MW, 4 poles
V-101	1st stage suction knock out drum	Vertical	1/Train	SS304	H: 171t/hr	28	80/-10	0.4	10		
E-101	1st stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 171t/hr C 325t/hr	H: 127 - 30 C: 14 - 25	H:140/-10 C:80	H: 2.6 C: 4	H: 10; C: 3/FV		Duty: 4.3MW SW tubeside
V-102	2nd stage suction knock out drum	Vertical	1/Train	SS304	171t/hr	30	80/-10	2.3	10		
E-102	2nd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 171t/hr : C 320t/hr	H:126 - 30 ; C: 14-25	H:150/-10; C:80	H: 7.2 ; C: 4	H: 10; C: 3/FV		Duty: 4.3MW SW tubeside
V-103	3rd stage suction knock out drum	Vertical	1/Train	SS304	171t/hr	30	80/-10	6.9	10		
E-103	3rd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 171t/hr : C 347t/hr	H: 128.7 - 30 ; C: 14-25	H:150/-10; C:80	H:19.4 ; C: 4	H: 25; C: 3/FV		Duty: 4.7MW SW tubeside
V-104	4th stage suction knock out drum	Vertical	1/Train	SS304	171t/hr	30	80/-10	19.1	25		
E-104	4th stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 171t/hr : C 480t/hr	H:135.5 - 30; C: 14 - 25	H:150/-10; C:80	H: 53.1 ; C: 4	H: 76; C: 3/FV		Duty: 6.1MW Due to high pressure CO2 on tube side
V-105	5th stage suction knock out drum	Vertical	1/Train	SS304	171t/hr	30	80/-10	52.80	65		
TEG-101	TEG Dehydration Package		1/Train		171t/hr	30	150/-10	52.70	65		Less than 150 ppmv H2O
	CO_2 Analyser House		1								
E-105	5th stage discharge cooler		1/Train	Shell: SS304 Tube: SS304	H: 171t/hr : C: 727.8t/hr	H:101 - 30 ; C: 14-25	H:120/-89; C:80	H:109.3 ; C: 4	H: 125; C: 3/FV		Duty: 9.6MW Due to high pressure CO2 on tube side
P-101	Condensate return pump		1Train	SS304	0.124t/hr	31.30	80/-10	4.00	12		
	Permanent Universal Pig Launcher/Receiver		1	CS		30.00	80/-20	110.00			
	Flow metering and analyser package		1			30.00	80/-20	110.00			

APPENDIX B-5: EQUIPMENT LIST SCENARIO 6

Pre-Combustion Capture Scenario 6 (PFD Drawing: 64225A-DSC-00008)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Power (MWe)	IEA Sizing	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
F-001	Furnace Pre-Heater	Vertical Furnace	1/train	Cr-Mo steel furnace body with refractory lining at combustion zone	Gas Flowrate: 101t/h	2037	2500/-10	0.09	1.0/FV		L = 10m, W = 10m, H = 30m	Capacity: 72MWth
E-001	Furnace Pre-Heater 1	Coil tubes	1/train	2.25Cr-1.0Mo tubes	C: 218t/h H: 101t/h	C: 301/550 H: 2037/1066		C: 44.8 H: 0.09				Duty: 40.1MWth Pre-Reformer Feed Furnace Pre-Heater
E-002	Furnace Pre-Heater 2	Coil tubes	1/train	2.25Cr-1.0Mo tubes	C: 343t/h H: 101t/h	C: 347/540 H: 1066/534		C: 46 H: 0.08				Duty: 20MWth Reformer Process Air Furnace Pre-Heater
E-003	Furnace Pre-Heater 3	Coil tubes	1/train	1Cr-0.5Mo tubes	C: 74t/h H:101t/h	C: 231/341 H: 534/336		C: 45.4 H: 0.07				Duty: 6.8MWth Hydrogenator Feed Furnace Pre-Heater
E-004	Furnace Pre-Heater 4	Coil tubes	1/train	Carbon Steel tubes	C: 91t/h H: 101t/h	C: 19/200 H: 336/195		C: 0.1 H: 0.06				Duty: 4.7MWth Combustion Air Pre-Heater
E-024	Process Air Cooler 2	Shell&Tube	1/train	Shell: 1.0Cr-0.5Mo; Tubes: CS	C: 25t/h H: 343t/h	C: 65/153 H: 304/121	C: 375/-10 H: 450/-10	C: 4 H: 6	10.00		D = 1.267m, W = 7.531m, Total external heat transfer area = 60.87 m2 Heat transfer coefficient = 291.1 W/m2.C	Duty: 18MWth Process Steam Generator 1
PRS-002	Pressure Reducing Station 2	Pressure Regulating Valves	2/train	Carbon Steel	4t/h	In/Out: 50/19	100/-10	In/Out: 68.7/1	77.00			Natural Gas to Furnace Pre-Heater
PRS-003	Pressure Reducing Station 3	Pressure Regulating Valves	2/train	Carbon Steel	6t/h	In/Out: 71/70.4	125/-10	In/Out: 34.0/0.99	38.00			Hydrogen/Nitrogen to Furnace Pre-Heater
FA-001	Combustion Air Fan	Centrifugal Blower	1/train	Carbon Steel	91t/h	In/Out: 9/19.1	100/-10	In/Out: 0/0.1	1.0/FV	0.286		Part of F-001
K-001	Not Used											
K-002 a/b/c/d/e	Process Air Compressor	Centrifugal	1/train	1.0Cr-0.5Mo	343t/h	Stage 1 In/Out: 9/150.7 Stage 2 In/Out: 150.7/340 Stage 3 In/Out: 121/263 Stage 4 In/Out: 115/272.4 Stage 5 In/Out: 272.4/346.7	435/-10	Stage 1 In/Out: 0/1.8 Stage 2 In/Out: 1.8/6.4 Stage 3 In/Out: 5.8/13.9 Stage 4 In/Out: 13/32.6 Stage 5 In/Out:32.6/46	50.00	72.5	Stage 1: 13.6 MW Stage 2: 18.6MW Stage 3: 13.9MW Stage 4: 15.5MW Stage 5: 7.5MW	
E-023	Process Air Cooler 1	Shell&Tube	1/train	Shell: 1.0Cr-0.5Mo; Tubes: CS	C: 144t/h H: 343t/h	C: 265/300 H: 340/304	C: 375/-10 H: 450/-10	C: 49.4 H: 6.4	55.00		D = 1.699m, W = 17.19m, Total external heat transfer area = 1,940m2 Heat transfer coefficient = 263.6 W/m2.C	Duty: 3.53MWth Process Steam Superheater
PRS-004	Pressure Reducing Station 4	Pressure Regulating Valves	2/train	Carbon Steel	144t/h	In/Out: 300/297.8	375/-10	In/Out: 49.1/47.0	55.00			Process Steam PRS
E-025	Process Air Cooler 3	Shell&Tube	1/train	Vendor to Advise Shell: 1.0Cr-0.5Mo; Tubes: CS	C: 22t/h H: 343t/h	C: 65/144 H: 263/115	425/-10	C: 4 H: 14	16.00		D = 4.482m, W = 17.1m, Total external heat transfer area = 1,310 m2 Heat transfer coefficient = 281.8 W/m2.C	Duty: 13 MWth LP Steam Generator
E-026	Process Air Cooler 4	Shell&Tube	1/train	Shell: 1.0Cr-0.5Mo; Tubes: CS	C: 93.5t/h H: 343t/h	C: 14.5/25 H: 129/115	C: 35/-10 H: 150/-10	C: 4 H: 13.3	15.00		D = 1.22m, W = 6.526m, Total external heat transfer area = 28.04m2 Heat transfer coefficient = 320.9W/m2.C	Duty: 1.3MWth Cooling Water
E-027	Process NG Letdown Station Heater	Shell&Tube	1/train	Carbon Steel	C: 73.6t/h H: 56t/h	C: 9/25 H: 83/71	C: 50/-10 H: 150/-10	C: 69 H: 2.6	76.00		D = 0.3831m, W = 1.869m, Total external heat transfer area = 20.92 m2 Heat transfer coefficient = 559.9 W/m2.C	Duty: 0.9MWth LP Condensate
E-028	Furnace NG Letdown Station Heater	Shell&Tube	1/train	Carbon Steel	C: 4t/h H: 56t/h	C: 9/50 H: 71/69	C: 100/-10 H: 150/-10	C: 69 H: 2.1	76.00		D = 0.3302m, W = 1.716m Total external heat transfer area = 8.773m2 Heat transfer coefficient = 307.2 W/m2.C	Duty: 0.1MWth LP Condensate
PRS-001	Pressure Reducing Station 1	Pressure Regulating Valves	2/train	Carbon Steel	74t/h	In/Out: 25/15	50/-10	In/Out: 68.7/47	76.00			Natural Gas to Process
E-007	Not Used											

Pre-Combustion Capture Scenario 6 (PFD Drawing: 64225A-DSC-00008)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Power (MWe)	IEA Sizing	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
E-008	Hydrogenator Feed LP Steam Pre-Heater	Shell&Tube	1/train	CS Shell (Gas) SS Tube (Steam)	C: 74t/h H: 3t/h	C: 15/52 H: 164/120	C: 85/-10 H: 205/-10	C: 46 H: 4	51.00		D =0.3733m, W = 2.719m, Total external heat transfer area = 30.96m2 Heat transfer coefficient = 489.4W/m2.C	Duty: 2MWth
E-009	Hydrogenator Feed IP Steam Pre-Heater	Shell&Tube	1/train	CS Shell (Gas) SS Tube (Steam)	C: 74t/h H: 20t/h	C: 52/231 H: 265/260	C: 300/-10 H: 330/-10	C: 46 H: 49	55.00		D =0.7181m, W = 4.328m Total external heat transfer area = 223 m2 Heat transfer coefficient = 424.5W/m2.C	Duty: 9.6MWth
K-003	H2/N2 Gas Compressor	Centrifugal	1/train	Carbon Steel	0.5t/h	In/Out: 71/104	170/-10	In/Out: 36.1/46	55.00	0.01		Single-Stage Compression
C-001	Hydrogenator	Reactor	1/train	External: CS Internals: SS	74t/h	341	430/-10	In/Out: 45.3/44.8	50.00			
C-002A/B	Desulphuriser	Reactor	2/train	External: CS Internals: SS	37t/h	341	430/-10	44.8	50.00			
E-010	Not Used											
R-001	Pre-Reformer	Reactor	1/train	External: SS304 Internals: SS	218t/h	In/Out: 550/547	690/-10	In/Out: 44.5/42.6	50.00			
R-002	Autothermal Reformer	Reactor	1/train	External: DIN17135 CS Internal: Refractory Brickwork at combustion zone	561t/h	Combustion Zone: 1335	1700/-10	In/Out: 43/41	47.50		Dia: 6m Pack Height: 10m Total Height: 65m	
E-011	Not Used											
E-012	Syngas Cooler 1	Convective Shell&Tube	1/train	Shell: CS Tube: Alloy Steel	C: 339t/h H: 561t/h	C: 259/265 H: 912/348	C: 330/-10 H: 1200/-10	C: 50 H: 41	55.00		D = 2.588, W =20.16m, Total external heat transfer area = 1277.9 m2 Heat transfer coefficient = 468.1 W/m2.C	Duty: 163.3MWth IP Steam Generator
D-001	IP Steam Drum	Horizontal	1/train	Carbon Steel	339t/h 611Am3/h	Sat Temp: 264.7	340/-10	51	56.00		D = 4.676m, W = 16.61m Total external heat transfer area = 1,070 m2 Heat transfer coefficient = 468.3 W/m2.C	Part of IP Steam Generator
R-003	High Temperature Shift Reactor	Reactor	1/train	1.0Cr-0.5Mo	561t/h	In/Out: 348/419	525/-10	In/Out: 40.3/39.6	45.00		ID: 8.4m T/T: 3.1m Total Height:7.75m	
E-013	Syngas Cooler 2	Shell&Tube	1/train	1.0Cr-0.5Mo	C: 319t/h H: 561t/h	C: 150/263 H: 419/231	C: 330/-10 H: 525/-10	C: 50.5 H: 39.6	56.00		D =0.8106m, W = 19.47m Total external heat transfer area = 1,340 m2 Heat transfer coefficient = 283.5 W/m2.C	Duty: 52.3MWth IP Boiler Feedwater Heater
R-004	Low Temperature Shift Reactor	Reactor	1/train	1.25Cr-0.5Mo	561t/h	In/Out: 231/253	315/-10	In/Out: 39.4/38.1	45.00		ID: 11.2m Packing Height: 2.7m Total Height: 6m	
E-014	LT Shift Reactor Product Cooler 1	Convective Shell&Tube	1/train	Shell: CS Tube: CS	C: 26t/h H: 561t/h	C: 154/164 H: 253/195	315/-10	C: 4.7 H: 38.1	42.00		D =1.443m, W = 5.017m Total external heat transfer area = 4.568 m2 Heat transfer coefficient = 170.4 W/m2.C	Duty: 16.1MWth LP Steam Generator

Pre-Combustion Capture Scenario 6 (PFD Drawing: 64225A-DSC-00008)

PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Power (MWe)	IEA Sizing	Comments
						Normal Op	Mech Des	Normal Op	Mech Des			
D-002	LP Steam Drum	Horizontal	1/train	Carbon Steel	26t/h 38.9Am3/h	Sat Temp: 155	195/-10	4.4	5.00		D =3.499m, W = 12.73m Total external heat transfer area = 526 m2 Heat transfer coefficient = 489.6 W/m2.C	Part of LP Steam Generator
E-015	LT Shift Reactor Product Cooler 2	Shell&Tube	1/train	Carbon Steel	C: 26t/h H: 561t/h	C: 110/154 H: 195/189	250/-10	C: 5.2 H: 37.8	42.00		D =1.121m, W = 6.049m Total external heat transfer area = 51.39 m2 Heat transfer coefficient = 413.1 W/m2.C	Duty: 1.6MWth LP Boiler Feedwater Heater
E-016	LT Shift Reactor Product Cooler 3	Shell&Tube	1/train	Carbon Steel	C: 319t/h H: 561t/h	C: 19.6/150 H: 189/122	250/-10	C: 51.0 H: 37.5	57.00		D =1.439m, W = 14.6m Total external heat transfer area = 1,440 m2 Heat transfer coefficient = 498.3 W/m2.C	Duty: 56MWth IP Boiler Feedwater Heater
E-017	LT Shift Reactor Product Cooler 4	Shell&Tube	1/train	Carbon Steel	C: 5060t/h H: 561t/h	C: 14.4/25 H: 122/20	150/-10	C: 4.0 H: 37.2	41.00		D =2.749m, W = 19.95m Total external heat transfer area = 6,070 m2 Heat transfer coefficient = 319.8 W/m2.C	Duty: 46MWth Cooling Water
D-003	Knock-Out Drum	Vertical	1/train	Carbon Steel	Inlet Flow: 564t/h	20	50/-10	36.9	41.00		ID = 7m, H = 5.25m	Knocked out: Condensate 88.1t/h, 95.1Am3/h
C-003	CO_2 Absorber	Vertical	1/train	Column: CS Internals: CS	Liquid Feed: 5400t/h Gas Feed: 509t/h	Top: -5.2 Bottom: 2.0	10/-10	Top: 36.31 Bottom: 36.81	41.00		ID: 7.3m	Sulzer Melapak 250Y Structured Packing
	Absorber packing	Structured Mellapak 250Y	1/train	SS316L							No. Stages: 20	Sulzer Melapak 250Y Structured Packing
E-029	H2/N2 Fuel Heater	Shell&Tube	1/train	Carbon Steel	C: 6.5t/h H: 0.5t/h	C: -4/71 H: 144/144	C: 125/-10 H: 205/-10	C: 36.3 H: 2.9	40.00		D = 0.3587m, W = 1.675m, Total external heat transfer area = 3.461m2 Heat transfer coefficient = 874.9 W/m2.C	Duty: 0.28MWth LP Steam
D-004	Flash Drum 1	Vertical	1/train	Carbon Steel	Inlet Liquid: 5606t/h, 5223Am3/h Gas Out (Top): 35.8t/h, 3097Am3/h Liquid Out (Bottom): 5571t/h, 5177Am3/h	In/Out: 2/0.1	10/-10	In/Out: 36.8/8.0	40.00		ID = 11m, H = 8.25m	
D-005	Flash Drum 2	Vertical	1/train	Carbon Steel	Inlet Liquid: 5571t/h, 5177Am3/h Gas Out (Top): 117t/h, 40533Am3/h Liquid Out (Bottom): 5454t/h, 5036Am3/h	In/Out: 0.1 / -4.6	10/-10	In/Out: 8.0/0.5	9.00		ID = 10.5m, H = 7.9m	
E-018	Lean Solvent Cooler	Shell&Tube	3/train	Carbon Steel Frame / Hastelloy C-276 Plates	C: 5454t/h H: 5400t/h	C: -4.6/2.5 H: 9.2/0.8	C: 10/-10 H: 10/-10	C: 0.5 H: 37.2	41.00		D = 5.242m, W = 64.19m, Total external heat transfer area = 84,900 m2 Heat transfer coefficient = 63.16 W/m2.C	Duty: 24MWth
E-019	Semi-Lean Solvent Heater	Shell&Tube	1/train	Carbon Steel	C: 5454t/h H: 33t/h	C: 2.5/8.5 H: 143/140	C: 10/-10 H: 205/-10	C: -0.01 H: 2.9	5.00/FV		D =1.167m, W = 4.421m Total external heat transfer area = 244m2 Heat transfer coefficient = 583.6 W/m2.C	Duty: 19MWth LP Steam
E-020	Lean Solvent Chiller	Package Absorption Chiller	1/train	Vendor package	5400t/h	In/Out: 0.8/-10	10/-12.5	In/Out: 36.7/36.2	41.00	VTA	L = 20m, W = 14.9m	Duty: 30MWth Package Chiller

Pre-Combustion Capture Scenario 6 (PFD Drawing: 64225A-DSC-00008)

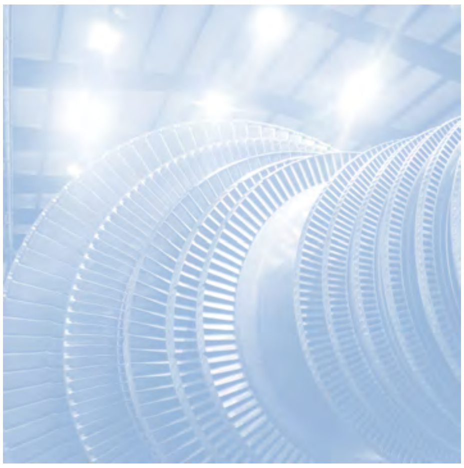
PFD Ref	Description	Type	Qty	Materials	Flowrate	Temperature (°C) Normal Op	Temperature (°C) Mech Des	Pressure (Barg) Normal Op	Pressure (Barg) Mech Des	Power (MWe)	IEA Sizing	Comments
D-006	Flash Drum 3	Vertical	1/train	Carbon Steel	Inlet Liquid: 5454t/h, 43245Am3/h Gas Out (Top): 53.7t/h, 47712Am3/h Liquid Out (Bottom): 5400t/h, 5052Am3/h	In/Out: 8.5/8.3	10/-10	In/Out: -0.3/-0.4	1.00/FV		ID = 10.5m, H = 7.9m	
P-001	Lean Solvent Pump	Multistage Centrifugal Fixed RPM	2/train	Carbon Steel	5400t/h	In/Out: 8.3/9.2	7.5/-10	In/Out: -0.4/37.2	40.00/FV	6.1	Base Plate Size: L = 5.575m, W = 2.034m	Pump suction under vacuum
K-004	CO_2 Absorber Gas Recycle Compressor	Centrifugal	1/train	Carbon Steel	36t/h	In/Out: 0.1/109.5	135/-10	In/Out: 8/37.8	42.00	1.9		Two-Stage Compression
E-021	CO2 Absorber Gas Recycle Compressor Inter-Cooler	Shell&Tube	1/train	Carbon Steel	C: 77t/h H: 36t/h	C: 14.4/25 H: 88/30	C: 35/-10 H: 110/-10	C: 4 H: 19	21.00		D = 0.6601m, W = 4.059m, Total external heat transfer area = 55.56 m2 Heat transfer coefficient = 370.4 W/m2.C	Duty: 0.7MWth
E-022	CO_2 Absorber Gas Recycle Compressor Cooler	Shell&Tube	1/train	Carbon Steel	C: 124t/h H: 36t/h	C: 14.4/25 H: 109/20	C: 35/-10 H: 135/-10	C: 4 H: 37.8	42.00		D = 0.5814m, W = 5.386m Total external heat transfer area =77.19 m2 Heat transfer coefficient = 410.3 W/m2.C	Duty: 1.1MWth Cooling Water
K-005	Flash Drum 3 CO_2 Booster Compressor	Centrifugal	1/train	Casing: CS Impeller: SS	53.7t/h	In/Out: 8.3/97.5	120/-10	In/Out: -0.4/0.49	1.0/FV	1.2	L = 6.25m x W = 3m x H = 2.75m	Single-Stage Compression
K-006	H2/N2 Fuel Compressor to Storage	Centrifugal	1/train	Casing: CS Impeller: SS	296.1t/h	In/Out: -4.2/56.5	80 / -10	In/Out: 36.3/62	70	10.2		
PL-001	H2/N2 Pipeline to Storage	Pipe	1/train	Carbon Steel	296.1t/h	In/Out: 57/6		In/Out: 62/36			OD: 36 inch, IDnominal: 900mm, Length: 50km	
E-007	Boiler Feedwater Condensate Cooler	Shell&Tube	1/train	Carbon Steel	C: 1008t/h H: 194t/h	C: 14.4/25 H: 74.6/20		C: 4 H: 1.8			D = 0.7378m, W = 17.53m Total external heat transfer area =449 m2 Heat transfer coefficient = 1314.5 W/m2.C	Duty: 14.2MWth Cooling Water
ST-001	Steam Turbine Generator	Condensing ST	1/plant		260.8t/h	In/Out: 265/45.8		In/Out: 49/-0.913			Electric Generator: L = 8.4m x W = 4.5m Steam Turbine: L = 8m x W = 6m Lub Oil System: L = 5m x W= 3m	Gross Power Output: 49.85MWe IP Waste Heat from Reformer Process
	CO_2 Vent	Stack	1/plant	Carbon Steel	170.2t/hr	29	80/-10	0.4	10			
	Flare Stack	Guy-supported	1/plant	Carbon Steel		71	125/-10	36.3	40.00		24" diameter, 70m H	
	Selexol Storage Tank	Storage tank	1/plant	Carbon Steel		30.00	80 / -10	0.02	0.056 / - 0.006		2600m^3	Sized for liquid inventory of CO_2 Absorber and Flash Drums D-004, D-005, and D-006
CT-001	Cooling Tower	Mechanical	1/plant	Concrete	Cooling water: 15195t/h	In/Out: 14.4/25	35/-10	4.00	21.00	3.15	14 Cells, W: 32.36m x L: 113.26m	Include abs chiller CW: 6629t/h

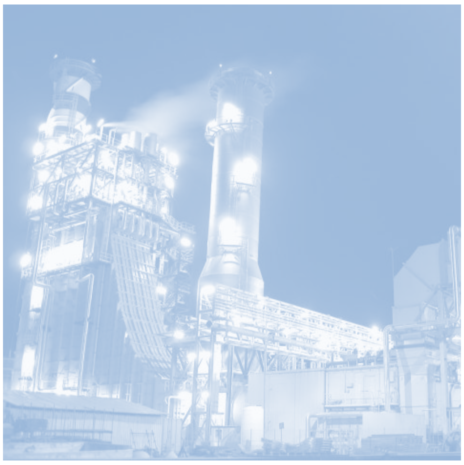
Pre-Combustion Capture Scenario 6 CO_2 Compression (PFD Drawing: 64225A-DSC-00009)

