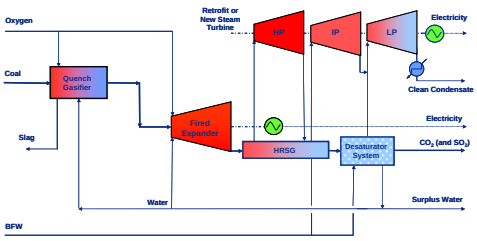
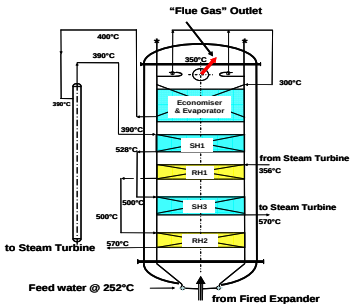
JACOBS
CONSULTANCY

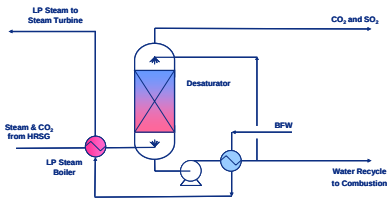
INDUSTRIAL AND UTILITY SCALE IGSC COAL POWER STATIONS

IGSC-Integrated Gasification Steam Cycle

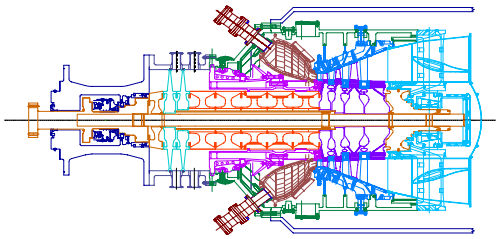


IGSC FLOWSCHEME





DESATURATOR SYSTEM



SGT5-4000F Oxy-Fuel Conversion

FINAL REPORT

OCTOBER 2008

By

Mohan Karmarkar/John Griffiths
Jacobs Consultancy

Andrew Russell
Siemens

Roger Allen
MAN

Mike Austell
CO_2 Global

Martin Trusler
Imperial College

The work described in this report was carried out under contract as part of the DTI Carbon Abatement Technology Programme with part funding. The Programme is managed by AEA Energy & Environment. The views and judgements expressed in this report are those of the contractor and do not necessarily reflect those of the DTI or AEA Energy & Environment.

First published 2008

EXECUTIVE SUMMARY

Introduction, Scope and Objectives

This document describes the structured development of a novel form of electricity generation from coal as a precursor to a new generation of Power Stations which intrinsically capture all their by-product carbon dioxide for secure storage.

Such processes for power generation do not exist at present and current concepts for recovering the CO_2 produced in fossil fuel power stations i.e. CCS technology, are effectively add-ons rather than an integral part of the basic design. As additions to a design optimised to produce power they would also reduce electricity output.

This new generating technology when applied as a retrofit to an existing power station will result in a higher net output and capture of 100% of by-product CO_2.

The work was carried out under partial government funding for a consortium consisting of Jacobs Consultancy as the lead partner, together with Siemens, Man Turbo, CO_2 Global and Imperial College. Designs are developed for a large-scale new plant, but more particularly for a retrofit and for a demonstration/industrial scale plant. The designs are completed to the stage where pre-feasibility studies could be carried out for specific applications. Some parallel research and development work is also recommended.

The final confirmation of the technology before commercialisation would be accomplished through the operation of the demonstration/industrial scale plant, which is beyond the scope of this project.

Design Basis

The Project was instigated as a result of a newly developed gas oxyburner (a burner using high purity oxygen rather than air) being introduced to Jacobs with the suggestion that it might be used for coal based CCS schemes in Europe. This burner was developed by Clean Energy Systems, Inc and is used on a semi-commercial basis in California, with natural gas fuel.

For application in Europe, the fuel gas will be produced from the gasification of coal. In order to reduce development time and to bring the new concept to market quickly, as much already commercially proven technology and equipment as possible is used.

The chosen location is the Humberside and South Yorkshire area of the UK, and the plants are designed to use a typical UK coal with the by-product CO_2 being transported to the North Sea for long-term storage.