ID No.	Description	Type	Qty	Materials	Flowrate	Temperature (°C)		Pressure (Barg)		Electric Power (MW)	Comments
						Normal Op	Mech Des	Normal Op	Mech Des		
K-001	CO_2 Compressor Package	Multi-stage Integrally Geared Type Centrifugal Compressor	1/Train	Cr Ni alloy casing/impeller	170.4t/hr	28 to 136	Stage 1: 140/-10 Stage 2: 150 / -10 Stage 3: 150 / -10 Stage 4: 150 / -10 Stage 5: 100 / -89	Stage 1: 0.4 - 2.6 Stage 2: 2.2 - 7.2 Stage 3: 6.8 - 19.4 Stage 4: 19 - 53.1 Stage 5: 52.7 - 109	Stage 1: 10 Stage 2: 10 Stage 3: 25 Stage 4: 65 Stage 5: 125	18.69	Electric Motor Rating 20MW, 4 poles
V-101	1st stage suction knock out drum	Vertical	1/Train	SS304	H: 170.4t/hr	28	80/-10	0.4	10		
E-101	1st stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 170.4t/hr C: 330.3t/hr	H:127 - 30 ; C: 14 - 25	H:140/-10; C:80	H: 2.6 ; C: 4	H: 10; C: 3/FV		Duty: 4.2MW SW tubeside
V-102	2nd stage suction knock out drum	Vertical	1/Train	SS304	170.4t/hr	30	80/-10	2.3	10		
E-102	2nd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 170.4t/hr C: 339t/hr	H:126 - 30 ; C: 14 - 25	H:150/-10; C:80	H: 7.2 ; C: 4	H: 10; C: 3/FV		Duty: 4.3MW SW tubeside
V-103	3rd stage suction knock out drum	Vertical	1/Train	SS304	170.4t/hr	30	80/-10	6.9	10		
E-103	3rd stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 170.4t/hr C: 355t/hr	H: 129 - 30 ; C: 14-25	H:150/-10; C:80	H:19.4 ; C: 4	H: 25; C: 3/FV		Duty: 4.7MW SW tubeside
V-104	4th stage suction knock out drum	Vertical	1/Train	SS304	170.4t/hr	30	80/-10	19.1	25		
E-104	4th stage discharge cooler	Shell and tube	1/Train	Shell: SS304 Tube: SS304	H: 170.3t/hr C: 466t/hr	H:135.5 - 30; C: 14 - 25	H:150/-10; C:80	H: 53.1 ; C: 4	H: 76; C: 3/FV		Duty: 6.1MW Due to high pressure CO2 on tube side
V-105	5th stage suction knock out drum	Vertical	1/Train	SS304	170.3t/hr	30	80/-10	52.80	65		
TEG-101	TEG Dehydration Package		1/Train		170.3t/hr	30	150/-10	52.70	65		Less than 150 ppmv H2O
	CO_2 Analyser House		1								
E-105	5th stage discharge cooler		1/Train	Shell: SS304 Tube: SS304	H: 170.2t/hr : C: 709t/hr	H:100 - 30 ; C: 14 - 25	H:120/-89; C:80	H:109.3 ; C: 4	H: 125; C: 3/FV		Duty: 9.5MW Due to high pressure CO2 on tube side
P-101	Condensate return pump		1Train	SS304	0.154t/hr	31.70	80/-10	4.00	12		
	Permanent Universal Pig Launcher/Receiver		1	CS		30.00	80/-20	110.00			
	Flow metering and analyser package		1			30.00	80/-20	110.00			

APPENDIX

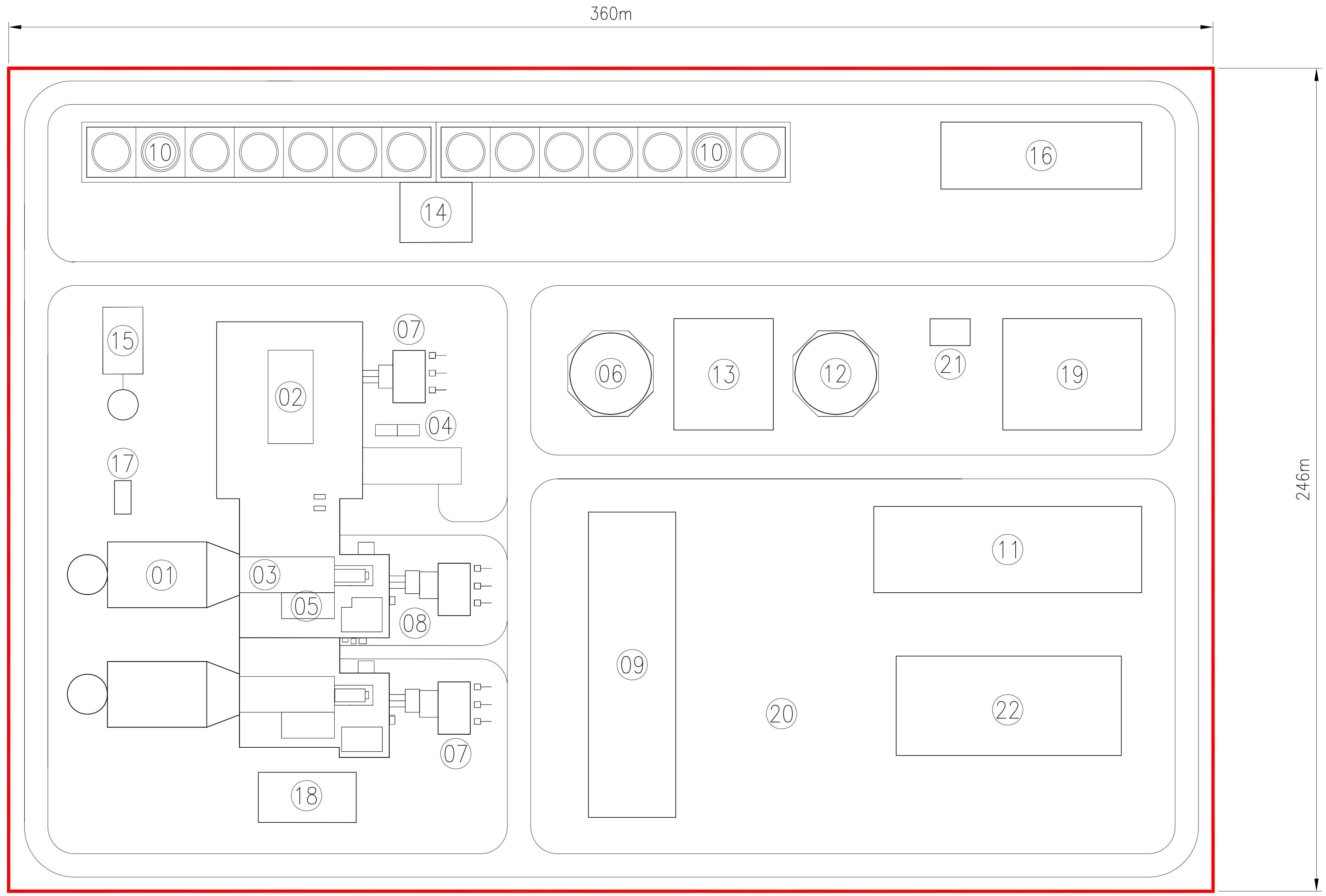
C





LAYOUT DRAWINGS

APPENDIX C-1: LAYOUT DRAWING SCENARIO 1



LEGEND

01	HEAT RECOVERY STEAM GENERATOR		09	GI SWITCHYARD		17	EMERGENCY DIESEL GENERATORS
02	STEAM TURBINE AREA		10	COOLING TOWERS		18	CONTROL BUILDING
03	GAS TURBINE AREA		11	WAREHOUSE/MAINT./ADMIN		19	RAW-WATER PRE-TREATMENT
04	CO2 LOW PRESSURE STATION		12	RAW WATER/ FIREWATER STORAGE TANK		20	POSSIBLE LAYDOWN/OPEN STORAGE AREA
05	GAS TURBINE INLET FILTER		13	WATER TREATMENT BUILDING		21	FIRE FIGHTING PUMPHOUSE
06	DEMINERALIZED WATER STORAGE TANK		14	CW PUMPHOUSE		22	CAR PARKING
07	MAIN TRANSFORMER		15	AUXILIARY BOILER			
08	AUXILIARY TRANSFORMER		16	GAS CONDITIONING FACILITY			

0 25m 50m 75m 100m

BAR SCALE 1:1500

Project Number: | Drawing Number: | Revision:

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\Z. Drawings\1. Current\CO2 Capture\00010.dwg

Login: Stenhoff, Mark
Plot Date: 07/03/2012 12:09:19

Rev	Date	Description	By	Chk	App	Notes:

PARSONS BRINCKERHOFF
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Fax: 44-(0)191-226-2104

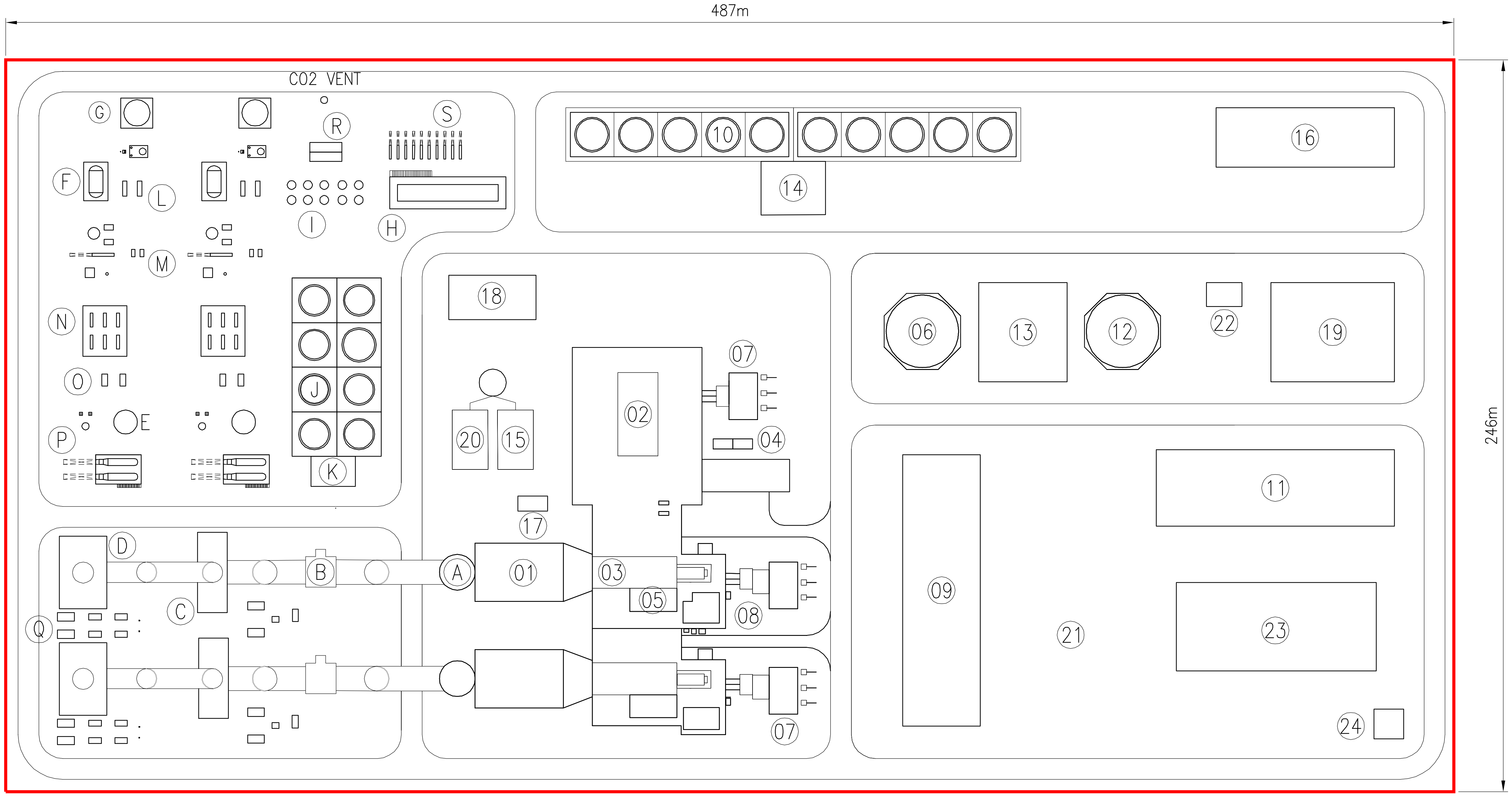
Client:
IEA ENVIRONMENTAL PROJECTS LTD

Project:
CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title:
CCGT REFERANCE PLANT (NO CARBON CAPTURE)

Drawn:	DD		Checked:	RC	
Designed:	DD		Approved:	RC	
Date:	28/06/2011	Scale: 1/1500	A3	Sheet:	
Project Number:		Drawing Number:			Revision:
64225A		-DSC-00010			

APPENDIX C-2: LAYOUT DRAWING SCENARIO 3



LEGEND

- (01) HEAT RECOVERY STEAM GENERATOR
- (02) STEAM TURBINE AREA
- (03) GAS TURBINE AREA
- (04) CO2 LOW PRESSURE STATION
- (05) GAS TURBINE INLET FILTER
- (06) DEMINERALIZED WATER STORAGE TANK
- (07) MAIN TRANSFORMER
- (08) AUXILIARY TRANSFORMER
- (09) GI SWITCHYARD
- (10) COOLING TOWERS
- (11) WAREHOUSE/MAINT./ADMIN
- (12) RAW WATER/ FIREWATER STORAGE TANK
- (13) WATER TREATMENT BUILDING
- (14) CW PUMPHOUSE
- (15) AUXILIARY BOILER
- (16) GAS CONDITIONING FACILITY
- (17) EMERGENCY DIESEL GENERATORS
- (18) CONTROL BUILDING
- (19) RAW WATER PRE-TREATMENT
- (20) AUXILIARY BOILER FOR CCS
- (21) POSSIBLE LAYDOWN/OPEN STORAGE AREA
- (22) FIRE FIGHTING PUMPHOUSE
- (23) CAR PARK
- (24) GATE HOUSE
- (A) STACK
- (B) BLOWER
- (C) DIRECT CONTACT COOLER
- (D) ABSORBER
- (E) STRIPPER
- (F) RECLAIMER
- (G) SOLVENT STORAGE TANK
- (H) CO2 COMPRESSOR HOUSE
- (I) KNOCKOUT DRUMS
- (J) COOLING TOWERS
- (K) CW PUMP HOUSE
- (L) LEAN SOLVENT COOLERS
- (M) SOLVENT STORAGE PUMPS
- (N) SOLVENT CROSS EXCHANGERS
- (O) LEAN SOLVENT PUMPS
- (P) REBOILERS
- (Q) DCC PUMPS & COOLERS & ABSORBER PUMPS
- (R) TEG DEHYDRATION PACKAGE
- (S) COMPRESSOR INTER-STAGE COOLERS

0 25m 50m 75m 100m

BAR SCALE 1:1500

Rev	Date	Description	By	Chk	App	Notes:

PARSONS BRINCKERHOFF

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Newcastle upon Tyne NE4 7YQ
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Client: IEA ENVIRONMENTAL PROJECTS LTD

Project: CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title: CCGT WITH POST COMBUSTION CO2 CAPTURE AND COMPRESSION PLANT

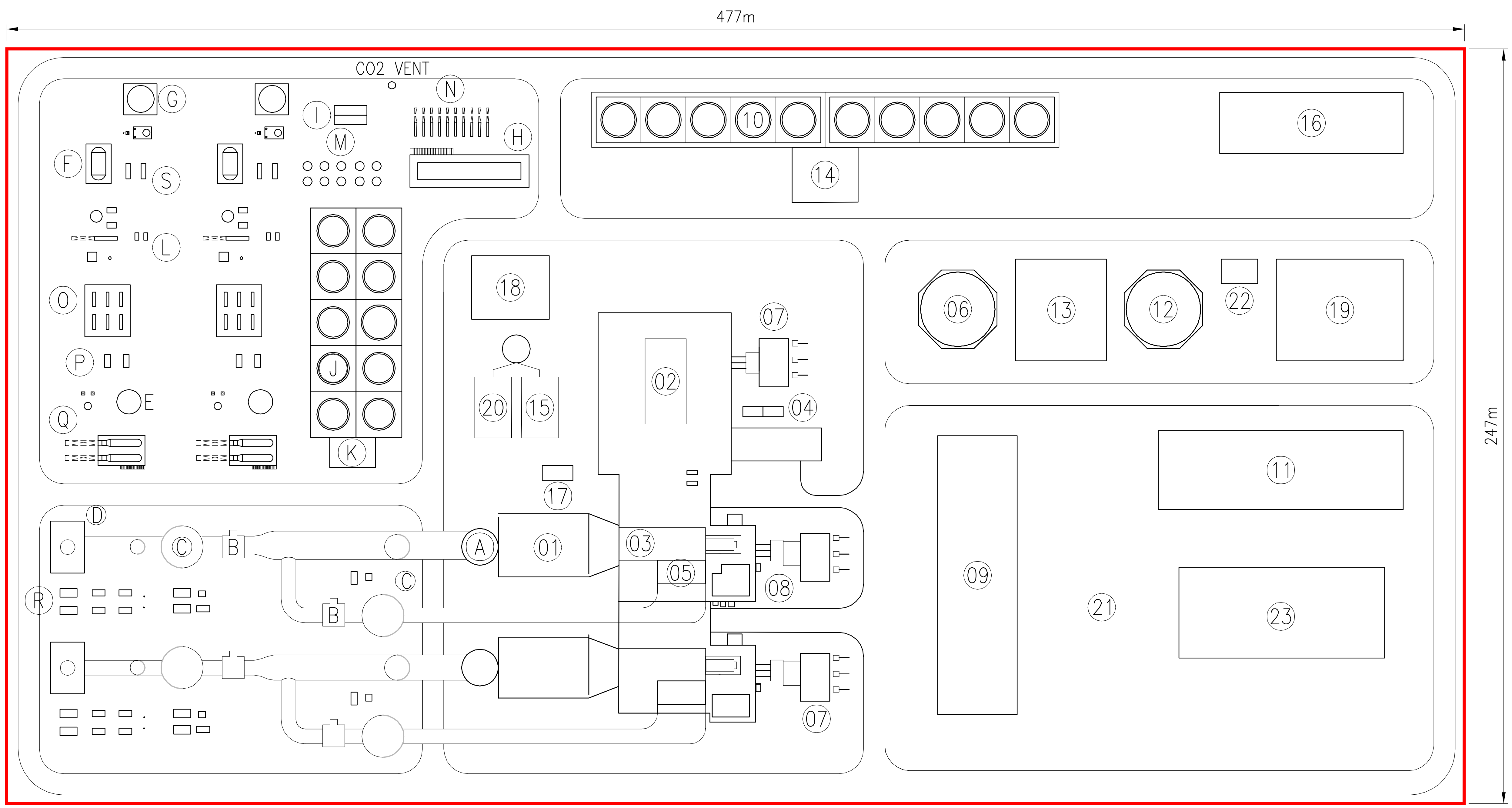
Drawn: DD		Checked: NS	
Designed: DD		Approved: NS	
Date: 05/08/2011	Scale: 1/1500	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00011		Revision: 1

Project Number: | Drawing Number: | Revision:

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\2. Drawings\1. Current\CO2 Capture\00011.dwg

Login: Brindley, Barry
Plot Date: 04/11/2011 16:25:10

APPENDIX C-3: LAYOUT DRAWING SCENARIO 4



LEGEND

01	HEAT RECOVERY STEAM GENERATOR	A	STACK
02	STEAM TURBINE AREA	B	BLOWER
03	GAS TURBINE AREA	C	DIRECT CONTACT COOLER
04	CO2 LOW PRESSURE STATION	D	ABSORBER
05	GAS TURBINE INLET FILTER	E	STRIPPER
06	DEMINERALIZED WATER STORAGE TANK	F	RECLAIMER
07	MAIN TRANSFORMER	G	SOLVENT STORAGE TANK
08	AUXILIARY TRANSFORMER	H	CO2 COMPRESSOR HOUSE
09	GI SWITCHYARD	I	TEG DEHYDRATION PACKAGE
10	COOLING TOWERS	J	COOLING TOWERS
11	WAREHOUSE/MAINT./ADMIN	K	CW PUMP HOUSE
12	RAW WATER/ FIREWATER STORAGE TANK	L	SOLVENT STORAGE PUMPS
13	WATER TREATMENT BUILDING	M	KNOCKOUT DRUMS
14	CW PUMPHOUSE	N	COMPRESSOR INTER-STAGE COOLERS
15	AUXILIARY BOILER	O	SOLVENT CROSS EXCHANGERS
16	GAS CONDITIONING FACILITY	P	LEAN SOLVENT PUMPS
17	EMERGENCY DIESEL GENERATORS	Q	REBOILERS
18	CONTROL BUILDING	R	DCC PUMPS & COOLERS & ABSORBER PUMPS
19	RAW WATER PRE-TREATMENT	S	LEAN SOLVENT COOLERS
20	AUXILIARY BOILER FOR CCS		
21	POSSIBLE LAYDOWN/OPEN STORAGE AREA		
22	FIRE FIGHTING PUMPHOUSE		
23	CAR PARK		

0 20m 40m 60m 80m

BAR SCALE 1:1500

Rev	Date	Description	By	Chk	App	Notes:

PARSONS BRINCKERHOFF
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Amber Court
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Newcastle upon Tyne NE4 7YQ
Tel: 44-(0)191-226-2000
Fax: 44-(0)191-226-2104

Client:
IEA ENVIRONMENTAL PROJECTS LTD

Project:
CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title:
CCGT WITH RECIRCULATION AND POST COMBUSTION CO2 CAPTURE AND COMPRESSION PLANT

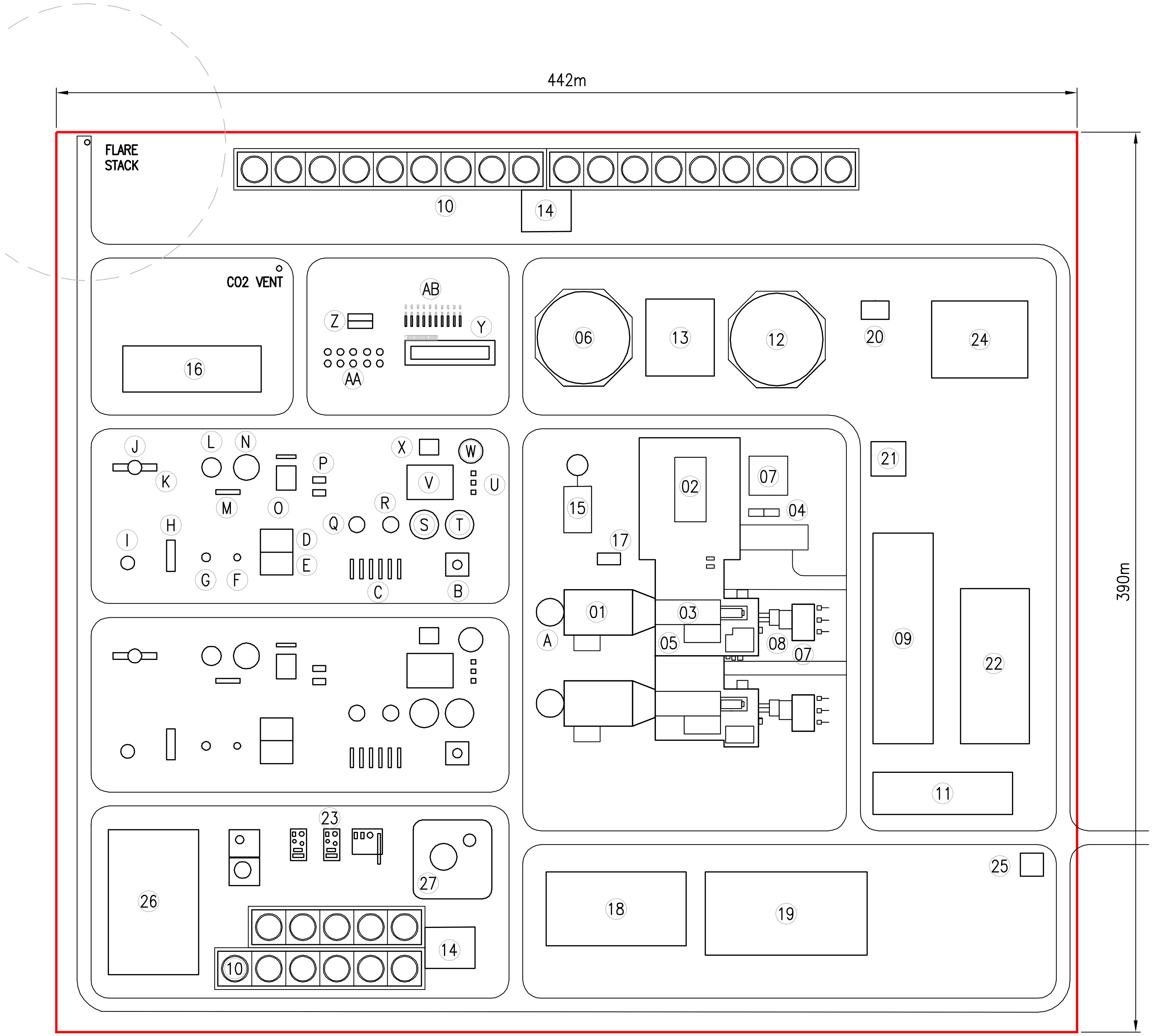
Drawn: DD		Checked: RC	
Designed: DD		Approved: RC	
Date: 07/07/2011	Scale: 1/1500	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00012		Revision:

Revision | Drawing Number | Project Number

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\Z. Drawings\1. Current\CO2 Capture\00012.dwg

Login: Brindley, Barry
Plot Date: 17/11/2011 10:49:29

APPENDIX C-4: LAYOUT DRAWING SCENARIO 5



LEGEND

01	HEAT RECOVERY STEAM GENERATOR	A	STACK
02	STEAM TURBINE AREA	B	FURNACE PRE-HEATER
03	GAS TURBINE AREA	C	NATURAL GAS/PROCESS AIR/PROCESS STEAM PRE HEATERS
04	CO2 LOW PRESSURE STATION	D	H_2/N_2 COMPRESSOR
05	GAS TURBINE INLET FILTER	E	PROCESS AIR BOOSTER COMPRESSOR
06	DEMINERALISED WATER STORAGE TANK	F	HYDROGENATOR
07	MAIN TRANSFORMER	G	DESULPHURISER
08	AUXILIARY TRANSFORMER	H	WASTE HEAT RECOVERY (LP STEAM)
09	GI SWITCHYARD	I	PRE-REFORMER
10	COOLING TOWERS	J	AUTOTHERMAL REFORMER
11	ADMINISTRATION	K	WASTE HEAT RECOVERY (IP STEAM)
12	RAW WATER/ FIREWATER STORAGE TANK	L	HT SHIFT REACTOR
13	WATER TREATMENT BUILDING	M	SYNGAS COOLER 2
14	CW PUMPHOUSE	N	LT SHIFT REACTOR
15	AUXILIARY BOILER	O	WASTE HEAT RECOVERY (LP STEAM)
16	GAS CONDITIONING FACILITY	P	SYNGAS COOLERS
17	EMERGENCY DIESEL GENERATORS	Q	KNOCK OUT DRUM
18	CONTROL BUILDING	R	CO_2 ABSORBER
19	WORKSHOP/STORAGE	S	FLASH DRUM 1
20	FIRE FIGHTING PUMP HOUSE	T	FLASH DRUM 2
21	FIRE STATION	U	SOLVENT H/EX
22	CAR PARK/LAYDOWN	V	ABSORPTION CHILLER
23	CONDENSATE POLISHING	W	FLASH DRUM 3
24	RAW-WATER PRE-TREATMENT	X	CO2 COMPRESSOR (BOOSTER)
25	GATE HOUSE	Y	CO2 COMPRESSOR HOUSE
26	EFFLUENT TREATMENT PLANT	Z	TEG DEHYDRATION PACKAGE
27	SELEXOL STORAGE AREA	AA	KNOCKOUT DRUMS
		AB	INTER-STAGE DISCHARGE COOLER

0 20m 40m 60m 80m 100m

BAR SCALE 1:2000

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\Z. Drawings\1. Current\CO2 Capture\00013.dwg

Login: Logan Coulsey, Michael
Plot Date: 21/12/2011 13:49:23

Rev	Date	Description	By	Chk	App	Notes:

PARSONS BRINCKERHOFF
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William Armstrong Drive
Newcastle upon Tyne NE4 7YQ
Tel: 44-(0)191-226-2000
Fax: 44-(0)191-226-2104

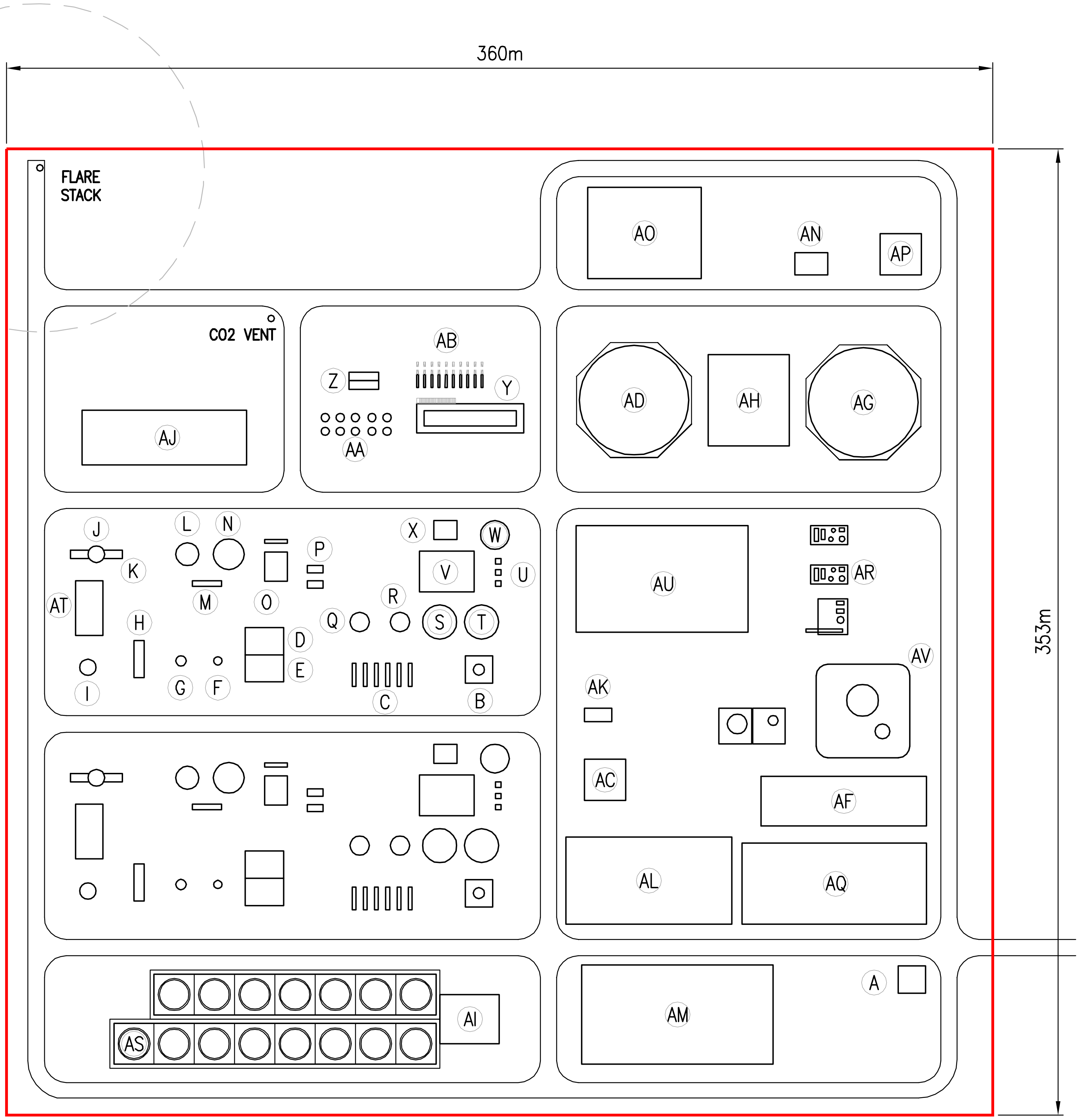
Client: IEA ENVIRONMENTAL PROJECTS LTD

Project: CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

Title: COMBINED CYCLE POWER PLANT WITH REFORMING OR PARTIAL OXIDATION PLANT AND PRE-COMBUSTION CAPTURE

Drawn: MLC		Checked: IA	
Designed: MLC		Approved: GM	
Date: 03/08/2011	Scale: 1/2000	A3	Sheet:
Project Number: 64225A	Drawing Number: -DSC-00013		Revision:

APPENDIX C-5: LAYOUT DRAWING SCENARIO 6



LEGEND

AA	KNOCKOUT DRUMS
AB	INTER–STAGE DISCHARGE COOLER
AC	STEAM TURBINE AREA
AD	DEMINERALIZED WATER STORAGE TANK
AE	AUXILIARY TRANSFORMER
AF	ADMINISTRATION
AG	RAW WATER/ FIREWATER STORAGE TANK
AH	WATER TREATMENT BUILDING
AI	CW PUMPHOUSE
AJ	GAS CONDITIONING FACILITY
AK	EMERGENCY DIESEL GENERATORS
AL	CONTROL BUILDING
AM	WORKSHOP/STORAGE
AN	FIRE FIGHTING PUMP HOUSE
AO	RAW–WATER PRE–TREATMENT
AP	FIRE STATION
AQ	CAR PARK/LAYDOWN
AR	CONDENSATE POLISHING
AS	COOLING TOWERS
AT	PROCESS AIR COMPRESSOR
AU	EFFLUENT TREATMENT PLANT
AV	SELEXOL STORAGE AREA
A	GATE HOUSE
B	FURNACE PRE–HEATER
C	NATURAL GAS/PROCESS AIR/PROCESS STEAM PRE HEATERS
D	H_2/N_2 COMPRESSOR
E	PROCESS AIR BOOSTER COMPRESSOR
F	HYDROGENATOR
G	DESULPHURISER
H	WASTE HEAT RECOVERY (LP STEAM)
I	PRE–REFORMER
J	AUTOTHERMAL REFORMER
K	WASTE HEAT RECOVERY (IP STEAM)
L	HT SHIFT REACTOR
M	SYNGAS COOLER 2
N	LT SHIFT REACTOR
O	WASTE HEAT RECOVERY (LP STEAM)
P	SYNGAS COOLERS
Q	KNOCK OUT DRUM
R	CO_2 ABSORBER
S	FLASH DRUM 1
T	FLASH DRUM 2
U	SOLVENT H/EX
V	ABSORPTION CHILLER
W	FLASH DRUM 3
X	CO2 COMPRESSOR (BOOSTER)
Y	CO2 COMPRESSOR HOUSE
Z	TEG DEHYDRATION PACKAGE

0 20m 40m 60m 80m 100m

BAR SCALE 1:2000

Revision | Drawing Number | Project Number

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\Z. Drawings\1. Current\CO2 Capture\00014.dwg

Login: Logan Coulsey, Michael
Plot Date: 21/12/2011 13:46:10

Rev	Date	Description	By	Chk	App	Notes:

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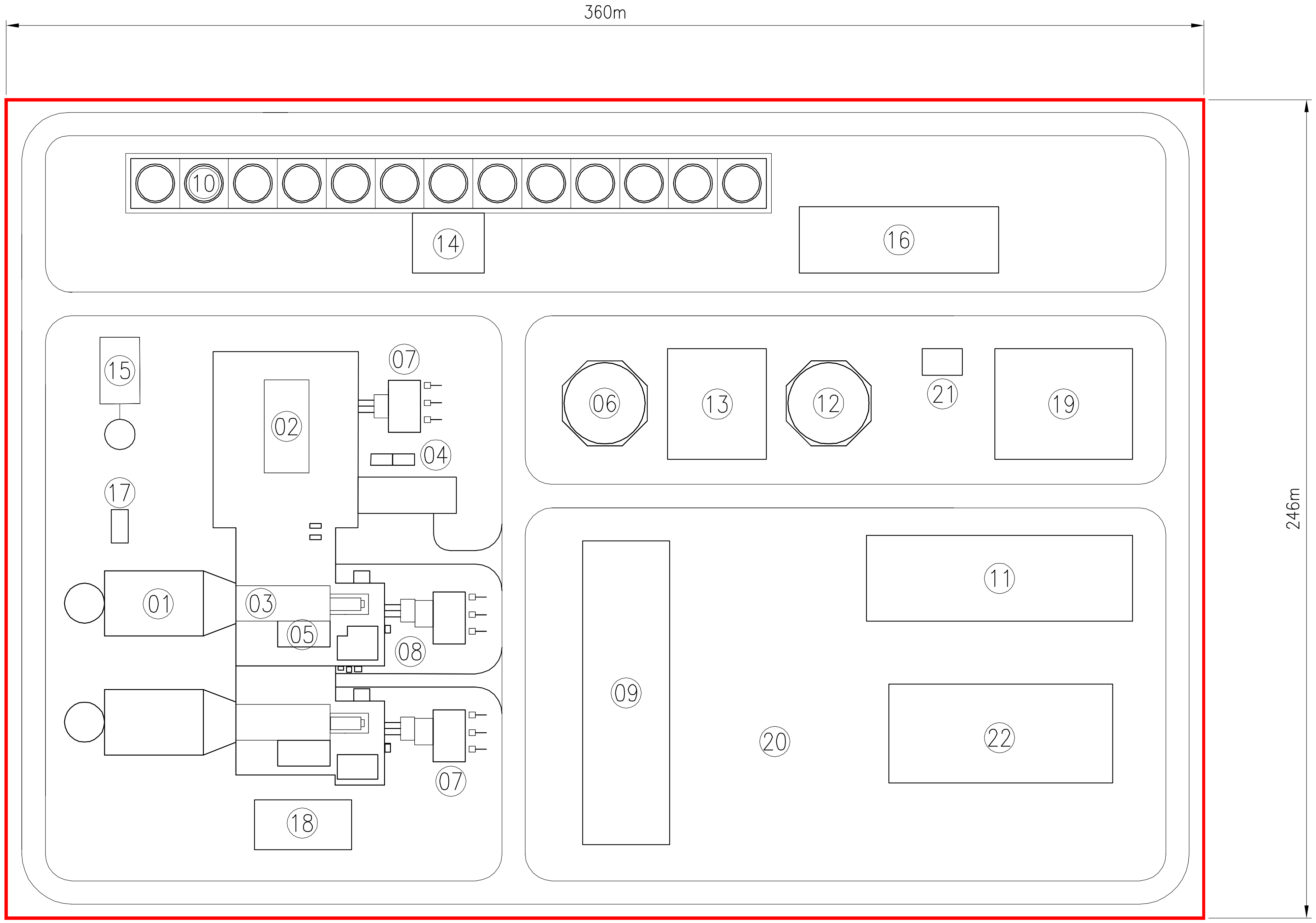
Tel: 44-(0)191-226-2000
Fax: 44-(0)191-226-2104

Client: IEA ENVIRONMENTAL PROJECTS LTD

Project: CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

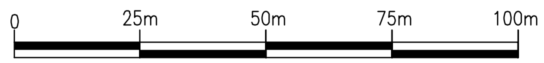
Title: REFORMING AND PRE-COMBUSTION CAPTURE PROVIDING HYDROGEN TO A REMOTE COMBINED CYCLE POWER PLANT
SHEET 1 OF 2

Drawn: MLC		Checked: IA	
Designed: MLC		Approved: GM	
Date: 02/11/2011	Scale: 1/2000	A3	Sheet: 1 OF 2
Project Number: 64225A	Drawing Number: -DSC-00014		Revision:



LEGEND

01 HEAT RECOVERY STEAM GENERATOR
02 STEAM TURBINE AREA
03 GAS TURBINE AREA
04 CO2 LOW PRESSURE STATION
05 GAS TURBINE INLET FILTER
06 DEMINERALIZED WATER STORAGE TANK
07 MAIN TRANSFORMER
08 AUXILIARY TRANSFORMER
09 GI SWITCHYARD
10 COOLING TOWERS
11 WAREHOUSE/MAINT./ADMIN
12 RAW WATER/ FIREWATER STORAGE TANK
13 WATER TREATMENT BUILDING
14 CW PUMPHOUSE
15 AUXILIARY BOILER
16 GAS CONDITIONING FACILITY
17 EMERGENCY DIESEL GENERATORS
18 CONTROL BUILDING
19 RAW-WATER PRE-TREATMENT
20 POSSIBLE LAYDOWN/OPEN STORAGE AREA
21 FIRE FIGHTING PUMPHOUSE
22 CAR PARKING



BAR SCALE 1:1500

Project Number: | Drawing Number: | Revision:

File Name: K:\Projects\64225A CO2 Capture at Gas Fired Power Plants Study\Z. Drawings\1. Current\CO2 Capture\00015.dwg

Login: Brindley, Barry
Plot Date: 23/03/2012 15:39:27

Rev	Date	Description	By	Chk	App	Notes:

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Fax: 44-(0)191-226-2104

Client:
IEA ENVIRONMENTAL PROJECTS LTD

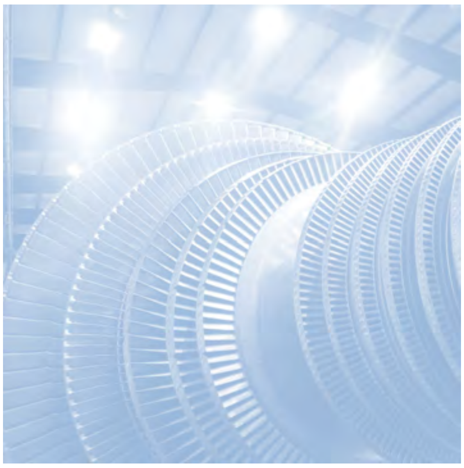
Project:
CO2 CAPTURE AT GAS FIRED POWER PLANTS STUDY

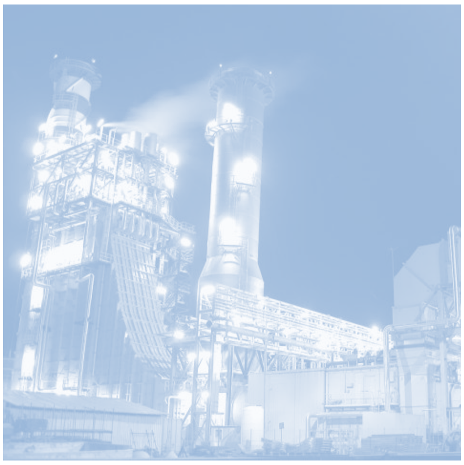
Title:
REFORMING AND PRE-COMBUSTION CAPTURE PROVIDING HYDROGEN TO A REMOTE COMBINED CYCLE POWER PLANT
SHEET 2 OF 2

Drawn: B.B.		Checked: IA	
Designed: ALM		Approved: GM	
Date: 02/11/2011	Scale: 1/1500	A3	Sheet: 2 0F 2
Project Number: 64225A	Drawing Number: -DSC-00015		Revision:

APPENDIX

D





PROCESS STREAM DATA AT FULL AND PART LOAD

APPENDIX D-1: PROCESS STREAM DATA AT 100% LOAD

Scenario 3: Post-Combustion Capture
PFD Drawing: 64225A-DSC-00002

	1	2	3	4	5	6	7	8	9
	Flue Gas to DCC	DCC water spray	DCC Spray water purge	Flue Gas to Absorber	Lean Solvent to Absorber	Wash Water to Absorber	Rich Solvent from Absorber Bottoms	Treated Flue gas from Absorber	Feed Stream to Stripper Column
Total Molar Flow, kmol/hr	85611.11	222935.81	4043.05	81721.12	69738.91	143741.75	69607.94	78701.53	69776.81
Total Mass Flow, tonne/hr	2430.00	4016.25	72.89	2357.11	1763.48	2589.55	1906.14	2214.41	1906.14
Total Volumetric Flow, m^3/hr	2599428.12	4032.63	74.03	1953548.94	1804.65	2596.23	2037.42	1988496.64	2120.15
Temperature, °C	97.05*	30.00	51.24	33.00	34.95	25.03	35.82	34.99	105.00
Pressure, barg	0.00	3.99	4.99	0.05	3.99	6.00	0.00	0.00	8.80
Mole Percent, %									
H_2O	8.82	100.00	99.89	4.78	83.55	100.00	79.71	5.64	79.71
MEA	0.00	0.00	0.00	0.00	14.16	0.00	13.55	0.00	13.55
CO_2	4.26	0.00	0.00	4.46	2.29	0.00	6.59	0.46	6.59
AR	0.85	0.00	0.00	0.89	0.00	0.00	0.00	0.91	0.00
O_2	11.80	0.00	0.03	12.28	0.00	0.00	0.04	12.65	0.04
N_2	74.27	0.00	0.07	77.60	0.00	0.00	0.10	80.34	0.10

Scenario 3: Post-Combustion Capture PFD Drawing: 64225A-DSC-00002			
	10 CO_2 to Compression Plant	11 LP Steam from Power plant to Reboiler	12 Lean Solvent from Stripper Column
Total Molar Flow, kmol/hr	3533.67	12114.98	69346.65
Total Mass Flow, tonne/hr	149.97	218.25	1756.20
Total Volumetric Flow, m^3/hr	59631.04	117336.38	1925.92
Temperature, °C	37.46	139.00	118.06
Pressure, barg	0.51	2.46	0.57
Mole Percent, %			
H_2O	4.32	100.00	83.47
MEA	0.00	0.00	14.23
CO_2	92.61	0.00	2.30
AR	0.07	0.00	0.00
O_2	0.89	0.00	0.00
N_2	2.12	0.00	0.00

Scenario 3: CO_2 Compression
PFD Drawing: 64225A-DSC-00003

	1	2	3	4	5	6	7	8	9
	CO_2 to Compression Plant	K101 Suction	V101 Condensate	Cooled K101 Discharge	K102 Suction	V102 Condensate	Cooled K102 Discharge	K103 Suction	V103 Condensate
Total Molar Flow, kmol/hr	3533.67	3533.67	0.00	3533.67	3422.42	111.25	3422.42	3396.87	25.54
Total Mass Flow, tonne/hr	149.97	149.97	0.00	149.97	147.96	2.00	147.96	147.50	0.46
Total Volumetric Flow, m^3/hr	59631.04	84679.09	0.00	28197.81	28195.78	2.03	9834.45	9833.99	0.47
Temperature, °C	37.46	37.80	0.00	30.00	30.00	30.00	30.00	30.00	30.00
Pressure, barg	0.51	0.06	0.06	2.00	2.00	2.00	7.32	7.32	7.32
Mole Percent, %									
H_2O	4.32	4.32	0.00	4.32	1.21	100.00	1.21	0.46	99.99
CO_2	92.61	92.61	0.00	92.61	95.62	0.00	95.62	96.34	0.01
AR	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07	0.00
O_2	0.89	0.89	0.00	0.89	0.91	0.00	0.91	0.92	0.00
N_2	2.12	2.12	0.00	2.12	2.19	0.00	2.19	2.21	0.00

Scenario 3: CO_2 Compression PFD Drawing: 64225A-DSC-00003								
	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	3396.87	3396.87	0.00	3396.87	3396.87	0.00	3382.22	3382.22
Total Mass Flow, tonne/hr	147.50	147.50	0.00	147.50	147.50	0.00	147.24	147.24
Total Volumetric Flow, m^3/hr	3227.77	3227.77	0.00	755.50	755.50	0.00	758.70	211.89
Temperature, °C	30.00	30.00	0.00	30.00	30.00	0.00	30.00	30.00
Pressure, barg	22.22	22.22	22.22	63.95	63.95	63.95	63.95	109.90
Mole Percent, %								
H_2O	0.46	0.46	0.00	0.46	0.46	0.00	0.03	0.03
CO_2	96.34	96.34	0.00	96.34	96.34	0.00	96.76	96.76
AR	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07
O_2	0.92	0.92	0.00	0.92	0.92	0.00	0.93	0.93
N_2	2.21	2.21	0.00	2.21	2.21	0.00	2.21	2.21

Scenario 4: Post Combustion Capture
PFD Drawing: 64225A-DSC-00007

	1	2	3	4	5	6	7	8	9
	Flue Gas to DCC #1	Flue Gas recycle to GT	DCC water spray	DCC Spray water purge	Flue Gas to Absorber	Lean Solvent to Absorber	Wash Water to Absorber	Rich Solvent from Absorber Bottoms	Treated Flue gas from Absorber
Total Molar Flow, kmol/hr	42020.55	38908.06	107750.00	2255.22	39828.02	70621.70	103389.00	70721.39	36560.81
Total Mass Flow, tonne/hr	1206.35	1150.20	1941.14	40.65	1165.70	1797.00	1862.58	1941.79	1020.88
Total Volumetric Flow, m^3/hr	1239320.00	936000.00	1949.06	41.28	952188.00	1844.91	1867.38	2076.43	923879.00
Temperature, °C	86.35	20.05	30.00	51.15	33.07	34.95	25.03	38.13	35.02
Pressure, barg	0.00	0.00	3.99	4.99	0.05	3.99	6.00	0.00	0.00
Mole Percent, %									
H_2O	9.52	2.31	100.00	99.91	4.80	83.25	100.00	79.61	5.61
MEA	0.00	0.00	0.00	0.00	0.00	14.16	0.00	13.53	0.00
CO_2	8.56	9.24	0.00	0.00	9.03	2.59	0.00	6.74	0.98
AR	0.92	1.00	0.00	0.00	0.97	0.00	0.00	0.00	1.04
O_2	4.20	4.54	0.00	0.01	4.40	0.00	0.00	0.01	4.74
N_2	76.79	82.91	0.00	0.08	80.80	0.00	0.00	0.10	87.62

Scenario 4: Post Combustion Capture PFD Drawing: 64225A-DSC-00007				
	10 Feed Stream to Stripper Column	11 CO_2 to Compression Plant	12 LP Steam from Power plant to Reboiler	13 Lean Solvent from Stripper Column
Total Molar Flow, kmol/hr	70721.39	3485.10	11208.42	70467.45
Total Mass Flow, tonne/hr	1941.79	147.76	201.92	1794.05
Total Volumetric Flow, m^3/hr	2159.27	59128.01	106114.00	1970.98
Temperature, °C	105.00	39.12	140.20	117.61
Pressure, barg	9.50	0.51	2.55	0.57
Mole Percent, %				
H_2O	79.61	4.72	100.00	83.22
MEA	13.53	0.00	0.00	14.18
CO_2	6.74	92.74	0.00	2.60
AR	0.00	0.07	0.00	0.00
O_2	0.01	0.31	0.00	0.00
N_2	0.10	2.16	0.00	0.00

Scenario 4: CO_2 Compression
PFD Drawing: 64225A-DSC-00003

	1	2	3	4	5	6	7	8	9
	CO_2 to Compression Plant	K101 Suction	V101 Condensate	Cooled K101 Discharge	K102 Suction	V102 Condensate	Cooled K102 Discharge	K103 Suction	V103 Condensate
Total Molar Flow, kmol/hr	3485.10	3485.10	0.00	3485.10	3361.13	123.97	3361.13	3336.05	25.09
Total Mass Flow, tonne/hr	147.76	147.76	0.00	147.76	145.52	2.23	145.52	145.07	0.45
Total Volumetric Flow, m^3/hr	59128.01	83510.75	0.00	27690.50	27688.24	2.26	9655.62	9655.16	0.46
Temperature, °C	39.12	37.80		30.00	30.00	30.00	30.00	30.00	30.00
Pressure, barg	0.51	0.06	0.06	2.00	2.00	2.00	7.32	7.32	7.32
Mole Percent, %									
H_2O	4.72	4.72	0.00	4.72	1.21	100.00	1.21	0.46	99.99
CO_2	92.74	92.74	0.00	92.74	96.16	0.00	96.16	96.88	0.01
AR	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07	0.00
O_2	0.31	0.31	0.00	0.31	0.32	0.00	0.32	0.32	0.00
N_2	2.16	2.16	0.00	2.16	2.24	0.00	2.24	2.26	0.00