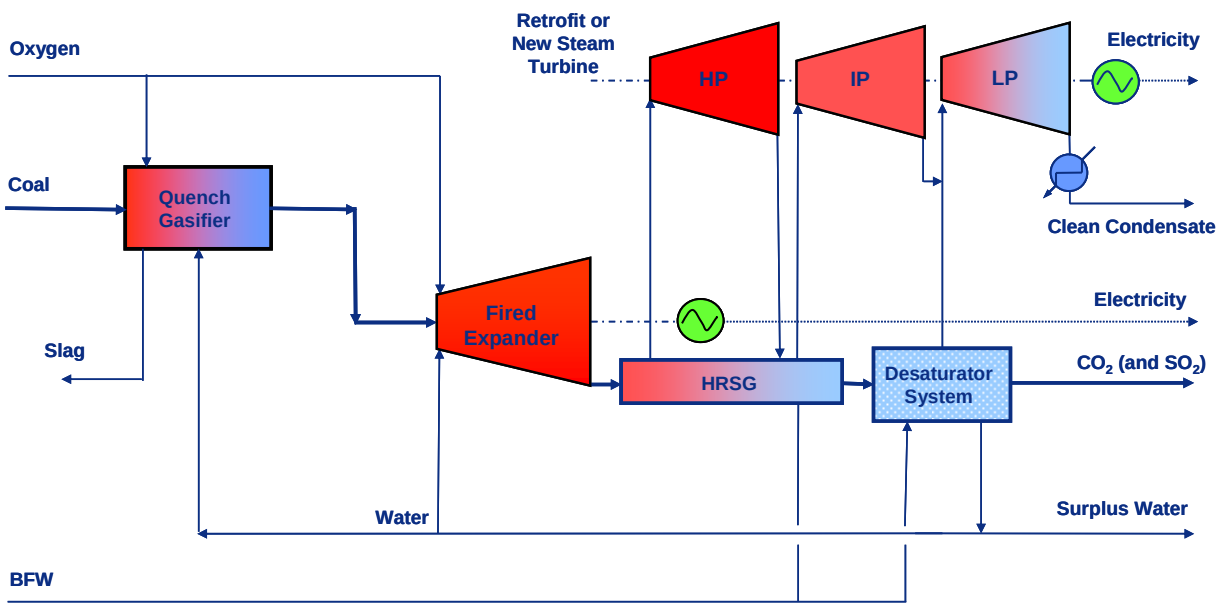
Plant and Process Description

The developed resultant process is named Integrated Gasification Steam Cycle (IGSC) and consists of two stage complete combustion of pulverised coal at high pressure, followed by expansion of the combustion gases to generate power.

The exhaust heat is used to raise high-pressure steam for use in a conventional condensing steam turbine.

Thus the plant is a combined-cycle of a hot expander followed by a steam turbine driven by steam raised from the hot expander exhaust.

The combustion gases which consist of steam mixed with by-product CO_2 are directly quenched with circulating cold water to condense all the steam leaving the CO_2 to be collected and compressed.



IGSC FLOWSCHEME

Risks

With the exception of two key items of equipment, the fired expander and HRSG, none of the equipment exhibits any new or excessive risk. The potential suppliers of these two items are confident that the design resides entirely within their experience and that nothing will exceed already experienced and well-known operating conditions.

Nevertheless these risks have not yet been experienced in combination in the same plant at the scale of a utility plant. It is therefore recommended that a programme of research and development be instigated. Before any commitment is made to commence design of a full scale plant, a pilot demonstration plant should be built and operated within which many of these risks can be examined in combination.

It iss also recommended that a research and development be instigated for examination and gathering of data regarding the process conditions and reactions.

Intellectual Property Rights (IPR)

More than seven discreet innovations were developed during the course of the work and a number have gone on to become the subject of patent applications.

The Consortium Collaboration Agreement makes it clear that any IPR brought by a Member to the Project work or invented by a Member during the course of that work belongs to that Member and shall not be unduly withheld for exploitation in a commercial project by any other Member.

For application of the technology outside of the UK, prior reference will be made to BERR.