Scenario 4: CO_2 Compression PFD Drawing: 64225A-DSC-00003								
	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	3336.05	3336.05	0.00	3336.05	3336.05	0.00	3321.68	3321.68
Total Mass Flow, tonne/hr	145.07	145.07	0.00	145.07	145.07	0.00	144.81	144.81
Total Volumetric Flow, m^3/hr	3166.85	3166.85	0.00	734.49	734.49	0.00	737.86	206.07
Temperature, °C	30.00	30.00		30.00	30.00		30.00	30.00
Pressure, barg	22.22	22.22	22.22	63.95	63.95	63.95	63.95	109.90
Mole Percent, %								
H_2O	0.46	0.46	0.00	0.46	0.46	0.00	0.03	0.03
CO_2	96.88	96.88	0.00	96.88	96.88	0.00	97.30	97.30
AR	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07
O_2	0.32	0.32	0.00	0.32	0.32	0.00	0.32	0.32
N_2	2.26	2.26	0.00	2.26	2.26	0.00	2.27	2.27

Scenario 5: Pre-Combustion Capture
PFD Drawing: 64225A-DSC-00005

	1	2	3	4	5	6	7	8	9
	Natural Gas to Process	Process Gas to Desulphurization Unit	Process Air from GT	Process Steam	Natural Gas to Furnace	H_2/N_2 gas to Furnace	Combustion Air to Furnace	ATR Process Gas Feed	ATR Process Air Feed
Total Molar Flow, kmol/hr	4094.02	4127.71	11860.32	8011.35	221.99	454.76	3154.20	12393.94	11860.32
Total Mass Flow, tonne/hr	73.77	74.27	343.57	144.33	4.00	6.00	91.00	218.60	343.57
Total Volumetric Flow, m^3/hr	1150.19	4625.35	37027.45	6837.51	2801.74	6637.12	112532.75	19279.82	17470.11
Temperature, °C	9.00	341.00	395.60	292.70	31.60	77.60	200.00	546.70	540.00
Pressure, barg	68.99	45.29	16.94	46.99	0.99	0.99	0.09	42.59	45.69
Mole Percent, %									
CO_2	2.00	2.00	0.00	0.00	2.00	2.30	0.00	0.70	0.00
CO	0.00	0.00	0.00	0.00	0.00	0.30	0.00	1.00	0.00
H_2	0.00	0.40	0.00	0.00	0.00	57.20	0.00	0.10	0.00
N_2	0.90	1.20	78.00	0.00	0.90	36.70	79.00	0.40	78.00
CH_4	89.00	88.30	0.00	0.00	89.00	3.10	0.00	34.10	0.00
AR	0.00	0.00	0.90	0.00	0.00	0.40	0.00	0.00	0.90
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2O	0.00	0.00	0.00	100.00	0.00	0.00	0.00	63.60	0.00
O2	0.00	0.00	21.00	0.00	0.00	0.00	21.00	0.00	21.00
C_2H_6	7.00	6.90	0.00	0.00	7.00	0.00	0.00	0.00	0.00
C_3H_8	1.00	1.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00
N-BUTANE	0.10	0.10	0.00	0.00	0.10	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 5: Pre-Combustion Capture PFD Drawing: 64225A-DSC-00005									
	10 Syn gas from ATR	11 Saturated Intermediate Pressure Steam	12 Superheated IP Steam to Power Plant	13 HT Shift Reactor Product	14 LT Shift Reactor Product	15 Syn gas to Absorber Column	16 Condensate from Syn gas knock out drum	17 Absorber bottoms (Rich Solvent)	18 Absorber Gas Recycle
Total Molar Flow, kmol/hr	29751.45	18822.40	10544.67	29751.45	29751.45	24886.63	4864.815	27079.424	1249.718
Total Mass Flow, tonne/hr	562.17	339.09	189.97	562.17	562.17	474.27	87.90	5606.98	35.91
Total Volumetric Flow, m^3/hr	71036.31	13943.81	8419.96	42594.65	33404.36	16054.50	94.83	5223.81	3101.82
Temperature, °C	911.80	265.00	287.00	419.00	251.00	20.00	20.00	2.00	0.10
Pressure, barg	40.63	49.39	49.09	39.64	38.11	36.81	36.81	36.81	7.99
Mole Percent, %									
CO_2	5.40	0.00	0.00	11.80	13.70	16.40	0.20	17.90	44.60
CO	8.70	0.00	0.00	2.40	0.40	0.50	0.00	0.00	0.50
H_2	28.70	0.00	0.00	35.10	37.00	44.30	0.00	1.30	24.00
N_2	31.30	0.00	0.00	31.30	31.30	37.40	0.00	1.60	27.90
CH_4	0.80	0.00	0.00	0.80	0.80	1.00	0.00	0.20	2.20
AR	0.40	0.00	0.00	0.40	0.40	0.50	0.00	0.10	0.80
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2O	24.70	100.00	100.00	18.30	16.40	0.10	99.80	8.50	0.00
O2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C_2H_6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C_3H_8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.40	0.00

Scenario 5: Pre-Combustion Capture PFD Drawing: 64225A-DSC-00005				
	19 CO_2 to Compression Plant	20 Lean Solvent to Absorber	21 H_2/N_2 gas to Gas Turbine	22 Furnace Flue Gas
Total Molar Flow, kmol/hr	3990.648	21839.054	20444.87	3710.68
Total Mass Flow, tonne/hr	171.02	5400.05	296.70	101.00
Total Volumetric Flow, m^3/hr	66247.17	4937.10	16311.21	117426.01
Temperature, °C	28.40	-10.00	77.90	131.70
Pressure, barg	0.49	36.20	36.31	0.05
Mole Percent, %				
CO_2	95.40	2.20	1.30	7.20
CO	0.00	0.00	0.60	0.00
H_2	1.20	0.00	52.50	0.00
N_2	2.10	0.00	44.10	71.70
CH_4	0.70	0.00	1.00	0.00
AR	0.20	0.00	0.50	0.10
NH_3	0.00	0.00	0.00	0.00
H_2O	0.40	10.50	0.00	20.00
O2	0.00	0.00	0.00	1.10
C_2H_6	0.00	0.00	0.00	0.00
C_3H_8	0.00	0.00	0.00	0.00
N-BUTANE	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00
DEPG	0.00	87.30	0.00	0.00

Scenario 5: CO_2 Compression
PFD Drawing: 64225A-DSC-00003

	1 CO_2 to Compression Plant	2 K101 Suction	3 V101 Condensate	4 Cooled K101 Discharge	5 K102 Suction	6 V102 Condensate	7 Cooled K102 Discharge	8 K103 Suction	9 V103 Condensate
Total Molar Flow, kmol/hr	3990.65	3990.65	0.00	3990.65	3990.65	0.00	3990.65	3990.65	0.00
Total Mass Flow, tonne/hr	171.02	171.02	0.00	171.02	171.02	0.00	171.02	171.02	0.00
Total Volumetric Flow, m^3/hr	66247.17	70985.20	0.00	29617.51	30536.17	0.00	12130.30	12286.35	0.00
Temperature, °C	28.40	28.50		30.00	29.90		30.00	29.90	
Pressure, barg	0.49	0.39	0.39	2.33	2.23	2.23	6.95	6.85	6.85
Mole Percent, %									
CO_2	95.40	95.40	0.00	95.40	95.40	0.00	95.40	95.40	0.00
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2	1.20	1.20	0.00	1.20	1.20	0.00	1.20	1.20	0.00
N_2	2.10	2.10	0.00	2.10	2.10	0.00	2.10	2.10	0.00
CH_4	0.70	0.70	0.00	0.70	0.70	0.00	0.70	0.70	0.00
AR	0.20	0.20	0.00	0.20	0.20	0.00	0.20	0.20	0.00
H_2O	0.40	0.40	0.00	0.40	0.40	0.00	0.40	0.40	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 5: CO_2 Compression PFD Drawing: 64225A-DSC-00003								
	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	3990.65	3985.98	4.67	3985.98	3982.06	3.91	3977.12	3977.12
Total Mass Flow, tonne/hr	171.02	170.93	0.08	170.93	170.86	0.07	170.77	170.77
Total Volumetric Flow, m^3/hr	4475.52	4518.98	0.09	1281.88	1291.66	0.07	1303.80	261.34
Temperature, °C	30.00	31.10	31.10	30.00	30.50	30.50	30.00	30.00
Pressure, barg	19.13	19.03	19.03	52.80	52.70	52.70	52.20	108.99
Mole Percent, %								
CO_2	95.40	95.50	0.00	95.50	95.60	0.00	95.70	95.70
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2	1.20	1.20	0.00	1.20	1.20	0.00	1.20	1.20
N_2	2.10	2.10	0.00	2.10	2.10	0.00	2.10	2.10
CH_4	0.70	0.70	0.00	0.70	0.70	0.00	0.70	0.70
AR	0.20	0.20	0.00	0.20	0.20	0.00	0.20	0.20
H_2O	0.40	0.20	100.00	0.20	0.10	100.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 6: Pre-Combustion Capture
PFD Drawing: 64225A-DSC-00008 and 00009

	1 Natural Gas to Process	2 Process Gas to Desulphurization Unit	3 Process Air from compressor	4 Process Steam	5 Natural Gas to Furnace	6 H_2/N_2 gas to Furnace	7 Combustion Air to Furnace	8 ATR Process Gas Feed	9 ATR Process Air Feed
Total Molar Flow, kmol/hr	4084.58	4118.27	11833.00	8011.35	221.99	454.76	3154.20	12383.92	11833.00
Total Mass Flow, tonne/hr	73.60	74.10	342.78	144.33	4.00	6.00	91.00	218.43	342.78
Total Volumetric Flow, m^3/hr	1147.53	4614.77	13256.00	6932.03	2685.72	6502.17	112533.00	19263.80	17429.87
Temperature, °C	9.00	341.00	346.70	297.77	19.15	70.44	200.00	546.70	540.00
Pressure, barg	68.99	45.29	45.99	46.99	0.99	0.99	0.09	42.59	45.69
Mole Percent, %									
CO_2	2.00	2.00	0.03	0.00	2.00	2.30	0.00	0.70	0.03
CO	0.00	0.00	0.00	0.00	0.00	0.29	0.00	1.00	0.00
H_2	0.00	0.42	0.00	0.00	0.00	57.17	0.00	0.10	0.00
N_2	0.89	1.24	78.03	0.00	0.89	36.67	79.00	0.40	78.03
CH_4	89.00	88.28	0.00	0.00	89.00	3.13	0.00	34.10	0.00
AR	0.00	0.00	0.95	0.00	0.00	0.43	0.00	0.00	0.95
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2O	0.00	0.00	0.00	100.00	0.00	0.01	0.00	63.70	0.00
O2	0.00	0.00	20.99	0.00	0.00	0.00	21.00	0.00	20.99
C_2H_6	7.00	6.94	0.00	0.00	7.00	0.00	0.00	0.00	0.00
C_3H_8	1.00	0.99	0.00	0.00	1.00	0.00	0.00	0.00	0.00
N-BUTANE	0.10	0.10	0.00	0.00	0.10	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-PENTAN	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 6: Pre-Combustion Capture PFD Drawing: 64225A-DSC-00008 and 00009									
	10	11	12	13	14	15	16	17	18
	Syn gas from ATR	Saturated Intermediate Pressure Steam	IP Steam to Steam Turbine Generator	HT Shift Reactor Product	LT Shift Reactor Product	Syn gas to Absorber Column	Condensate from Syn gas knock out drum	Absorber bottoms (Rich Solvent)	Absorber Gas Recycle
Total Molar Flow, kmol/hr	29701.41	18798.61	7237.50	29701.41	29701.41	24825.11	4876.30	27064.88	1247.65
Total Mass Flow, tonne/hr	561.21	338.66	130.39	561.21	561.21	473.10	88.10	5606.31	35.80
Total Volumetric Flow, m^3/hr	70905.52	13926.18	5361.60	42500.31	33493.36	16014.93	95.05	5223.03	3096.67
Temperature, °C	911.60	265.00	265.00	418.70	253.20	20.00	20.00	2.00	0.10
Pressure, barg	40.63	49.39	49.39	39.64	38.11	36.81	36.81	36.81	7.99
Mole Percent, %									
CO_2	5.40	0.00	0.00	11.80	13.70	16.30	0.20	17.80	44.50
CO	8.70	0.00	0.00	2.30	0.40	0.50	0.00	0.00	0.50
H_2	28.70	0.00	0.00	35.10	37.00	44.20	0.00	1.30	24.10
N_2	31.30	0.00	0.00	31.30	31.30	37.40	0.00	1.60	27.90
CH_4	0.80	0.00	0.00	0.80	0.80	1.00	0.00	0.20	2.20
AR	0.40	0.00	0.00	0.40	0.40	0.50	0.00	0.10	0.80
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2O	24.70	100.00	100.00	18.40	16.40	0.10	99.80	8.50	0.00
O2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C_2H_6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C_3H_8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.40	0.00

Scenario 6: Pre-Combustion Capture PFD Drawing: 64225A-DSC-00008 and 00009				
	19	20	21	22
	CO_2 to Compression Plant	Lean Solvent to Absorber	H_2/N_2 gas at Storage Compressor Discharge	Furnace Flue Gas
Total Molar Flow, kmol/hr	3977.55	21839.69	20395.96	3710.68
Total Mass Flow, tonne/hr	170.43	5400.08	296.09	101.00
Total Volumetric Flow, m^3/hr	66041.85	4937.12	9169.15	135988.00
Temperature, °C	28.50	-10.00	56.22	195.50
Pressure, barg	0.49	36.20	62.00	0.05
Mole Percent, %				
CO_2	95.40	2.20	1.27	7.19
CO	0.10	0.00	0.61	0.00
H_2	1.20	0.00	52.47	0.00
N_2	2.10	0.00	44.14	71.70
CH_4	0.70	0.00	0.99	0.00
AR	0.20	0.00	0.51	0.05
NH_3	0.00	0.00	0.00	0.00
H_2O	0.40	10.50	0.01	19.95
O2	0.00	0.00	0.00	1.10
C_2H_6	0.00	0.00	0.00	0.00
C_3H_8	0.00	0.00	0.00	0.00
N-BUTANE	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00
DEPG	0.00	87.30	0.00	0.00

Scenario 6: Compression Unit
PFD Drawing: 64225A-DSC-00009

	1	2	3	4	5	6	7	8	9
	CO_2 to Compression Plant	K101 Suction	V101 Condensate	Cooled K101 Discharge	K102 Suction	V102 Condensate	Cooled K102 Discharge	K103 Suction	V103 Condensate
Total Molar Flow, kmol/hr	3977.55	3977.55	0.00	3977.55	3977.55	0.00	3977.55	3977.55	0.00
Total Mass Flow, tonne/hr	170.43	170.43	0.00	170.43	170.43	0.00	170.43	170.43	0.00
Total Volumetric Flow, m^3/hr	66041.85	70765.21	0.00	29520.50	30436.15	0.00	12090.70	12246.24	0.00
Temperature, °C	28.50	28.50		30.00	29.90		30.00	29.90	
Pressure, barg	0.49	0.39	0.39	2.33	2.23	2.23	6.95	6.85	6.85
Mole Percent, %									
CO_2	95.40	95.40	0.00	95.40	95.40	0.00	95.40	95.40	0.00
CO	0.10	0.10	0.00	0.10	0.10	0.00	0.10	0.10	0.00
H_2	1.20	1.20	0.00	1.20	1.20	0.00	1.20	1.20	0.00
N_2	2.10	2.10	0.00	2.10	2.10	0.00	2.10	2.10	0.00
CH_4	0.70	0.70	0.00	0.70	0.70	0.00	0.70	0.70	0.00
AR	0.20	0.20	0.00	0.20	0.20	0.00	0.20	0.20	0.00
H_2O	0.40	0.40	0.00	0.40	0.40	0.00	0.40	0.40	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 6: Compression Unit
PFD Drawing: 64225A-DSC-00009

	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	3977.55	3972.89	4.66	3972.89	3968.98	3.90	3964.06	3964.06
Total Mass Flow, tonne/hr	170.43	170.35	0.08	170.35	170.27	0.07	170.19	170.19
Total Volumetric Flow, m^3/hr	4461.08	4504.41	0.09	1278.07	1287.82	0.07	1287.59	261.20
Temperature, °C	30.00	31.10	31.10	30.00	30.50	30.50	30.50	30.00
Pressure, barg	19.13	19.03	19.03	52.80	52.70	52.70	52.70	108.69
Mole Percent, %								
CO_2	95.40	95.50	0.00	95.50	95.60	0.00	95.70	95.70
CO	0.10	0.10	0.00	0.10	0.10	0.00	0.10	0.10
H_2	1.20	1.20	0.00	1.20	1.20	0.00	1.20	1.20
N_2	2.10	2.10	0.00	2.10	2.10	0.00	2.10	2.10
CH_4	0.70	0.70	0.00	0.70	0.70	0.00	0.70	0.70
AR	0.20	0.20	0.00	0.20	0.20	0.00	0.20	0.20
H_2O	0.40	0.20	100.00	0.20	0.10	100.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

APPENDIX D-2: PROCESS STREAM DATA AT 40% GT LOAD

Scenario 3: Post-Combustion Capture
PFD Drawing: 64225A-DSC-00002

	1	2	3	4	5	6	7	8	9
	Flue Gas to DCC	DCC water spray	DCC Spray water purge	Flue Gas to Absorber	Lean Solvent to Absorber	Wash Water to Absorber	Rich Solvent from Absorber Bottoms	Treated Flue gas from Absorber	Feed Stream to Stripper Column
Total Molar Flow, kmol/hr	52964.69	126304.00	1900.15	51160.12	37755.95	80230.52	37651.79	49578.97	37739.11
Total Mass Flow, tonne/hr	1507.10	2275.40	34.26	1472.84	954.73	1445.38	1030.64	1396.91	1030.64
Total Volumetric Flow, m^3/hr	1555140.00	2284.69	34.76	1223020.00	977.02	1449.10	1101.56	1252690.00	1146.39
Temperature, °C	84.85	30.00	48.39	33.00	34.95	25.03	35.62	34.99	105.00
Pressure, barg	0.00	3.99	4.99	0.05	3.99	6.00	0.00	0.00	8.80
Mole Percent, %									
H_2O	7.74	100.00	99.88	4.78	83.55	100.00	79.73	5.60	79.73
MEA	0.00	0.00	0.00	0.00	14.16	0.00	13.57	0.00	13.57
CO_2	3.69	0.00	0.00	3.81	2.29	0.00	6.55	0.39	6.55
AR	0.90	0.00	0.00	0.92	0.00	0.00	0.00	0.95	0.00
O_2	13.00	0.00	0.04	13.37	0.00	0.00	0.05	13.70	0.05
N_2	74.67	0.00	0.08	77.11	0.00	0.00	0.10	79.35	0.10

Scenario 3: Post-Combustion Capture PFD Drawing: 64225A-DSC-00002			
	10 CO_2 to Compression Plant	11 LP Steam from Power plant to Reboiler	12 Lean Solvent from Stripper Column
Total Molar Flow, kmol/hr	1866.92	6550.00	37538.99
Total Mass Flow, tonne/hr	79.92	118.00	950.73
Total Volumetric Flow, m^3/hr	30711.48	63438.22	1042.62
Temperature, °C	29.75	139.00	118.06
Pressure, barg	0.51	2.46	0.57
Mole Percent, %			
H_2O	2.81	100.00	83.46
MEA	0.00	0.00	14.23
CO_2	93.96	0.00	2.30
AR	0.07	0.00	0.00
O_2	0.99	0.00	0.00
N_2	2.17	0.00	0.00

Scenario 3: CO_2 Compression
PFD Drawing: 64225A-DSC-00003

	1	2	3	4	5	6	7	8	9
	CO_2 to Compression Plant	K101 Suction	V101 Condensate	Cooled K101 Discharge	K102 Suction	V102 Condensate	Cooled K102 Discharge	K103 Suction	V103 Condensate
Total Molar Flow, kmol/hr	1866.92	1866.92	0.00	1866.92	1836.61	30.31	1836.61	1822.90	13.71
Total Mass Flow, tonne/hr	79.92	79.92	0.00	79.92	79.38	0.55	79.38	79.13	0.25
Total Volumetric Flow, m^3/hr	30711.48	44742.15	0.00	15131.88	15131.33	0.55	5277.90	5277.65	0.25
Temperature, °C	29.75	29.50	0.00	30.00	30.00	30.00	30.00	30.00	30.00
Pressure, barg	0.51	0.06	0.06	2.00	2.00	2.00	7.32	7.32	7.32
Mole Percent, %									
H_2O	2.81	2.81	0.00	2.81	1.21	100.00	1.21	0.46	99.99
CO_2	93.96	93.96	0.00	93.96	95.51	0.00	95.51	96.23	0.01
AR	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07	0.00
O_2	0.99	0.99	0.00	0.99	1.01	0.00	1.01	1.02	0.00
N_2	2.17	2.17	0.00	2.17	2.20	0.00	2.20	2.22	0.00

Scenario 3: CO_2 Compression PFD Drawing: 64225A-DSC-00003								
	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	1822.90	1822.90	0.00	1822.90	1822.90	0.00	1815.54	1815.54
Total Mass Flow, tonne/hr	79.13	79.13	0.00	79.13	79.13	0.00	79.00	79.00
Total Volumetric Flow, m^3/hr	1732.52	1732.52	0.00	406.30	406.30	0.00	407.89	113.90
Temperature, °C	30.00	30.00		30.00	30.00		30.00	30.00
Pressure, barg	22.22	22.22	22.22	63.95	63.95	63.95	63.95	109.90
Mole Percent, %								
H_2O	0.46	0.46	0.00	0.46	0.46	0.00	0.06	0.06
CO_2	96.23	96.23	0.00	96.23	96.23	0.00	96.62	96.62
AR	0.07	0.07	0.00	0.07	0.07	0.00	0.07	0.07
O_2	1.02	1.02	0.00	1.02	1.02	0.00	1.02	1.02
N_2	2.22	2.22	0.00	2.22	2.22	0.00	2.23	2.23

Scenario 4: Post Combustion Capture
PFD Drawing: 64225A-DSC-00007

	1 Flue Gas to DCC #1	2 Flue Gas recycle to GT	3 DCC water spray	4 DCC Spray water purge	5 Flue Gas to Absorber	6 Lean Solvent to Absorber	7 Wash Water to Absorber	8 Rich Solvent from Absorber Bottoms	9 Treated Flue gas from Absorber
Total Molar Flow, kmol/hr	27005.98	25279.60	79932.15	1344.75	25715.97	38896.88	61066.75	38742.95	24112.27
Total Mass Flow, tonne/hr	775.95	745.90	1440.00	24.24	751.71	989.75	1100.14	1066.62	674.81
Total Volumetric Flow, m^3/hr	781258.00	599040.00	1445.87	24.58	609104.00	1016.14	1102.97	1139.84	609390.00
Temperature, °C	79.50	15.59	30.00	46.78	30.22	34.95	25.03	34.72	35.06
Pressure, barg	0.00	0.00	3.99	4.99	0.05	3.99	6.00	0.00	0.00
Mole Percent, %									
H_2O	8.34	1.75	100.00	99.89	4.08	83.25	100.00	79.46	5.63
MEA	0.00	0.00	0.00	0.00	0.00	14.16	0.00	13.59	0.00
CO_2	7.41	7.96	0.00	0.00	7.78	2.59	0.00	6.81	0.83
AR	0.92	0.99	0.00	0.00	0.96	0.00	0.00	0.00	1.01
O_2	6.43	6.87	0.00	0.02	6.70	0.00	0.00	0.02	7.06
N_2	76.89	82.43	0.00	0.08	80.48	0.00	0.00	0.11	85.47

Scenario 4: Post Combustion Capture PFD Drawing: 64225A-DSC-00007				
	10 Feed Stream to Stripper Column	11 CO_2 to Compression Plant	12 LP Steam from Power plant to Reboiler	13 Lean Solvent from Stripper Column
Total Molar Flow, kmol/hr	38742.98	2021.88	6167.08	38881.32
Total Mass Flow, tonne/hr	1066.62	83.79	111.10	1066.62
Total Volumetric Flow, m^3/hr	1139.67	35526.07	58385.63	1322.93
Temperature, °C	35.01	50.13	140.20	105.00
Pressure, barg	10.30	0.51	2.55	8.80
Mole Percent, %				
H_2O	79.46	8.31	100.00	79.53
MEA	13.59	0.00	0.00	13.61
CO_2	6.81	88.95	0.00	6.75
AR	0.00	0.07	0.00	0.00
O_2	0.02	0.48	0.00	0.02
N_2	0.11	2.19	0.00	0.08

Scenario 4: CO_2 Compression
PFD Drawing: 64225A-DSC-00003

	1 CO_2 to Compression Plant	2 K101 Suction	3 V101 Condensate	4 Cooled K101 Discharge	5 K102 Suction	6 V102 Condensate	7 Cooled K102 Discharge	8 K103 Suction	9 V103 Condensate
Total Molar Flow, kmol/hr	2021.88	1955.73	66.16	1955.73	1876.53	79.19	1876.53	1862.53	14.01
Total Mass Flow, tonne/hr	83.79	82.59	1.19	82.59	81.17	1.43	81.17	80.92	0.25
Total Volumetric Flow, m^3/hr	35526.07	46863.13	1.22	15460.80	15459.36	1.44	5391.71	5391.46	0.26
Temperature, °C	50.13	37.80	37.80	30.00	30.00	30.00	30.00	30.00	30.00
Pressure, barg	0.51	0.06	0.06	2.00	2.00	2.00	7.32	7.32	7.32
Mole Percent, %									
H_2O	8.31	5.21	100.00	5.21	1.21	100.00	1.21	0.46	99.99
CO_2	88.95	91.96	0.00	91.96	95.84	0.00	95.84	96.56	0.01
AR	0.07	0.07	0.00	0.07	0.08	0.00	0.08	0.08	0.00
O_2	0.48	0.50	0.00	0.50	0.52	0.00	0.52	0.52	0.00
N_2	2.19	2.26	0.00	2.26	2.36	0.00	2.36	2.37	0.00

Scenario 4: CO_2 Compression PFD Drawing: 64225A-DSC-00003								
	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	1862.53	1862.53	0.00	1862.53	1862.53	0.00	1854.98	1854.98
Total Mass Flow, tonne/hr	80.92	80.92	0.00	80.92	80.92	0.00	80.78	80.78
Total Volumetric Flow, m^3/hr	1769.16	1769.16	0.00	412.76	412.76	0.00	414.45	115.78
Temperature, °C	30.00	30.00		30.00	30.00		30.00	30.00
Pressure, barg	22.22	22.22	22.22	63.95	63.95	63.95	63.95	109.90
Mole Percent, %								
H_2O	0.46	0.46	0.00	0.46	0.46	0.00	0.06	0.06
CO_2	96.56	96.56	0.00	96.56	96.56	0.00	96.96	96.96
AR	0.08	0.08	0.00	0.08	0.08	0.00	0.08	0.08
O_2	0.52	0.52	0.00	0.52	0.52	0.00	0.52	0.52
N_2	2.37	2.37	0.00	2.37	2.37	0.00	2.38	2.38

Scenario 5: Pre-Combustion
PFD Drawing: 64225A-DSC-00005

	1	2	3	4	5	6	7	8	9
	Natural Gas to Process	Process Gas to Desulphurization Unit	Process Air from GT	Process Steam	Natural Gas to Furnace	H_2/N_2 gas to Furnace	Combustion Air to Furnace	ATR Process Gas Feed	ATR Process Air Feed
Total Molar Flow, kmol/hr	2387.16	2405.88	6843.20	4690.84	138.74	227.38	1867.05	7245.34	6843.20
Total Mass Flow, tonne/hr	43.01	43.29	198.24	84.51	2.50	3.00	53.87	127.80	198.24
Total Volumetric Flow, m^3/hr	670.66	2695.92	31459.75	3718.03	1892.10	2952.32	66610.72	11270.21	10079.95
Temperature, °C	9.00	341.00	366.00	267.50	55.80	38.90	200.00	546.70	540.00
Pressure, barg	68.99	45.29	10.61	46.99	0.99	0.99	0.09	42.59	45.69
Mole Percent, %									
CO_2	2.00	2.00	0.00	0.00	2.00	2.30	0.00	0.66	0.00
CO	0.00	0.00	0.00	0.00	0.00	0.30	0.00	1.03	0.00
H_2	0.00	0.40	0.00	0.00	0.00	57.20	0.00	0.13	0.00
N_2	0.90	1.20	78.00	0.00	0.90	36.70	79.00	0.41	78.00
CH_4	89.00	88.30	0.00	0.00	89.00	3.10	0.00	34.05	0.00
AR	0.00	0.00	0.90	0.00	0.00	0.40	0.00	0.00	0.90
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2O	0.00	0.00	0.00	100.00	0.00	0.00	0.00	63.72	0.00
O2	0.00	0.00	21.00	0.00	0.00	0.00	21.00	0.00	21.00
C_2H_6	7.00	6.90	0.00	0.00	7.00	0.00	0.00	0.00	0.00
C_3H_8	1.00	1.00	0.00	0.00	1.00	0.00	0.00	0.00	0.00
N-BUTANE	0.10	0.10	0.00	0.00	0.10	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 5: Pre-Combustion PFD Drawing: 64225A-DSC-00005									
	10 Syn gas from ATR	11 Saturated Intermediate Pressure Steam	12 Superheated IP Steam to Power Plant	13 HT Shift Reactor Product	14 LT Shift Reactor Product	15 Syn gas to Absorber Column	16 Condensate from Syn gas knock out drum	17 Absorber bottoms (Rich Solvent)	18 Absorber Gas Recycle
Total Molar Flow, kmol/hr	17285.27	11340.65	6039.218	17285.27	17285.27	14469.48	2815.79	18790.31	825.29
Total Mass Flow, tonne/hr	326.03	204.31	108.798	326.03	326.03	275.16	50.88	3973.41	21.82
Total Volumetric Flow, m^3/hr	41049.74	8341.22	4652.405	23639.46	18245.68	9333.71	54.89	3696.16	2047.25
Temperature, °C	905.42	262.80	275	388.14	220.44	20.00	20.00	0.70	-1.20
Pressure, barg	40.63	49.39	49.087	39.64	38.11	36.81	36.81	36.81	7.99
Mole Percent, %									
CO_2	5.49	0.00	0.00	12.26	13.90	16.60	0.20	15.40	36.80
CO	8.64	0.00	0.00	1.86	0.23	0.30	0.00	0.00	0.30
H_2	28.84	0.00	0.00	35.62	37.25	44.50	0.00	1.40	27.90
N_2	31.06	0.00	0.00	31.06	31.06	37.10	0.00	1.80	31.60
CH_4	0.87	0.00	0.00	0.87	0.87	1.00	0.00	0.20	2.50
AR	0.38	0.00	0.00	0.38	0.38	0.40	0.00	0.10	0.80
NH_3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2O	24.73	100.00	100.00	17.95	16.32	0.10	99.80	8.80	0.00
O2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C_2H_6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C_3H_8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.30	0.00

Scenario 5: Pre-Combustion PFD Drawing: 64225A-DSC-00005				
	19	20	21	22
	CO_2 to Compression Plant	Lean Solvent to Absorber	H_2/N_2 gas to Gas Turbine	Furnace Flue Gas
Total Molar Flow, kmol/hr	2395.63	15569.39	11829.151	2174.33
Total Mass Flow, tonne/hr	101.57	3850.02	170.067	59.37
Total Volumetric Flow, m^3/hr	40426.76	3519.95	8414.046	77052.18
Temperature, °C	33.30	-10.00	40.1	180.00
Pressure, barg	0.49	36.20	36.31	0.05
Mole Percent, %				
CO_2	93.60	2.20	1.30	7.50
CO	0.00	0.00	0.30	0.00
H_2	1.80	0.00	53.00	0.00
N_2	3.00	0.00	43.90	71.70
CH_4	1.00	0.00	1.00	0.00
AR	0.20	0.00	0.50	0.00
NH_3	0.00	0.00	0.00	0.00
H_2O	0.40	10.50	0.00	19.60
O2	0.00	0.00	0.00	1.10
C_2H_6	0.00	0.00	0.00	0.00
C_3H_8	0.00	0.00	0.00	0.00
N-BUTANE	0.00	0.00	0.00	0.00
I-BUTANE	0.00	0.00	0.00	0.00
I-PENTAN	0.00	0.00	0.00	0.00
N-PENTAN	0.00	0.00	0.00	0.00
N-HEXANE	0.00	0.00	0.00	0.00
N-HEPTNE	0.00	0.00	0.00	0.00
SULFUR	0.00	0.00	0.00	0.00
DEPG	0.00	87.30	0.00	0.00

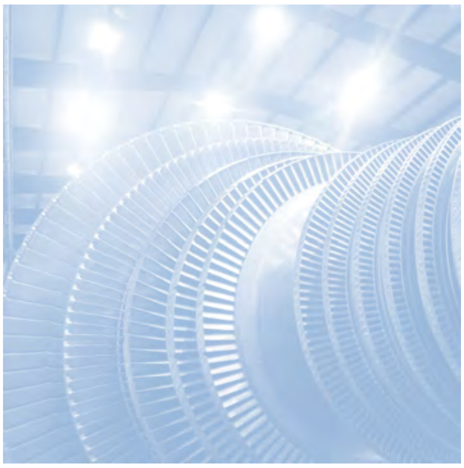
Scenario 5: CO_2 Compression
PFD Drawing: 64225A-DSC-00003

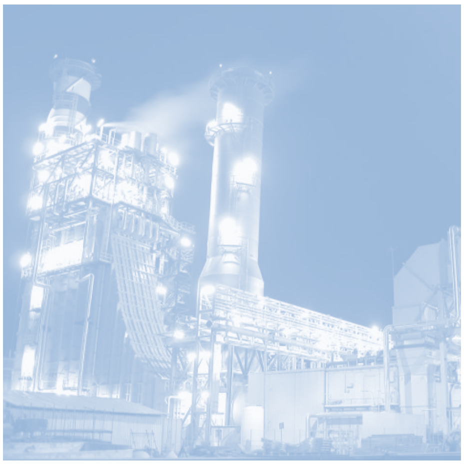
	1	2	3	4	5	6	7	8	9
	CO_2 to Compression Plant	K101 Suction	V101 Condensate	Cooled K101 Discharge	K102 Suction	V102 Condensate	Cooled K102 Discharge	K103 Suction	V103 Condensate
Total Molar Flow, kmol/hr	2395.63	2395.63	0.00	2395.63	2395.63	0.00	2395.63	2395.63	0.00
Total Mass Flow, tonne/hr	101.57	101.57	0.00	101.57	101.57	0.00	101.57	101.57	0.00
Total Volumetric Flow, m^3/hr	40426.76	43318.20	0.00	17787.44	18339.05	0.00	7289.94	7383.67	0.00
Temperature, °C	33.30	33.30		30.00	29.90		30.00	29.90	
Pressure, barg	0.49	0.39	0.39	2.33	2.23	2.23	6.95	6.85	6.85
Mole Percent, %									
CO_2	93.60	93.60	0.00	93.60	93.60	0.00	93.60	93.60	0.00
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2	1.80	1.80	0.00	1.80	1.80	0.00	1.80	1.80	0.00
N_2	3.00	3.00	0.00	3.00	3.00	0.00	3.00	3.00	0.00
CH_4	1.00	1.00	0.00	1.00	1.00	0.00	1.00	1.00	0.00
AR	0.20	0.20	0.00	0.20	0.20	0.00	0.20	0.20	0.00
H_2O	0.40	0.40	0.00	0.40	0.40	0.00	0.40	0.40	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Scenario 5: CO_2 Compression PFD Drawing: 64225A-DSC-00003								
	10 Cooled K103 Discharge	11 K104 Suction	12 V104 Condensate	13 Cooled K104 Discharge	14 CO_2 to TEG unit	15 V105 Condensate	16 K105 Suction	17 Cooled K105 Discharge
Total Molar Flow, kmol/hr	2395.63	2392.39	3.24	2392.39	2389.96	2.43	2387.01	2387.01
Total Mass Flow, tonne/hr	101.57	101.51	0.06	101.51	101.47	0.04	101.41	101.41
Total Volumetric Flow, m^3/hr	2695.57	2723.62	0.06	783.62	789.65	0.04	797.02	166.91
Temperature, °C	30.00	31.30	31.30	30.00	30.50	30.50	30.00	30.00
Pressure, barg	19.13	19.03	19.03	52.80	52.70	52.70	52.20	108.99
Mole Percent, %								
CO_2	93.60	93.80	0.00	93.80	93.90	0.00	94.00	94.00
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2	1.80	1.80	0.00	1.80	1.80	0.00	1.80	1.80
N_2	3.00	3.00	0.00	3.00	3.00	0.00	3.00	3.00
CH_4	1.00	1.00	0.00	1.00	1.00	0.00	1.00	1.00
AR	0.20	0.20	0.00	0.20	0.20	0.00	0.20	0.20
H_2O	0.40	0.20	100.00	0.20	0.10	100.00	0.00	0.00
DEPG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

APPENDIX

E

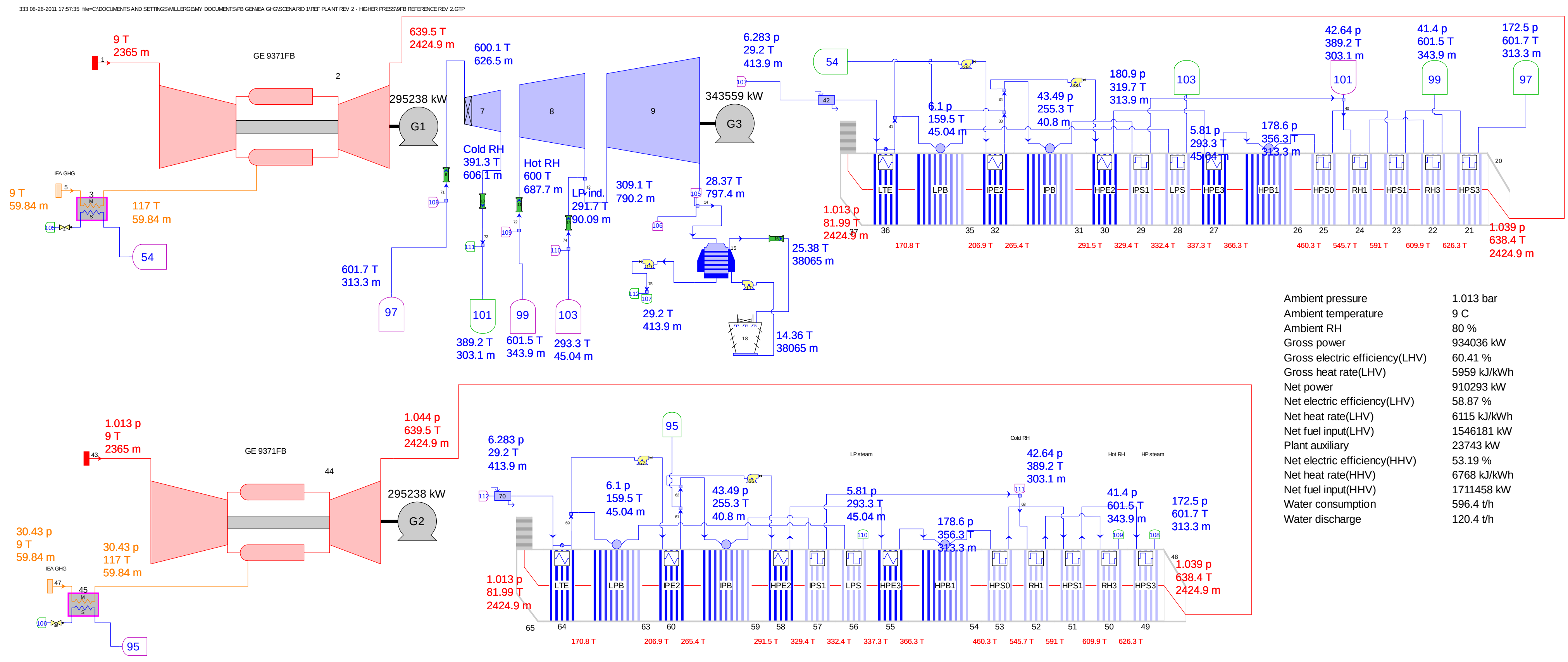




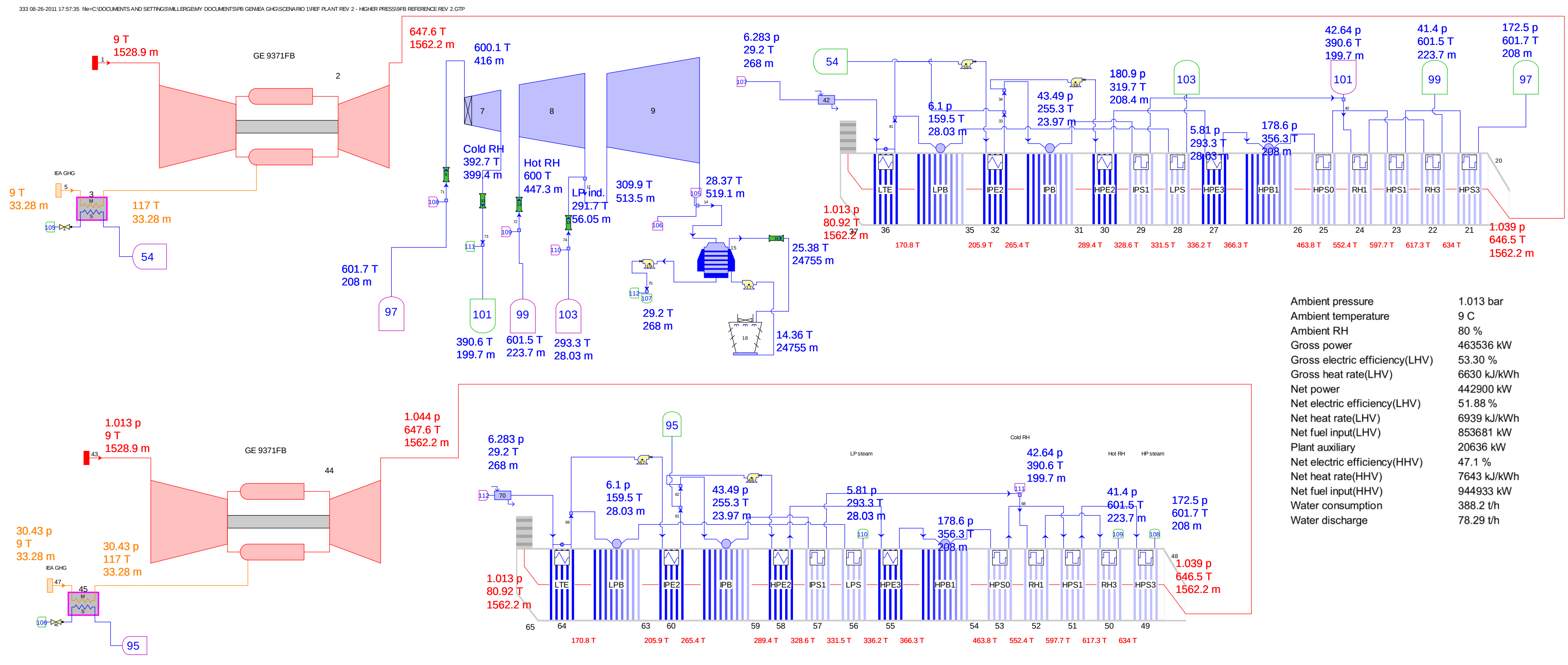
THERMOFLEX SUMMARY OUTPUTS

APPENDIX E-1: THERMOFLEX SUMMARY OUTPUTS

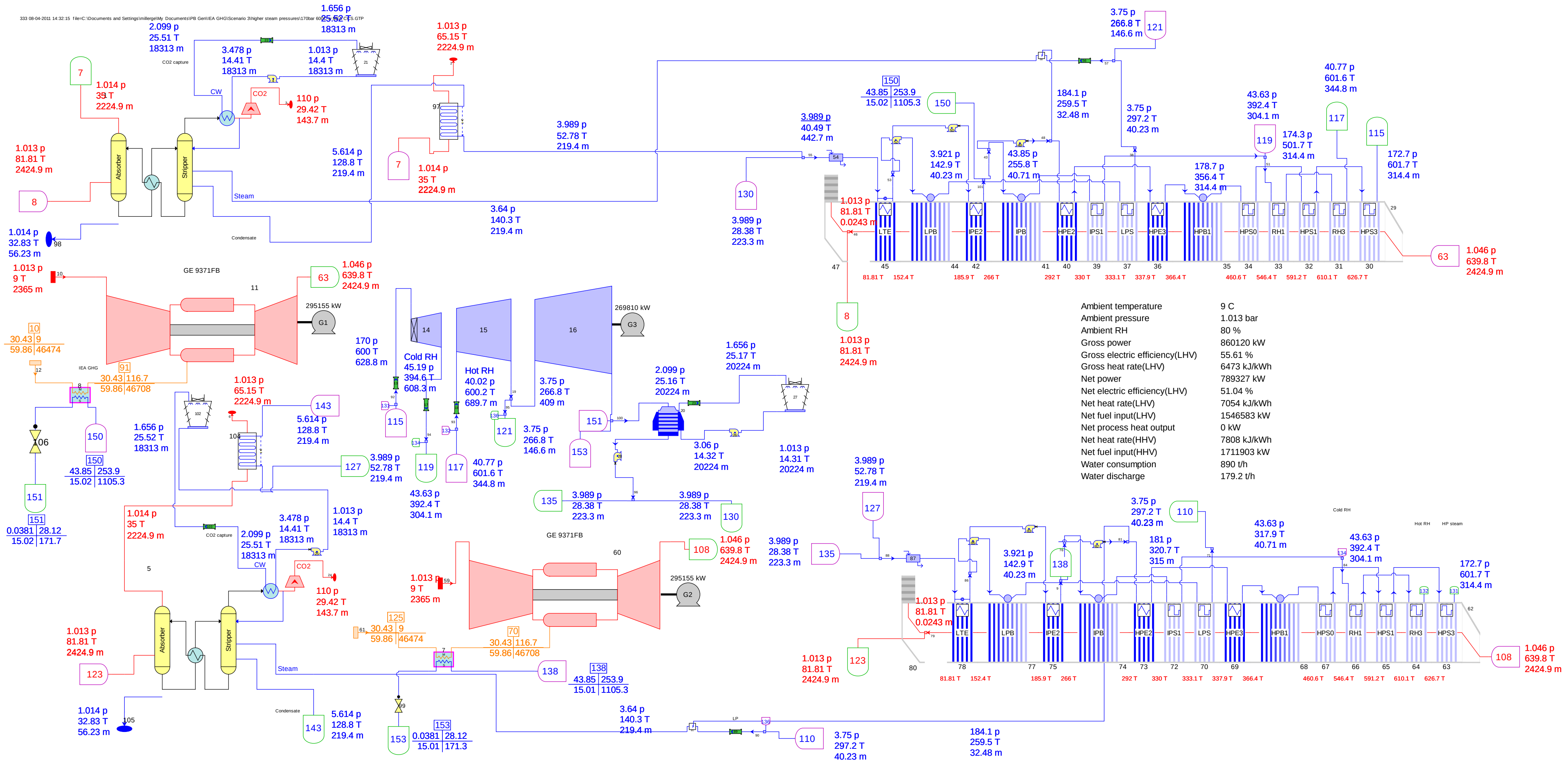
bar	C
t/h	kJ/kg



Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	934036 kW
Gross electric efficiency(LHV)	60.41 %
Gross heat rate(LHV)	5959 kJ/kWh
Net power	910293 kW
Net electric efficiency(LHV)	58.87 %
Net heat rate(LHV)	6115 kJ/kWh
Net fuel input(LHV)	1546181 kW
Plant auxiliary	23743 kW
Net electric efficiency(HHV)	53.19 %
Net heat rate(HHV)	6768 kJ/kWh
Net fuel input(HHV)	1711458 kW
Water consumption	596.4 t/h
Water discharge	120.4 t/h