Performance and Commercial Data

	Units	ASU		Note
		Included	Excluded	
Fixed				
Investment Cost	$/kW installed	4,235	1,801	2,3
Efficiency	% net LCV	27.9	40.7	4
Variable				
Coal Price	$/te	180	180	5
Oxygen Price	£/te	-	43.74	6
CO_2 Credit	€/te	25	25	5
Electricity Sale	£/MWh/h	90	90	5
Availability	%	92	92	7
Net Output	MWh/h	811	1088	
IRR	% per annum	8.68	11.92	

Table 8.6: Commercial Characteristics of an IGSC Retrofit

Notes:

1. A full sensitivity analysis spreadsheet has been prepared and could be made available for the evaluation of specific applications of IGSC.
2. The finance gearing is taken as 70% loan 30% equity.
3. The loan is paid back over fifteen years at 1% over Libor.
4. The stated efficiencies both assume retention of the old steam turbine together with its feed water heating system. This means that waste heat from the oxyburn cycle cannot be used for this preheat duty. If a new Steam Turbine were to be used to replace the existing steam turbine then, for example, the efficiency of the overall plant (including the ASU) would rise to 32%.
5. The ascribed figures are given as typical of today's markets.

6. The oxygen price has been obtained from international suppliers of very large scale ASU's who would be prepared to supply oxygen both over-the-fence or within the battery limits as part of the main plant.
7. Excludes initial year of operation when availability has been assumed to be 70%.

Conclusions

The development of IGSC would considerably enhance the potential contribution of UK industry to further the control of global carbon emissions.

The initial challenge will be to develop sufficiently commercially attractive CCS scheme to justify its cost in terms of reward, extent of carbon capture, and effect on generating capacity.

It is a relatively simple achievement to capture 100% of CO_2 by using oxygen for total combustion. The challenge is to achieve this without substantial reductions in generating efficiency and power station output.

- The technology is a novel means of generating power from what is normally regarded as dirty fuel with the capability of capturing all the resultant by-product CO_2.
- It can be used effectively to retrofit the entire global fleet of existing coal burning power stations resulting in increased global power generating capacity and a substantial reduction in CO_2 emissions.
- The technology is proprietary to the UK and therefore will be beneficial to UK exports.
- There is no discharge to atmosphere but there is a significant by-product of water.

List of Contents

1.0 INTRODUCTION, SCOPE AND OBJECTIVES

1.1 Background

In April 2006, Jacobs Consultancy, together with five other consortium partners, submitted a proposal for the study of a new means of producing power from coal with 100% CO_2 capture. This was to be funded under the Low Carbon Initiative scheme. The process was entitled 'Integrated Gasification Single Cycle' (IGSC).

The proposal was short-listed in June 2006 and a final decision to award a grant given in October 2006. A collaboration agreement was drawn up and signed by the consortium partners before the end of December 2007. At that time, one of the proposed partners dropped out leaving Siemens, CO_2 Global, MAN and Imperial College, led by Jacobs Consultancy. DTI confirmed the grant in January 2007 and a starting date of 25th January 2007 was agreed, with a Project duration of 18 months.

The IGSC scheme developed involves an initial coal gasification step (partial oxidation using high purity oxygen) followed by complete combustion of the syngas in new burners developed by Clean Energy Systems (CES) of California. These also use high purity oxygen for combustion, with the final combustion temperature being moderated by water addition i.e. total combustion in a two-step process.

Essentially, only steam and CO_2 are the products of combustion and, after expansion to generate power; the heat in the exhaust "flue gases" is used to raise HP steam in a specialist Heat Recovery and Steam Generator (HRSG) which cools the "flue gases" down to near the water condensation point. These then pass to a Desaturator system which both separates the CO_2 from the steam and recovers all the remaining sensible and latent heat for raising LP steam. All the steam is used to power clean steam turbine/generators to complete a "combined cycle". The by-product CO_2 is separated and compressed for export for Enhanced Oil Recovery (EOR) or storage. The condensed water is recycled to the gasifier and the CES burners as a partial oxidation and combustion temperature moderator.

One of the conditions of the grant award was to conduct a six months review of the Project to make an early go/no go decision on proceeding with the full cost estimate once the basic technical solution had been established.

Available schemes already proposed by various parties in the past for the commercial application of the CES burner in a plant to generate power from coal were found to have very low and therefore commercially unacceptable thermal efficiencies. Jacobs set out to develop its own scheme; building on its experience in designing coal based power plants using the gasification of coal. This resulted in the Integrated Gasification Steam Cycle (IGSC).

After proving the study concept i.e. following the development of a mass and energy balanced computer simulation of the flowscheme, its performance and probable capital cost was compared (favourably) with the competitive options. It was therefore jointly decided to carry out at least the preliminary designs for:

- A Utility plant
- An existing plant Retrofit

Also it was decided to investigate the possibility of a Demonstration/Industrial scale plant.