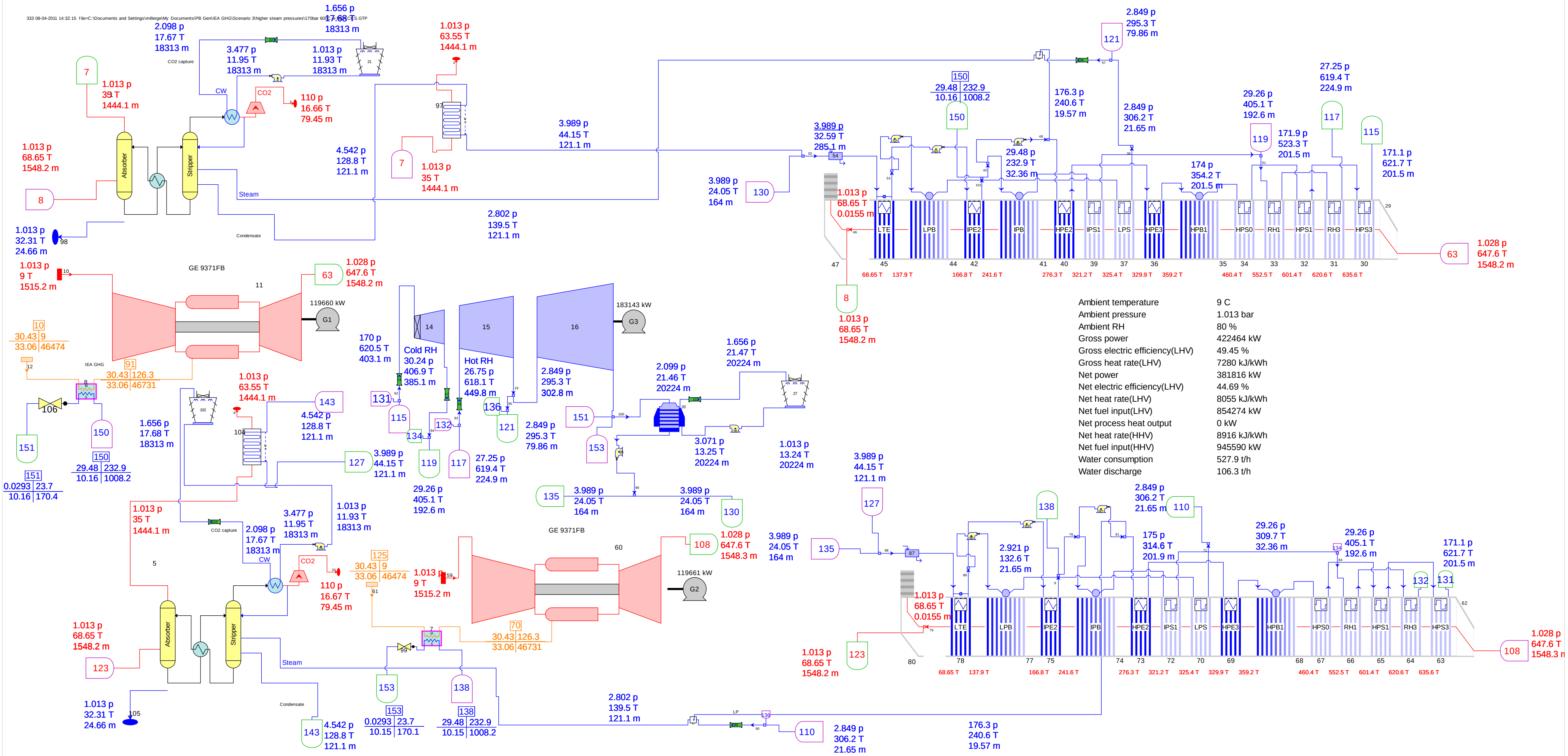


Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	463536 kW
Gross electric efficiency(LHV)	53.30 %
Gross heat rate(LHV)	6630 kJ/kWh
Net power	442900 kW
Net electric efficiency(LHV)	51.88 %
Net heat rate(LHV)	6939 kJ/kWh
Net fuel input(LHV)	853681 kW
Plant auxiliary	20636 kW
Net electric efficiency(HHV)	47.1 %
Net heat rate(HHV)	7643 kJ/kWh
Net fuel input(HHV)	944933 kW
Water consumption	388.2 t/h
Water discharge	78.29 t/h

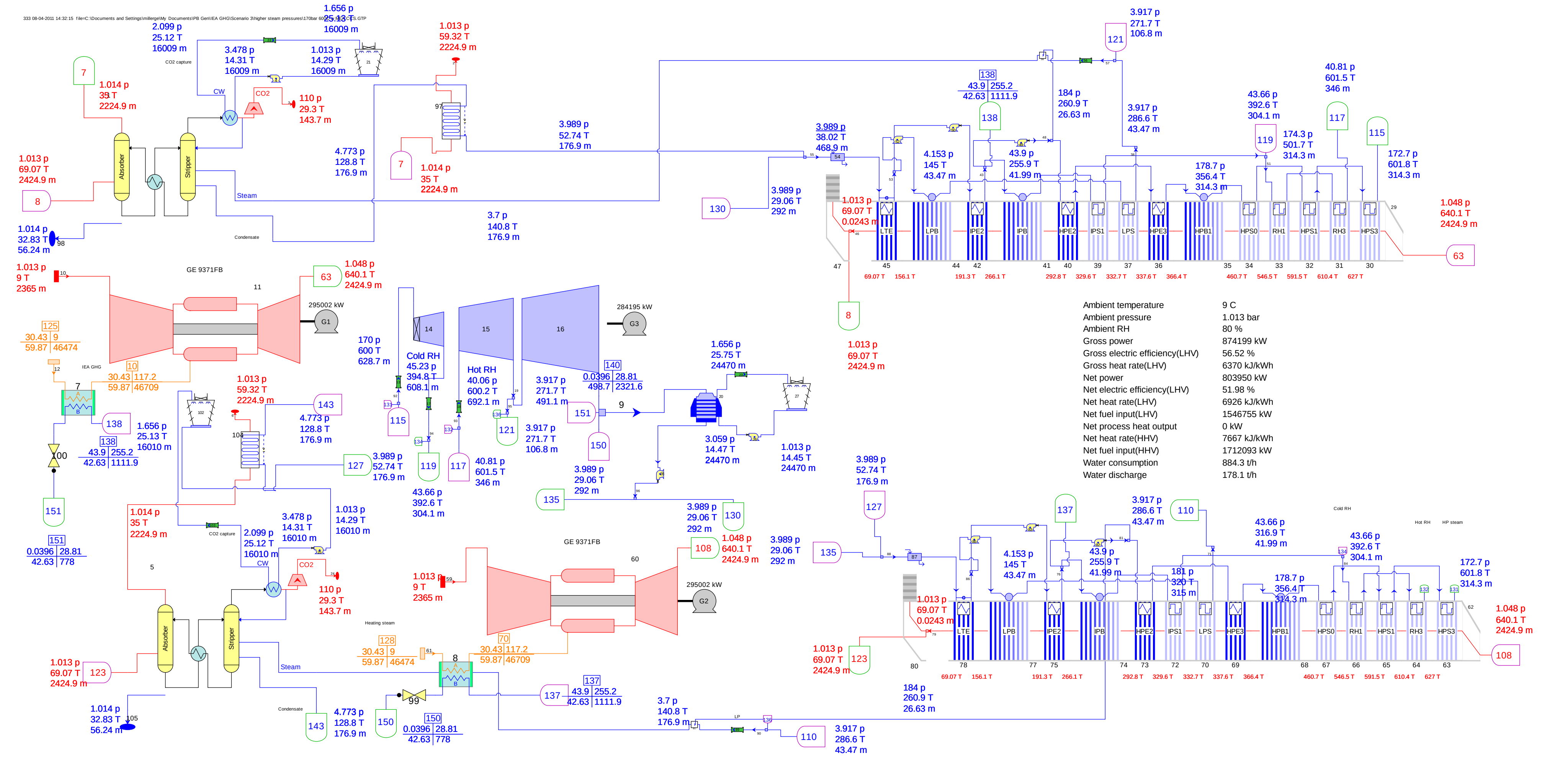


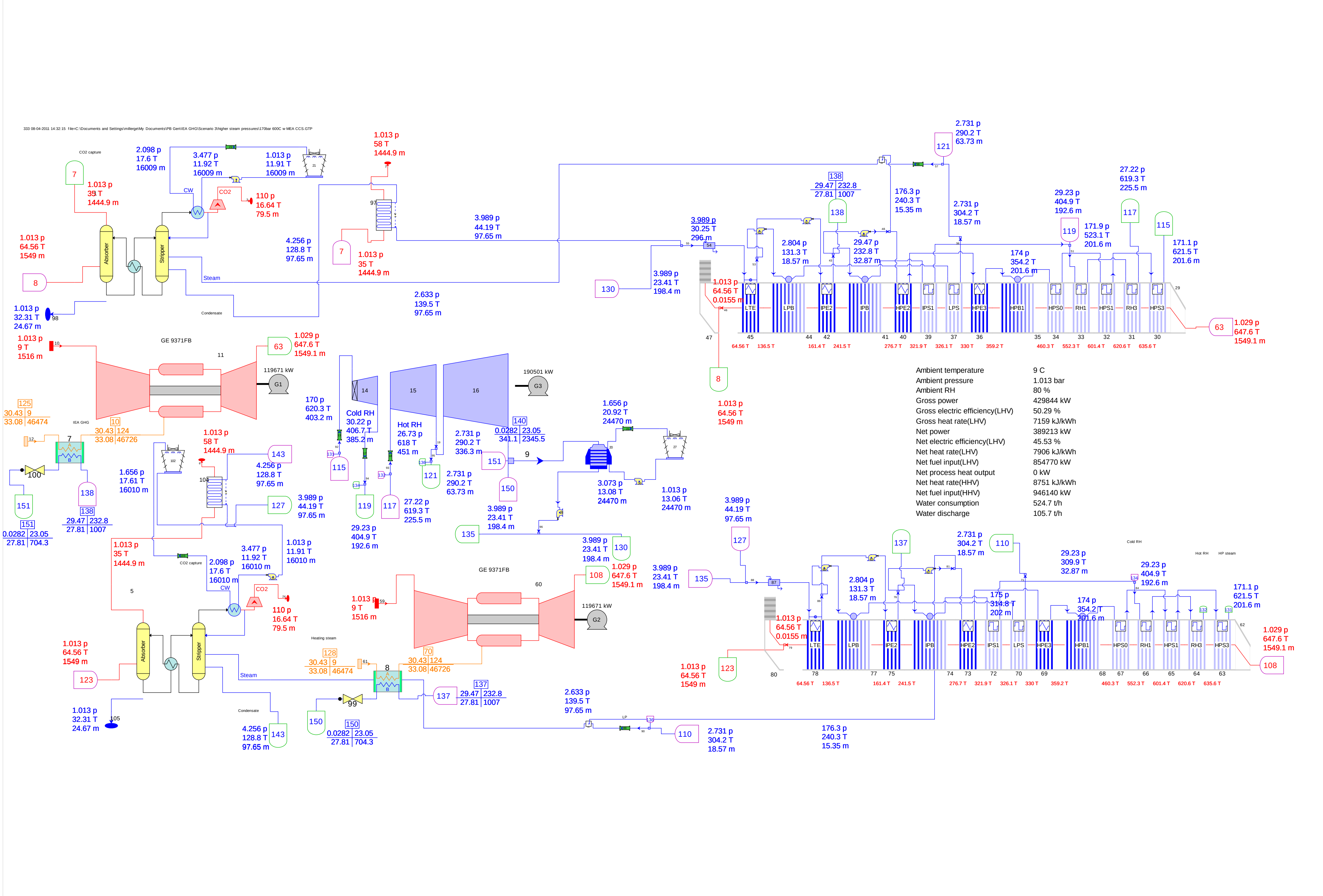
Ambient temperature	9 C
Ambient pressure	1.013 bar
Ambient RH	80 %
Gross power	860120 kW
Gross electric efficiency(LHV)	55.61 %
Gross heat rate(LHV)	6473 kJ/kWh
Net power	789327 kW
Net electric efficiency(LHV)	51.04 %
Net heat rate(LHV)	7054 kJ/kWh
Net fuel input(LHV)	1546583 kW
Net process heat output	0 kW
Net heat rate(HHV)	7808 kJ/kWh
Net fuel input(HHV)	1711903 kW
Water consumption	890 t/h
Water discharge	179.2 t/h

bar | C
t/h | kJ/kg

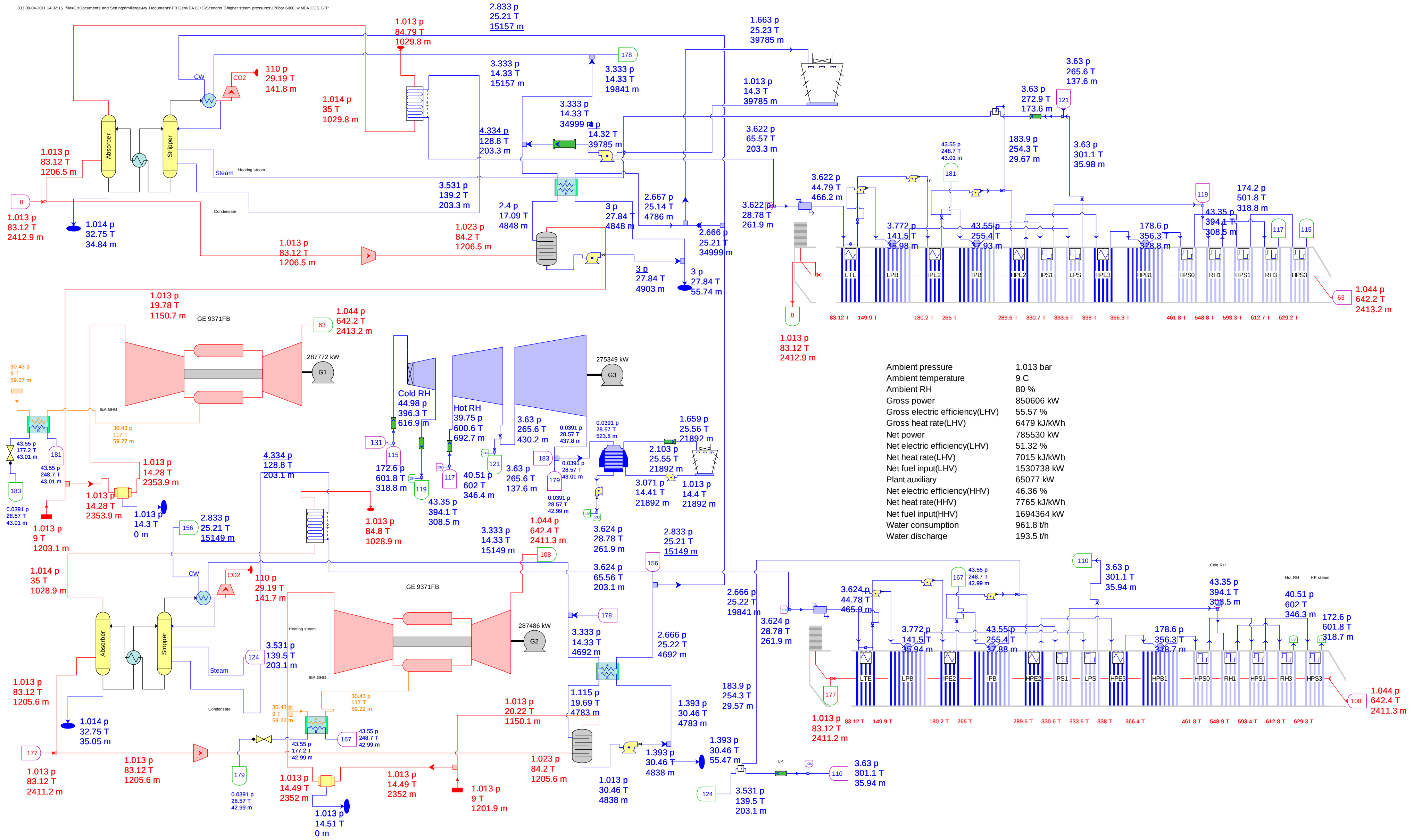


Ambient temperature	9 C
Ambient pressure	1.013 bar
Ambient RH	80 %
Gross power	422464 kW
Gross electric efficiency(LHV)	49.45 %
Gross heat rate(LHV)	7280 kJ/kWh
Net power	381816 kW
Net electric efficiency(LHV)	44.69 %
Net heat rate(LHV)	8055 kJ/kWh
Net fuel input(LHV)	854274 kW
Net process heat output	0 kW
Net heat rate(HHV)	8916 kJ/kWh
Net fuel input(HHV)	945590 kW
Water consumption	527.9 t/h
Water discharge	106.3 t/h

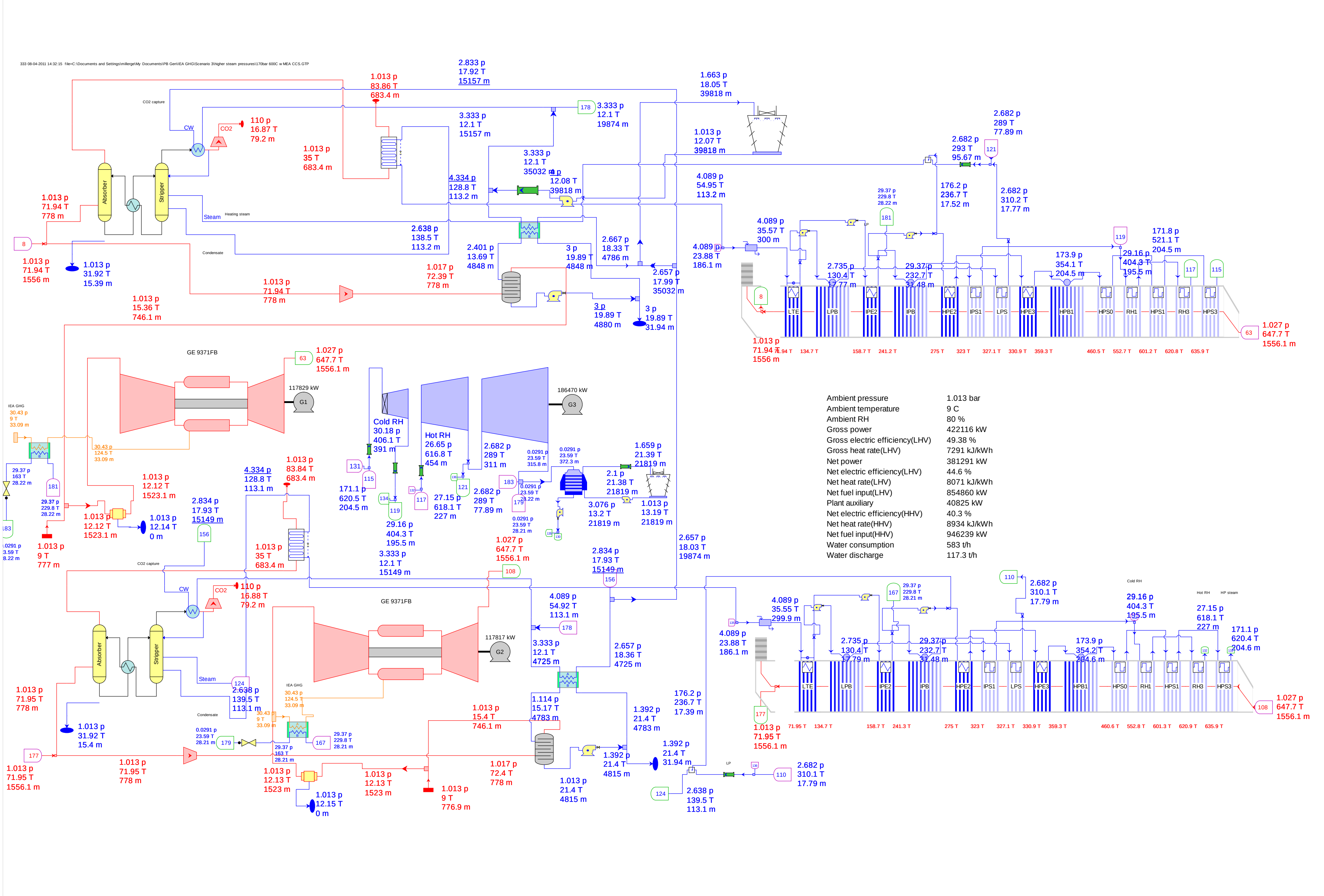

GE 9371FB
295002 kW
284195 kW
GE 9371FB
295002 kW
Absorber
Stripper
CO2 capture
Steam
Condensate
Cold RH
Hot RH
Heating steam
LTE
LPB
IPE2
IPB
HPE2
IPS1
LPS
HPE3
HPB1
HPS0
RH1
HPS1
RH3
HPS3
Ambient temperature 9 C
Ambient pressure 1.013 bar
Ambient RH 80 %
Gross power 874199 kW
Gross electric efficiency(LHV) 56.52 %
Gross heat rate(LHV) 6370 kJ/kWh
Net power 803950 kW
Net electric efficiency(LHV) 51.98 %
Net heat rate(LHV) 6926 kJ/kWh
Net fuel input(LHV) 1546755 kW
Net process heat output 0 kW
Net heat rate(HHV) 7667 kJ/kWh
Net fuel input(HHV) 1712093 kW
Water consumption 884.3 t/h
Water discharge 178.1 t/h


GE 9371FB
119671 kW
190501 kW
CO2 capture
Absorber
Stripper
Steam
Condensate
Heating steam
Cold RH
Hot RH
LTE
LPB
IPE2
IPB
HPE2
IPS1
LPS
HPE3
HPB1
HPS0
RH1
HPS1
RH3
HPS3
Ambient temperature 9 C
Ambient pressure 1.013 bar
Ambient RH 80 %
Gross power 429844 kW
Gross electric efficiency(LHV) 50.29 %
Gross heat rate(LHV) 7159 kJ/kWh
Net power 389213 kW
Net electric efficiency(LHV) 45.53 %
Net heat rate(LHV) 7906 kJ/kWh
Net fuel input(LHV) 854770 kW
Net process heat output 0 kW
Net heat rate(HHV) 8751 kJ/kWh
Net fuel input(HHV) 946140 kW
Water consumption 524.7 t/h
Water discharge 105.7 t/h

bar	C
t/h	kJ/kg



Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	850606 kW
Gross electric efficiency(LHV)	55.57 %
Gross heat rate(LHV)	6479 kJ/kWh
Net power	785530 kW
Net electric efficiency(LHV)	51.32 %
Net heat rate(LHV)	7015 kJ/kWh
Net fuel input(LHV)	1530738 kW
Plant auxiliary	65077 kW
Net electric efficiency(HHV)	46.36 %
Net heat rate(HHV)	7765 kJ/kWh
Net fuel input(HHV)	1694364 kW
Water consumption	961.8 t/h
Water discharge	193.5 t/h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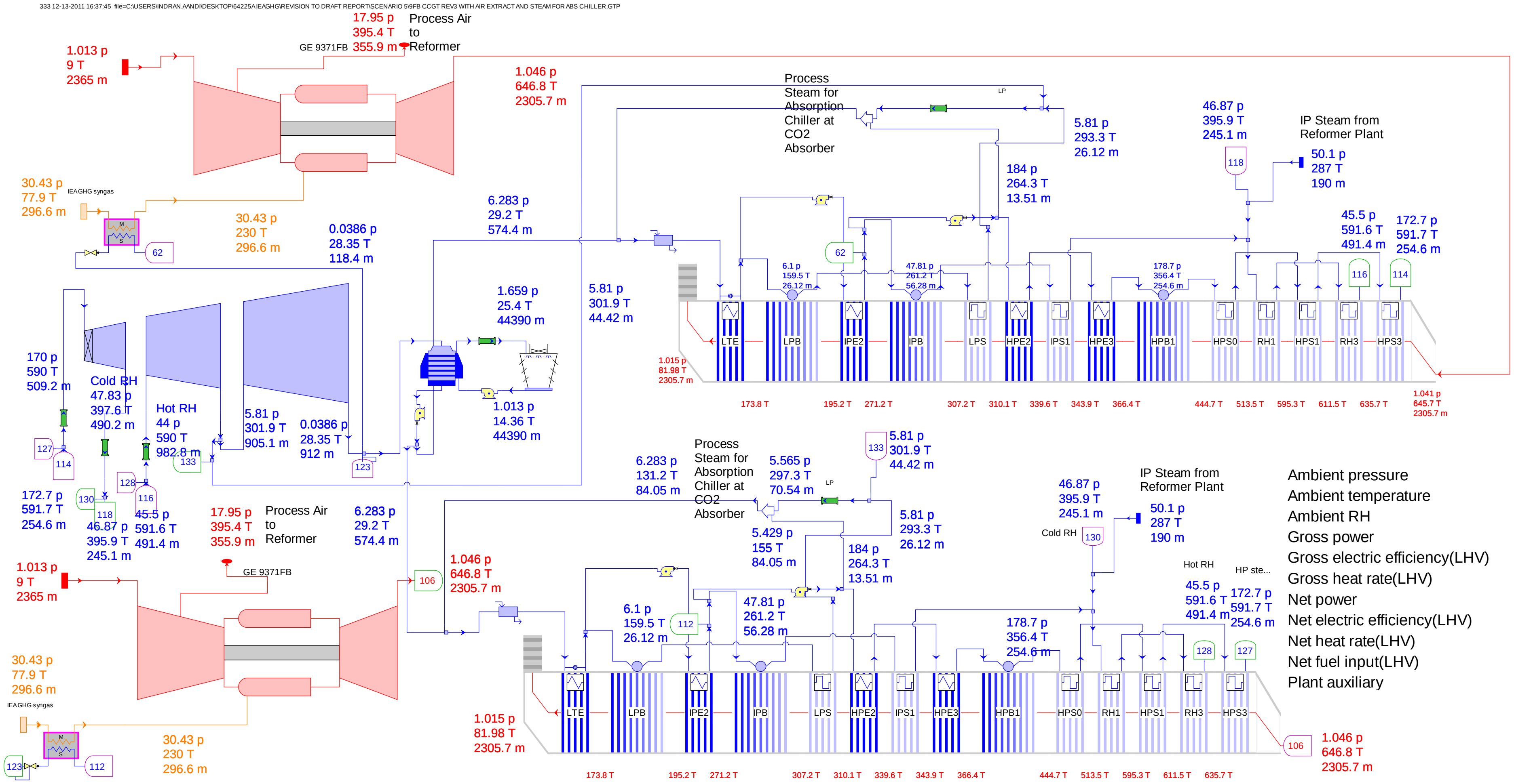
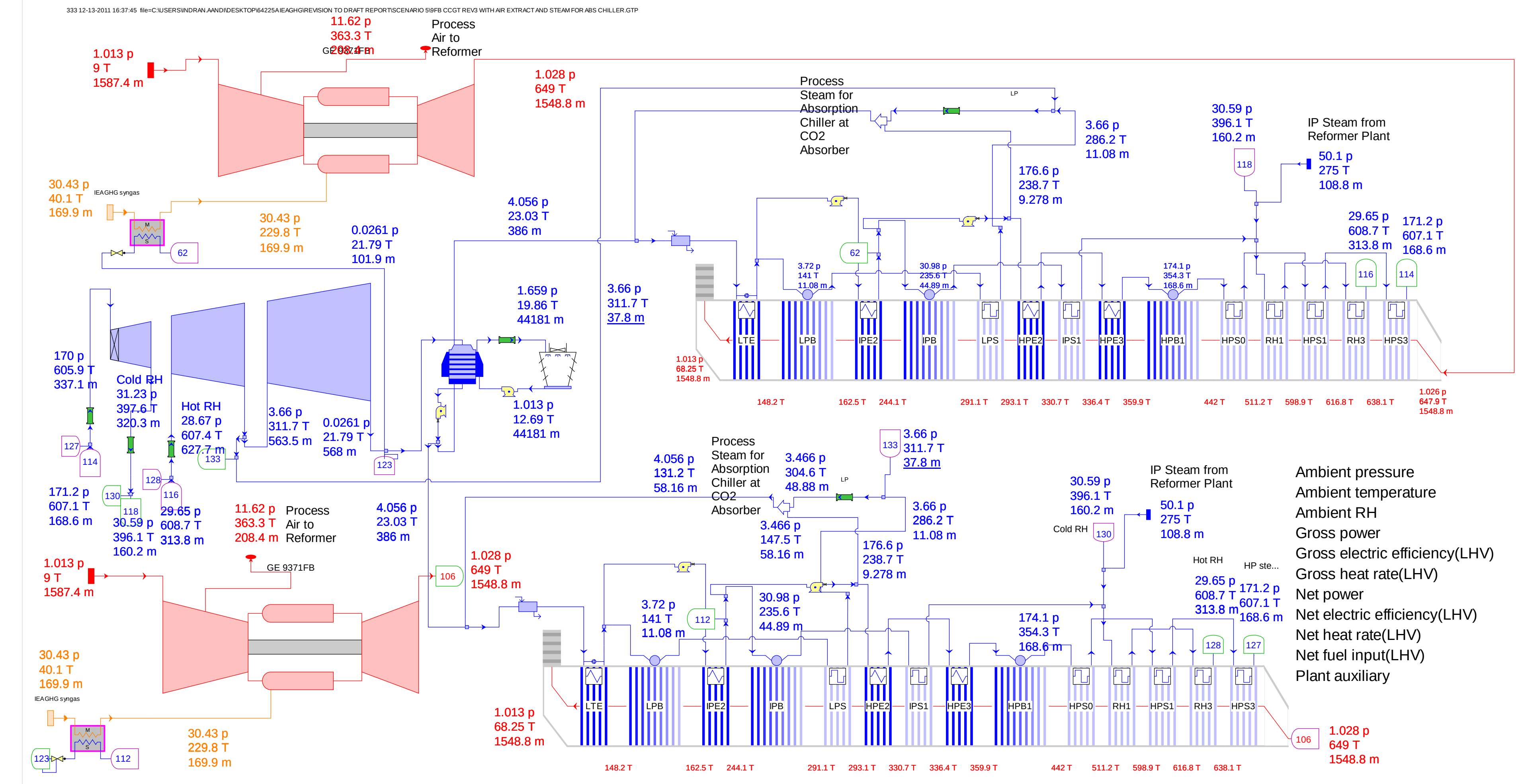
CO2 capture
Absorber
Stripper
Steam
Heating steam
Condensate
CW
CO2
GE 9371FB
117829 kW
G1
117817 kW
G2
186470 kW
G3
Cold RH
Hot RH
IEA GHG
LTE
LPB
IPE2
IPB
HPE2
IPS1
LPS
HPE3
HPB1
HPS0
RH1
HPS1
RH3
HPS3
Ambient pressure 1.013 bar
Ambient temperature 9 C
Ambient RH 80 %
Gross power 422116 kW
Gross electric efficiency(LHV) 49.38 %
Gross heat rate(LHV) 7291 kJ/kWh
Net power 381291 kW
Net electric efficiency(LHV) 44.6 %
Net heat rate(LHV) 8071 kJ/kWh
Net fuel input(LHV) 854860 kW
Plant auxiliary 40825 kW
Net electric efficiency(HHV) 40.3 %
Net heat rate(HHV) 8934 kJ/kWh
Net fuel input(HHV) 946239 kW
Water consumption 583 t/h
Water discharge 117.3 t/h

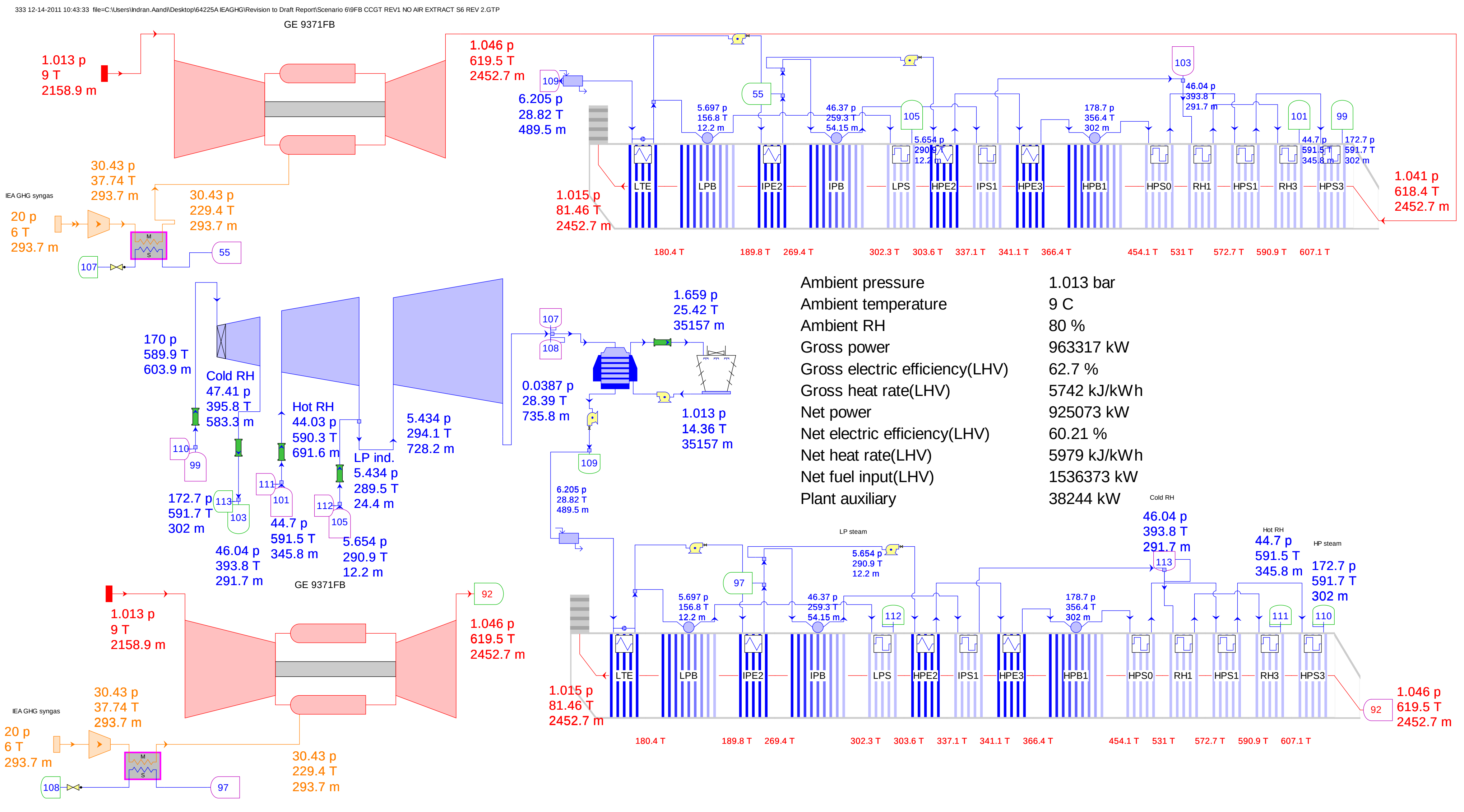


Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	985403 kW
Gross electric efficiency(LHV)	63.48 %
Gross heat rate(LHV)	5671 kJ/kWh
Net power	959432 kW
Net electric efficiency(LHV)	61.8 %
Net heat rate(LHV)	5825 kJ/kWh
Net fuel input(LHV)	1552384 kW
Plant auxiliary	25971 kW

bar	C
t/h	kJ/kg

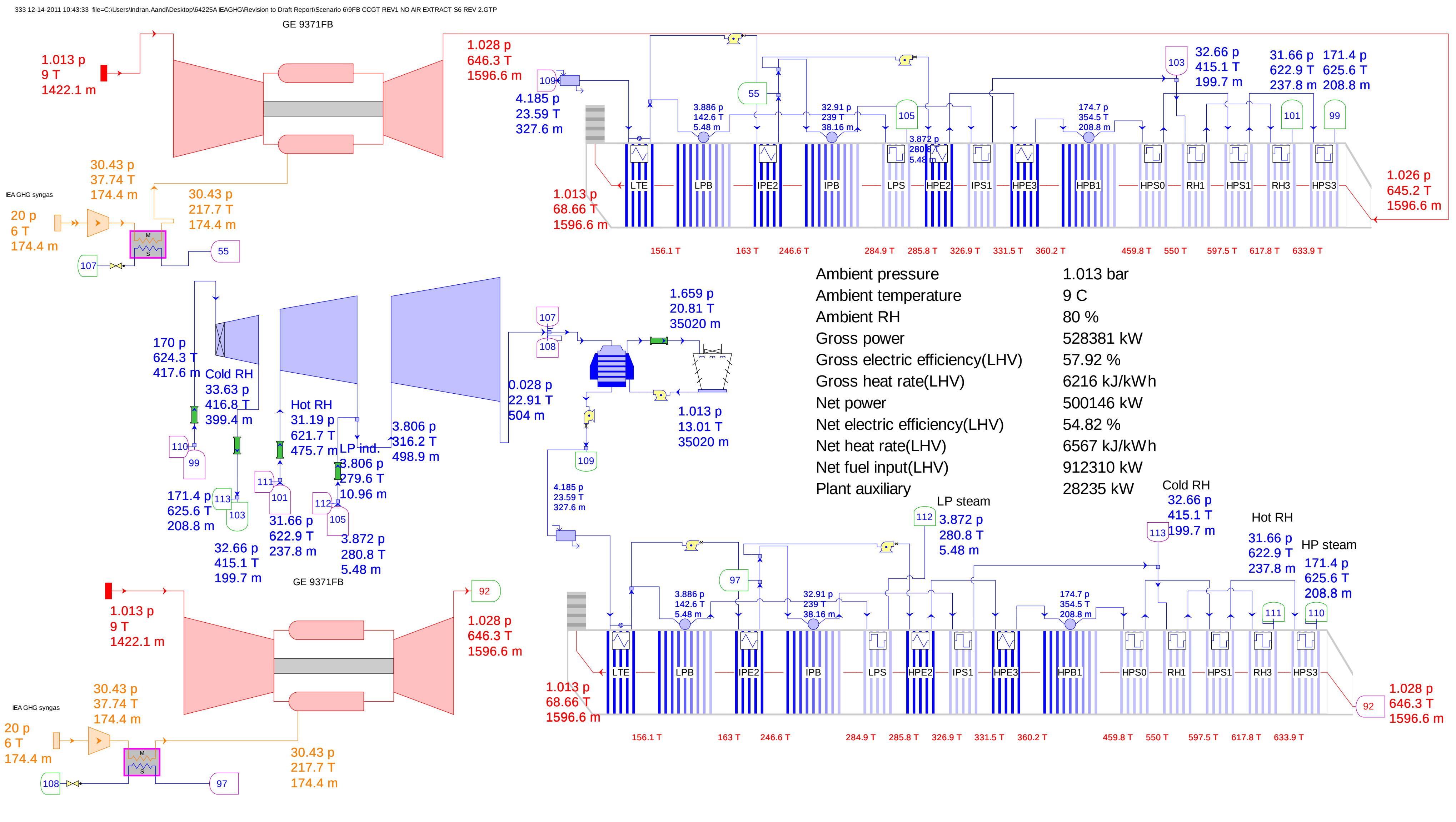


Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	520602 kW
Gross electric efficiency(LHV)	57.69 %
Gross heat rate(LHV)	6241 kJ/kWh
Net power	499575 kW
Net electric efficiency(LHV)	55.36 %
Net heat rate(LHV)	6503 kJ/kWh
Net fuel input(LHV)	902453 kW
Plant auxiliary	21027 kW



Ambient pressure	1.013 bar
Ambient temperature	9 C
Ambient RH	80 %
Gross power	963317 kW
Gross electric efficiency(LHV)	62.7 %
Gross heat rate(LHV)	5742 kJ/kWh
Net power	925073 kW
Net electric efficiency(LHV)	60.21 %
Net heat rate(LHV)	5979 kJ/kWh
Net fuel input(LHV)	1536373 kW
Plant auxiliary	38244 kW

bar | C
t/h | kJ/kg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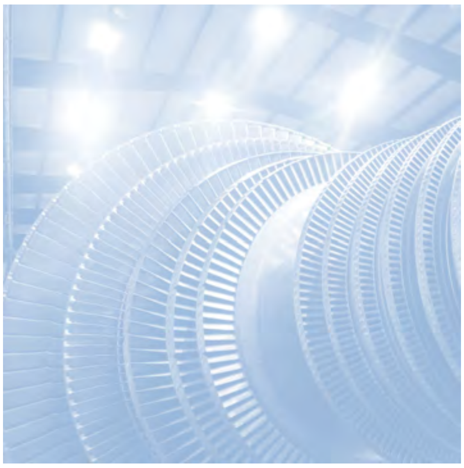
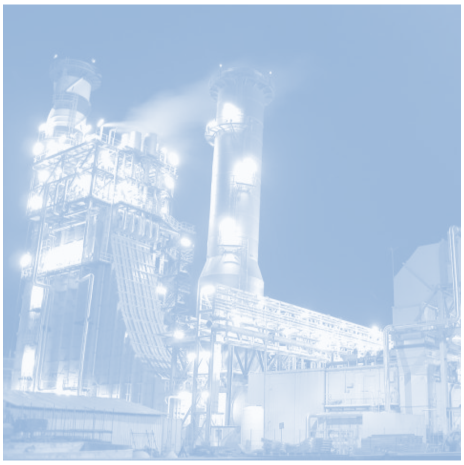
GE 9371FB
1.013 p
9 T
1422.1 m
1.028 p
646.3 T
1596.6 m
4.185 p
23.59 T
327.6 m
32.66 p
415.1 T
199.7 m
31.66 p
622.9 T
237.8 m
171.4 p
625.6 T
208.8 m
1.026 p
645.2 T
1596.6 m
1.013 p
68.66 T
1596.6 m
30.43 p
37.74 T
174.4 m
IEA GHG syngas
20 p
6 T
174.4 m
30.43 p
217.7 T
174.4 m
LTE
LPB
IPE2
IPB
LPS
HPE2
IPS1
HPE3
HPB1
HPS0
RH1
HPS1
RH3
HPS3
3.886 p
142.6 T
5.48 m
32.91 p
239 T
38.16 m
3.872 p
280.8 T
5.48 m
174.7 p
354.5 T
208.8 m
156.1 T
163 T
246.6 T
284.9 T
285.8 T
326.9 T
331.5 T
360.2 T
459.8 T
550 T
597.5 T
617.8 T
633.9 T
170 p
624.3 T
417.6 m
Cold RH
33.63 p
416.8 T
399.4 m
Hot RH
31.19 p
621.7 T
475.7 m
LP ind.
3.806 p
279.6 T
10.96 m
3.806 p
316.2 T
498.9 m
0.028 p
22.91 T
504 m
1.659 p
20.81 T
35020 m
1.013 p
13.01 T
35020 m
171.4 p
625.6 T
208.8 m
32.66 p
415.1 T
199.7 m
31.66 p
622.9 T
237.8 m
3.872 p
280.8 T
5.48 m
Ambient pressure 1.013 bar
Ambient temperature 9 C
Ambient RH 80 %
Gross power 528381 kW
Gross electric efficiency(LHV) 57.92 %
Gross heat rate(LHV) 6216 kJ/kWh
Net power 500146 kW
Net electric efficiency(LHV) 54.82 %
Net heat rate(LHV) 6567 kJ/kWh
Net fuel input(LHV) 912310 kW
Plant auxiliary 28235 kW
LP steam
3.872 p
280.8 T
5.48 m
Cold RH
32.66 p
415.1 T
199.7 m
Hot RH
31.66 p
622.9 T
237.8 m
HP steam
171.4 p
625.6 T
208.8 m
GE 9371FB
1.013 p
9 T
1422.1 m
1.028 p
646.3 T
1596.6 m
30.43 p
37.74 T
174.4 m
IEA GHG syngas
20 p
6 T
174.4 m
30.43 p
217.7 T
174.4 m
1.013 p
68.66 T
1596.6 m
1.028 p
646.3 T
1596.6 m

APPENDIX F





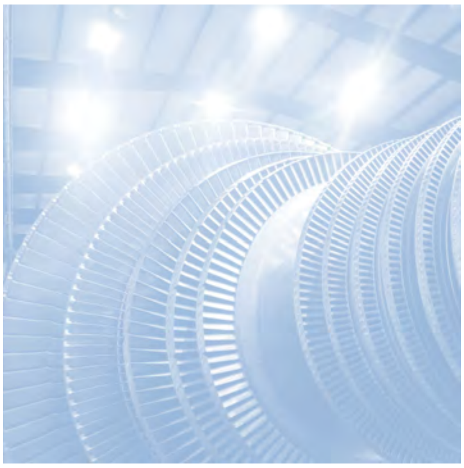
ECONOMIC MODELLING ASSUMPTIONS

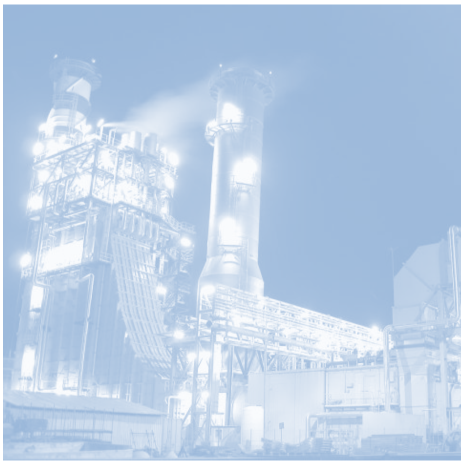
APPENDIX F: ECONOMIC BASE CASE MODELLING ASSUMPTIONS

	S1: CCGT	S3: CCGT with Post Combustion Capture	S3B: CCGT with Post Combustion Capture (Proprietary System)	S4: CCGT with Post Combustion Capture and Exhaust Gas Recirculation	S5: CCGT with Natural Gas Reforming and Pre Combustion Capture	S6: Natural Gas Reforming and Pre Combustion Capture, and Remote CCGT
General						
Primary Fuel Used	Gas	Gas	Gas	Gas	Gas	Gas
Net Power Output (MW)	910.3	789.3	804.0	785.5	849.9	736.8
First Year Capacity Factor (%)	90.0%	60.0%	60.0%	60.0%	60.0%	60.0%
Capacity Factor (%)	93.0%	90.0%	90.0%	90.0%	85.0%	85.0%
Plant Efficiency @ LHV (%)	58.9%	51.0%	52.0%	51.3%	42.3%	36.8%
Heat Rate @ LHV (kJ / kWh)	6,115	7,053	6,926	7,015	8,510	9,795
Economic Life Expectancy (Years)	25	25	25	25	25	25
CO2 Emitted (kg / MWh)	348.3	41.0	39.9	40.7	89.4	103.6
CO2 Stored (kg / MWh)	0.0	365.0	359.2	362.1	395.3	454.4
Capital Expenditure						
Financial Disbursement Period (Years)	4	4	4	4	4	4
Specific EPC Capital Cost (EUR / kW)	637.1	1,400.7	1,164.5	1,285.3	1,595.2	2,420.6
Capital Disbursements (% of total)	ok	ok	ok	ok	ok	ok
First Year of Commercial Operation (O)	0%	0%	0%	0%	0%	0%
Final Year of Construction (C)	10%	10%	10%	10%	10%	10%
C – 1	40%	40%	40%	40%	40%	40%
C – 2	35%	35%	35%	35%	35%	35%
C – 3	15%	15%	15%	15%	15%	15%
C – 4	0%	0%	0%	0%	0%	0%
C – 5	0%	0%	0%	0%	0%	0%
Owners, Working and Start Up Costs	0	0	0	0	0	0
Owners Costs (% of EPC cost)	9%	9%	9%	9%	10%	10%
Consumables Storage (Days)	30	30	30	30	30	30
Start Up - Labour (Months)	3	3	3	3	4	4
Start Up - Maintenance (Months)	1	1	1	1	1	1
Start Up - Consumables (Months)	1	1	1	1	1	1
Start Up - Fuel (Months)	1	1	1	1	1	1
Start Up - Plant Modifications (% of TPC)	0	0	0	0	0	0
Operation and Maintenance Costs						
VOM or LTSA (cost per fired-hour (EUR))	660	1,132	959	1,034	1,389	1,827
Routine Maintenance Costs (EUR '000 p.a.)	9,500	16,300	13,803	14,885	19,989	26,295
Other Consumables (EUR¢ / MWh)	2.2	181.5	136.7	180.5	144.7	219.5
Overhead costs						
Number of Permanent staff	50	79	79	79	101	107
Average Salary (EUR '000)	60	60	60	60	60	60
Total Salary Costs (EUR '000)	3,000	4,740	4,740	4,740	6,060	6,420
Specific General & Admin Cost (EUR / kW)	3.14	4.36	4.36	4.36	4.36	4.36
Total General & Admin Cost (EUR '000 p.a.)	2,858	3,441	3,505	3,425	3,706	3,212

APPENDIX

G





ECONOMIC MODELLING SENSITIVITY ANALYSIS RESULTS

APPENDIX G: ECONOMIC MODELLING SENSITIVITIY ANALYSIS RESULTS

Sensitivity Results by Scenario

The lifetime cost of generation has been determined for each of the scenarios, under a number of technically and commercially feasible options. Figure G1 to Figure G6 present the results of this analysis on a scenario by scenario basis.