Powerfuel, the developers of the Hatfield (South Yorkshire) IGCC 900 MW Power Project , have offered to host the Demonstration/Industrial scale plant on their site and make available a side-stream syngas supply from that plant which is currently being incorporated into the design of their IGCC plant. At the same time, the by-product CO_2 would be incorporated into the main captured CO_2 pipeline from the IGCC plant which is designed to capture up to 90% of its own CO_2 by-product. By obviating the need for a gasification system and a CO_2 export pipeline; this would considerably reduce the cost and schedule of a Demonstration/Industrial scale plant.

Capital cost estimates for the Utility and Retrofit designs were to be prepared together with the approach to building a Demonstration/Industrial scale plant.

This IGSC plant design is intended to be marketed in the Electricity Supply Industry (ESI) to help to provide a new era of emission free coal based power stations. The ESI has very high requirements for the operating reliability and availability of the technology which it uses. Therefore proponents of innovative technology are inevitably presented with a formidable challenge to meet these requirements. The industry would much prefer to use only already commercially proven favorites. However IGSC plant comprises equipment commercially proven other than the ‘hot gas expander’ which is a modification of existing equipment to suit this new duty.

1.2 Goals and Objectives

The main objective of the Project, as stated in the final submission for funding, was to produce costed designs for new and retrofit coal-based power stations incorporating near 100% carbon capture.

The prime innovation was described as a coal gasification module producing clean syngas for feeding to a new high temperature high pressure oxyburner. This raises superheated steam, by combusting fuel gas with oxygen using water as a temperature moderator, without the need for any coal-fired boiler, including any steam raising and superheater tubing. The products of combustion, which are mainly steam (c80%) and carbon dioxide gas contained within the steam, is expanded to generate power, leaving the carbon dioxide for capture and compression for export to storage without the need for any expensive and energy consuming scrubbing process.

Also advantages were cited as to the absence of a flue gas discharging to atmosphere and a net production of increasingly valuable water.

On confirmation of the funding being available, these goals were then taken as the objectives and listed briefly as designs and costings for three cases of power generation:

- a base case leading to a utility scale design
- a retrofit design
- a demonstration design of an industrial scale size

After proving the study concept (i.e. following the development of a mass and energy balanced computer simulation of the flow scheme), its performance and probable capital cost was compared (favourably) with the competitive options. The Consortium and the DTI therefore jointly decided to carry out at least the preliminary designs for:

- A Utility plant
- An existing plant Retrofit

and only to investigate the prospects for a Demonstration/Industrial scale plant.

1.3 Anticipated Benefits

The members of the Consortium very much aware that existing proposed CCS schemes were perceived as commercially counterproductive in that the effects on operating efficiency and capital cost per unit output of electricity were both negative.

In order for CCS based on IGSC to be seen as more beneficial rather than detrimental to already scarce power generating capacity and finance, it was determined to aim for benefits of improved plant output with a minimum loss in operating efficiency.

It was also appreciated that by using 100% oxy-combustion all the hydrogen in the fuel would be converted to water contained within the plant. However it was optimise that it would be difficult in the first development of a new electricity generating process to quantify exactly where this water would manifest itself in the initial water balance. It was therefore decided to state how much water this would be but not to take any financial credit for it at this stage of development.

1.4 Technologies Selection

The choice of technology was effectively determined through the development of the process and that is discussed briefly below.

In order to reduce the time and cost of development to commercial applicability, it was decided to use as much as possible already commercially proven technology and items of equipment.

The process was initially perceived as containing four elements:

- Gasification of coal to produce a particulate-free high pressure fuel gas
- Firing of that fuel gas into an expander to generate power
- Recovery of the exhaust heat
- Separation of the spent steam and CO_2 to leave only CO_2 for export.

This meant that the major items of equipment to be chosen constituted:

- Air Separation Units (ASUs)
- Gasification systems

- Hot gas expanders (the CES burner was already a chosen element of the equipment)
- Heat recovery systems working in hot exhaust gas
- Steam turbines
- Condensing steam/CO_2 separation systems
- CO_2 compression

It was optimise at an early stage that the system was effectively a combined-cycle. In order to get the full advantage of the combined-cycle, all the heat entering the front end via the gasification system would have to pass through both stages of power generation i.e. hot expansion and steam cycle in order to achieve the maximum possible power generating efficiency.