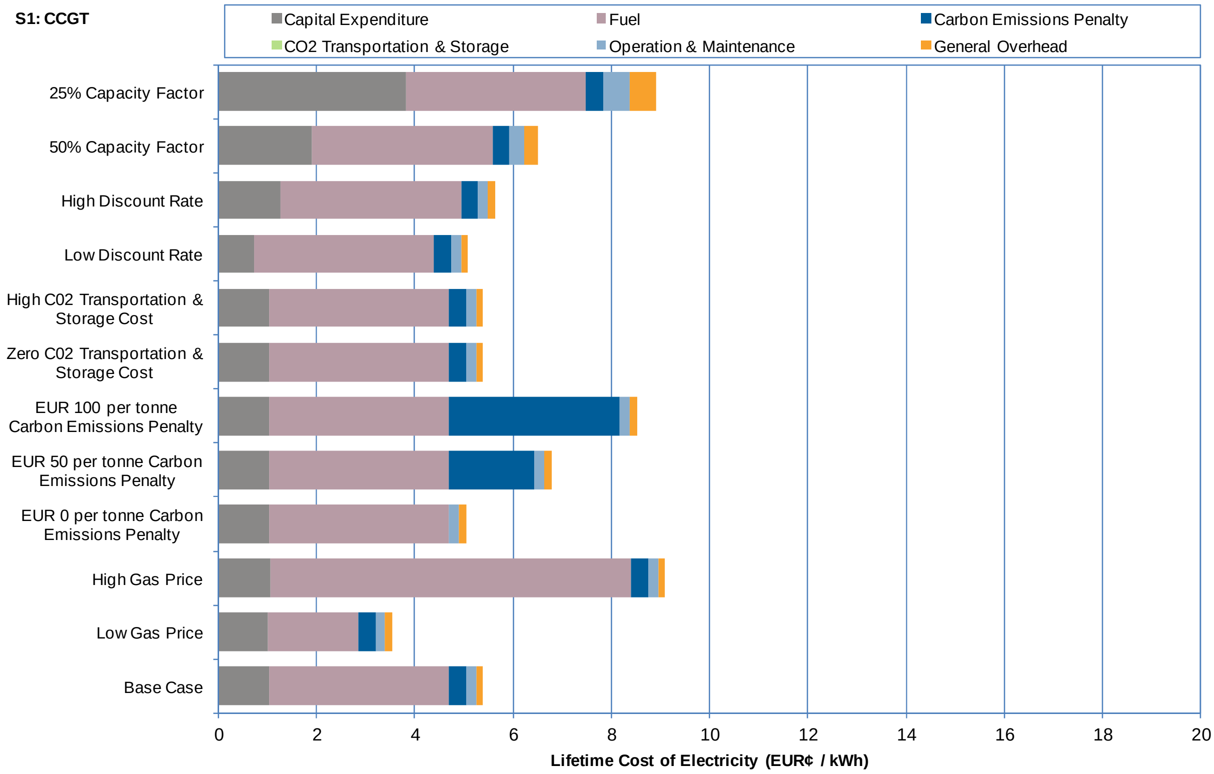


Figure G1 Lifetime Cost of Electricity (EUR¢ per kWh) – Scenario 1

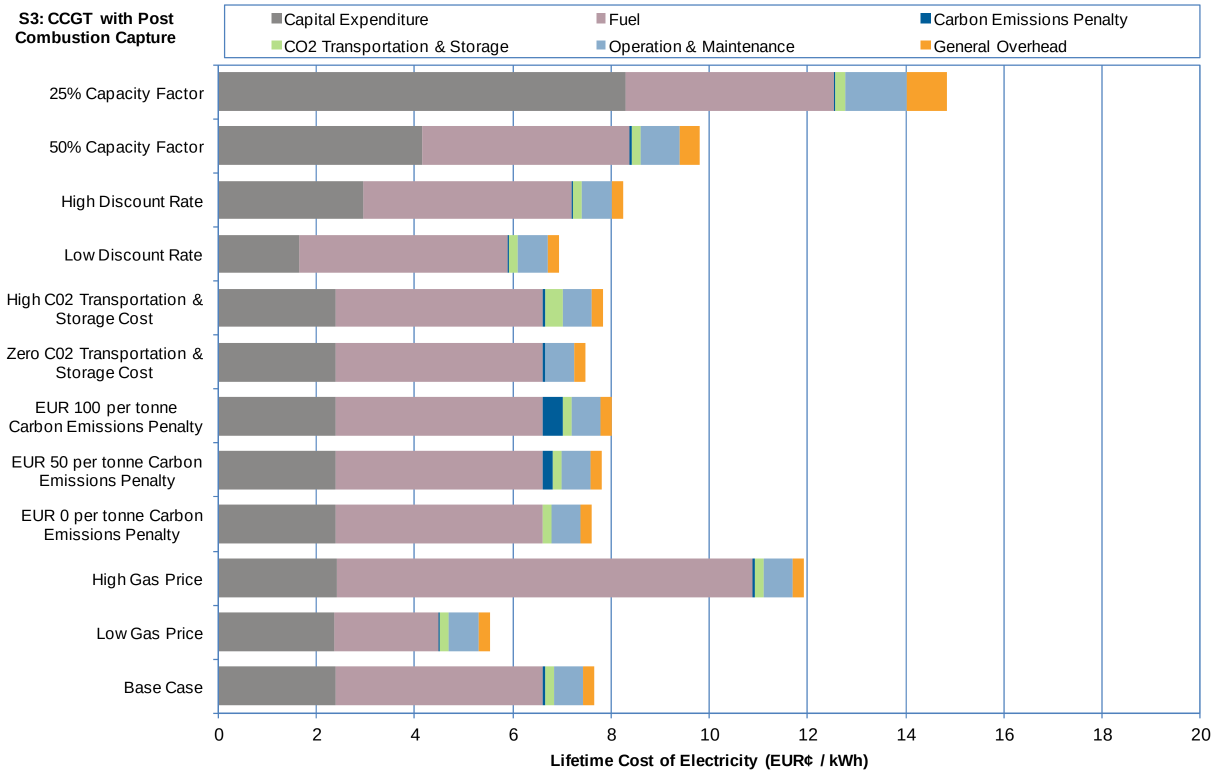


Figure G2 Lifetime Cost of Electricity (EUR¢ per kWh) – Scenario 3

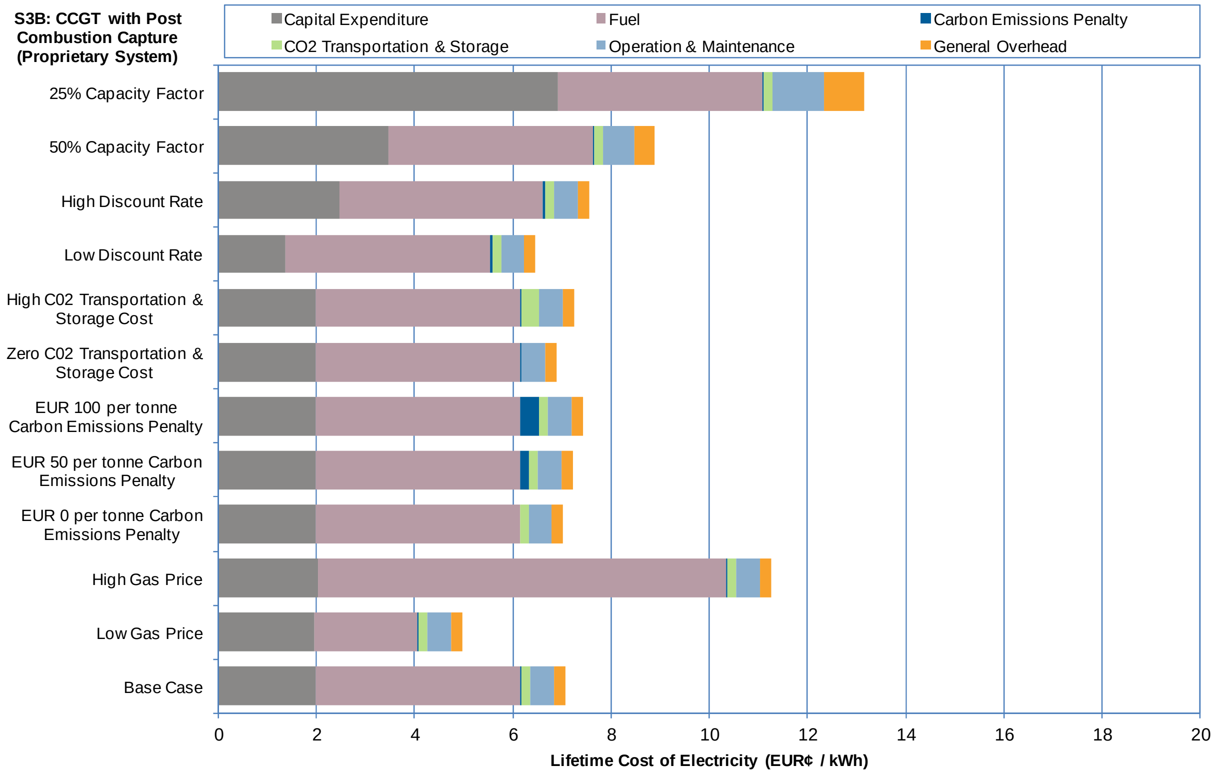


Figure G3 Lifetime Cost of Electricity (EUR¢ per kWh) – Scenario 3B

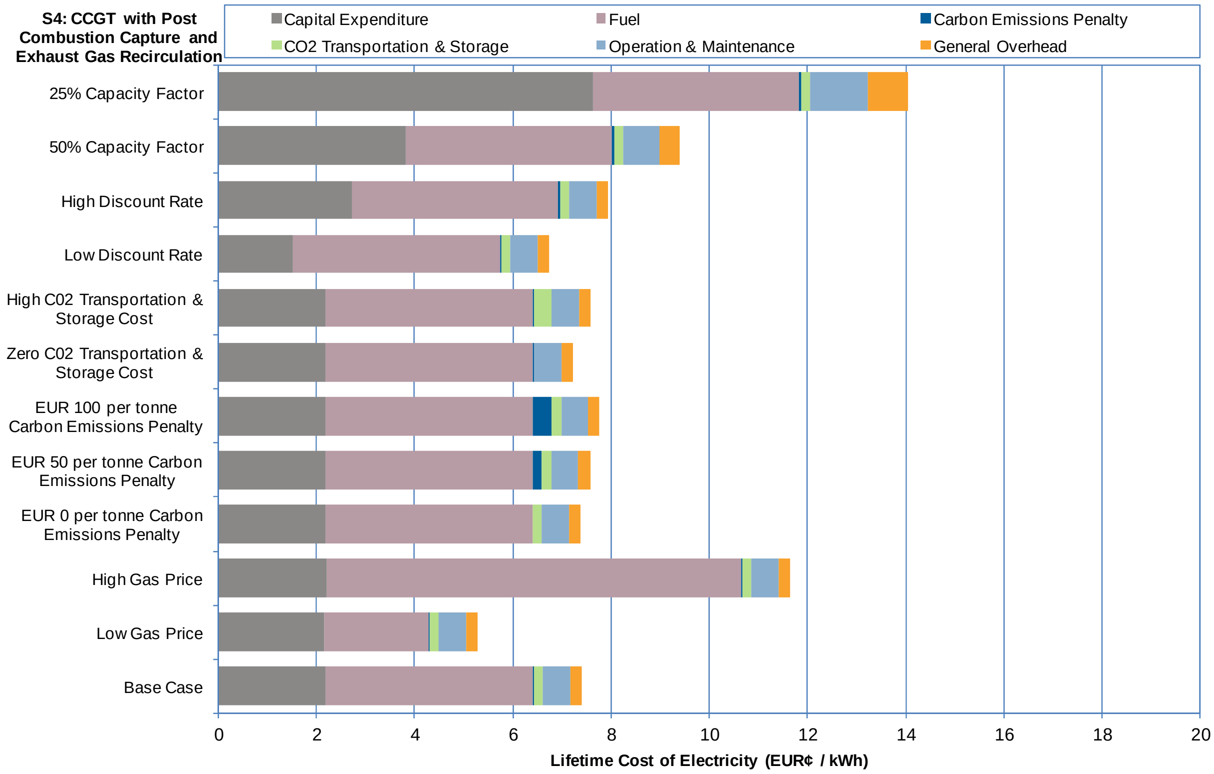


Figure G4 Lifetime Cost of Electricity (EUR¢ per kWh) – Scenario 4

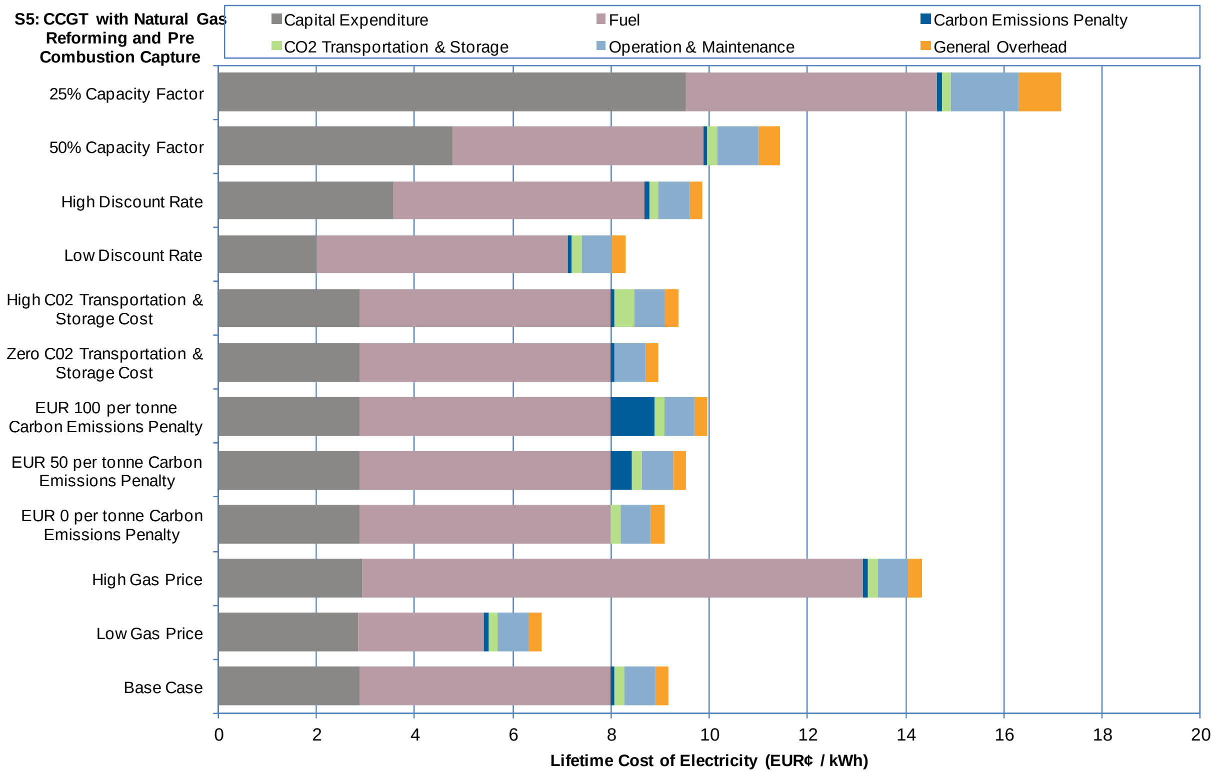


Figure G5 Lifetime Cost of Electricity (EUR¢ per kWh) – Scenario 5

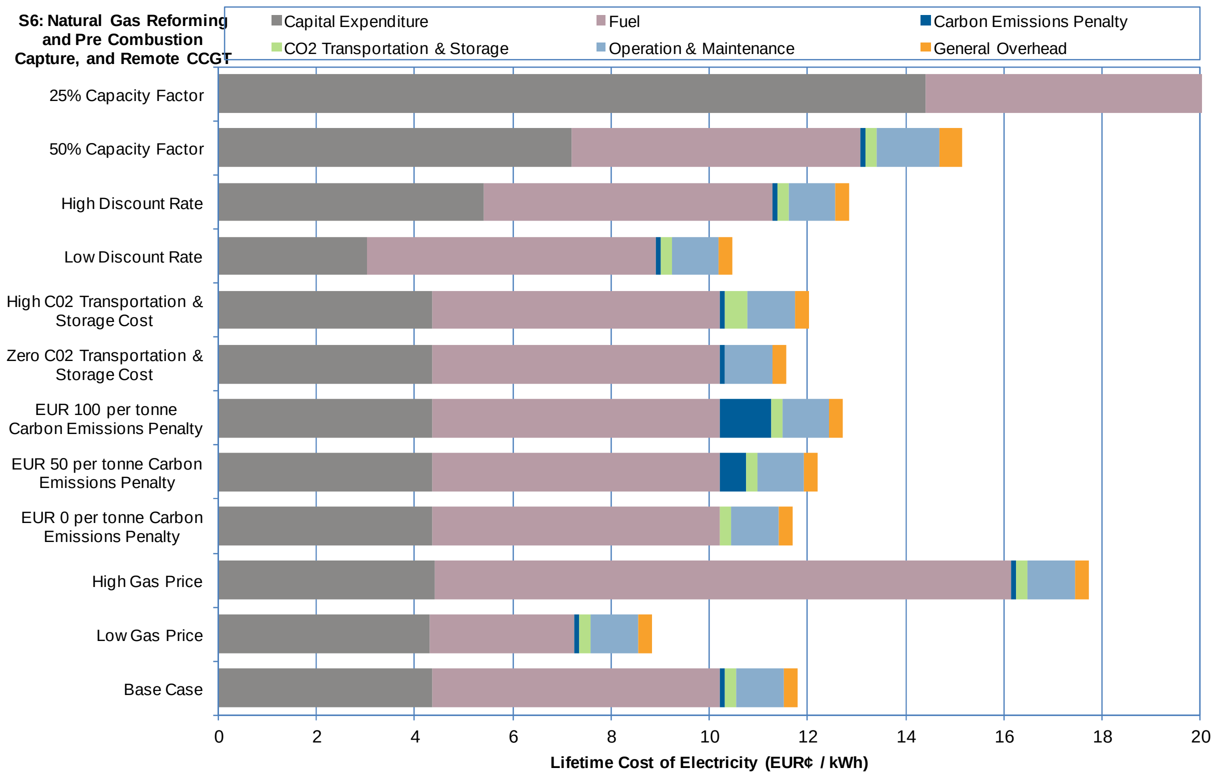
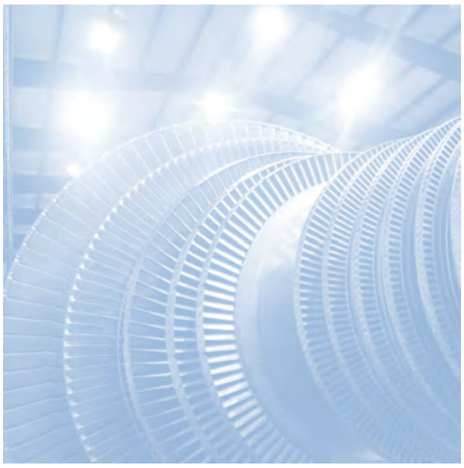
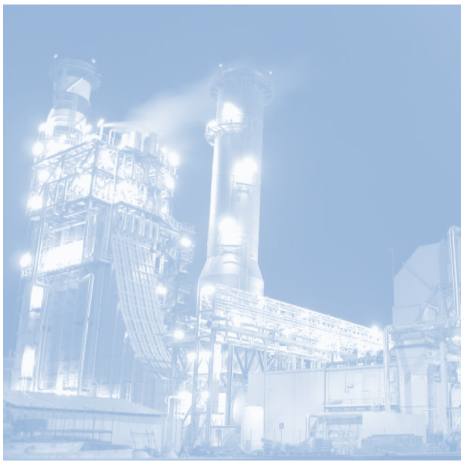


Figure G6 Lifetime Cost of Electricity (EUR¢ per kWh) – Scenario 6

APPENDIX

H




SIEMENS POST-COMBUSTION CAPTURE PROCESS

APPENDIX H: SIEMENS POST-COMBUSTION CAPTURE PROCESS

Siemens developed a second generation post-combustion CO_2 capture process which was optimized for integration in combined cycle power plants as well as conventional coal-fired power plants. It is referred to as the Siemens PostCap™ process.

Siemens had started 5 years ago with the development of the new post-combustion technology based on amino acid salt formulations. When having made the selection of the solvent, the following predominant criteria were established: the solvent and the process should be easy to handle, should not create additional emissions and should fall within existing power plant safety standards. Needless to say, that the capture efficiency, the energy demand and the solvent refill requirements should fully surpass the current standards.

Important to note is the fact that due to the ionic character of the amino acid salt solutions, the solvent exhibits a very good resistance against oxygen degradation (there is a higher content of oxygen in the flue gas of NG-CCPP than in the one for Coal fired stations).

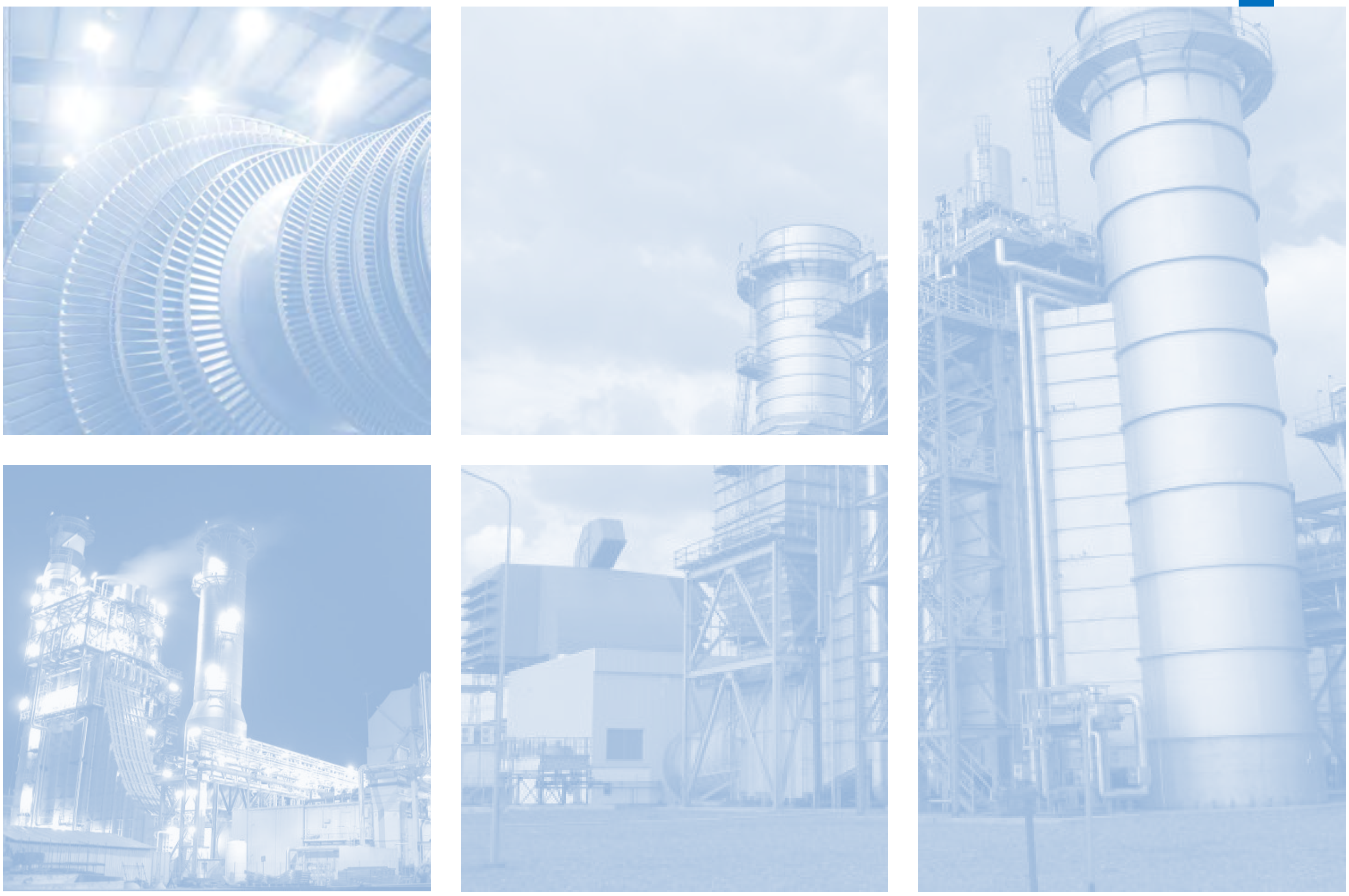
These characteristics have clearly been verified in thousands of hours laboratory scale testing and pilot plant testing

Emission measurements at the pilot plant in the Staudinger coal-fired power plant confirmed that there are neither detectable solvent emissions nor nitrosamine salt emissions at the top of the absorber. Thus additional washing steps for the absorber off-gas are not required. Main degradation products from side reactions with the flue gas trace components remain in the liquid phase and can be accumulated and removed via the re-claimer. The two step reclaiming has a much higher selectivity than the re-boiling systems of the amine based technologies. Further, the sulphur components will be separated and transformed into an industrial product.

The requirements for handling, transport and storage of the solvent are determined by its physical and chemical properties: it is neither inflammable, nor explosive and odourless and does not pose an inhalation risk. Since the components of the solvent are naturally occurring substances, the risks to human health, fauna and flora are very low.

The PostCap™ process is now ready for the implementation in large-scale units. For its implementation there are strong capabilities in chemical process engineering available at Siemens as well as all other disciplines required for building large-scale power stations.

APPENDIX



MHI POST-COMBUSTION CAPTURE PROCESS

MHI Commercial and Demo CO_2 Capture Plants

- World leading LARGE-SCALE post combustion CO_2 capture technology licensor, with 9 commercial PCC plants in operation (from a variety of **Natural Gas** sources)
- Largest operational post combustion CO_2 capture plant in the world (**Black Coal**)

1999

200 t/d Malaysia

2005

330 t/d Japan

2006

450 t/d India

2006

450 t/d India

2009

450 t/d India

2009

400 t/d UAE

2009

450 t/d Bahrain

2010

240 t/d Vietnam

2011

340 t/d Pakistan

2011

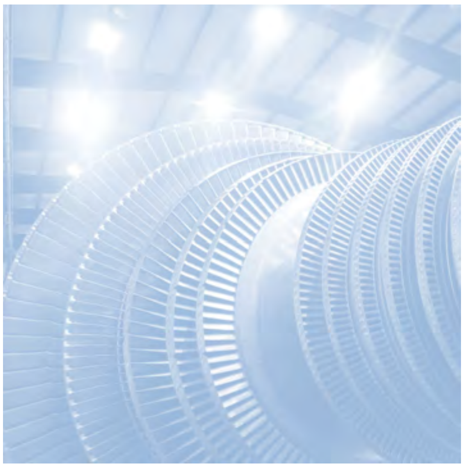
500 t/d USA

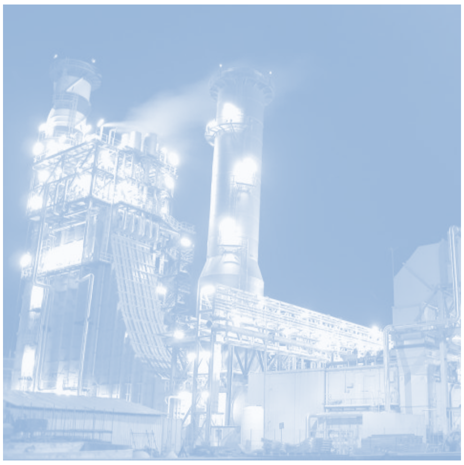
Q2 - 2012

450 t/d India

APPENDIX

J




REFERENCE LIST

APPENDIX J: REFERENCE LIST

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