This requires that all the energy in the coal feed passes from the gasification system into the inlet of the hot expander.

Gasifiers in general have a thermal efficiency in the region of 80%. That is 80% of the chemical energy in the feedstock is converted to combustible syngas and the other 20% is released as sensible heat. This heat may be used directly to raise steam, but in this case, all the heat should preferably be contained in the syngas for entering into the hot expander. Hence the gasifier should be fitted with an exit water quench such that all the heat from the coal is converted into a steam/fuel gas mixture to pass on to the CES burners at the inlet of the fired expander.

More details and other similar developments of choice of technology and equipment are discussed in Section 3 and particularly in Section 3.8 “Specialised Equipment”.

2.0 DESIGN BASIS

2.1 Design Philosophy

The IGSC concept is to be developed principally for marketing in the Electricity Supply Market which provides a public utility with extremely high standards for operational availability and reliability. Innovative technology presents a formidable challenge to meet these standards as the industry would prefer to use only already commercially proven favorites.

Under these circumstances, and in any case because the development time for radically new equipment is long and uncertain, it is deemed sensible to optimise as much as possible commercially proven equipment in the designs.

Of course, it would be near impossible to produce an innovative and competitive improvement, which is better than the present technology, without using some elements of design and equipment which will be new to the market.

A philosophy of optimised as much commercially proven equipment as possible is followed throughout this development.

2.2 Case Definition

The Project Objectives involve a number of Cases:

- Base Case – First closing of the cycle which establishes the computer simulation model and thus the technical viability of the flowscheme
- Utility Case – Enactment of the Base Case design as a new build Greenfield plant. This Case is used for the Capital Cost Estimate
- Retrofit Case – An illustration of how the IGSC flowscheme could be used to retrofit an existing coal fired power station. This Case is used as the basis for the Economic Analysis
- Demonstration/Industrial Case – A minimum scale plant which could be used both as a demonstrator of the special features of IGSC and also as a dedicated Industrial Scale Plant for the use of industrial electricity consumers.

2.3 Site Location and Data

General information on the site is provided in Table 2.1.–

Item	Restrictions
Plot area restrictions (size, special construction requirements and access to existing equipment)	None
Site topography / site preparation requirements	Level, minimum site preparation required
Restrictions to vision	None

Table 2.1 – General Site information

Location

For the purpose of this study, the IGSC power plant is located in NE England as data is readily available.

Meteorological Data

The meteorological data of the site are given in Table 2.2.

Elevation above mean sea level	4 m
Barometric Pressure Minimum: Maximum: Average:	990 mbar 1035 mbar 1015 mbar
Design conditions	
Max temperature (dry bulb)	32.0 °C
RH	60%
Min temperature (dry bulb)	-10°C
Winterizing temperature (dry bulb)	-10ºC
Design Conditions for Guaranteed Output	
Max Temperature (dry bulb)	25°C
Relative Humidity	60%
Min temperature (dry bulb)	-10°C
Design Conditions for performance calculations	
Ambient dry bulb temperature	9.5 °C
Relative Humidity	60%
Air Cooled Exchangers	
Dry Bulb Temperature	25°C
Relative Humidity	40%

Table 2.2 – Site Conditions

2.4 Definition of Battery Limits

For the purpose of the study, the Battery Limits of the IGSC and interconnecting pipelines are defined as:

- The gatehouse where the coal / rail trucks enter and leave
- The gatehouse where road lorries enter and leave
- The gatehouse where the slag / rail trucks enter and leave
- Sulphur-containing by-product export point, which will be either in the form of sulphuric acid or gypsum[2].
- Raw water inlet pipe flange

- Natural gas inlet pipe flange
- Oxygen. Either oxygen inlet pipe flange or the air inlet of the ASU unit[1]
- CO_2 export pipe flange
- The high voltage side of the step up transformer that connects to the HV electricity grid connection
- Public sewer pipe flange
- Storm water pipe flange

2.5 Feedstocks and Products

Feedstock Specification – Coal

Average coal properties used for performance calculations are provided in Table 2.3.

Moisture Free Proximate Analysis		Moisture Free Ultimate Analysis	
Component	**% by Weight**	**Component**	**% by Weight**
Moisture	0.0	Ash	8.46
Volatile Matter	33.60	Carbon	74.95
Fixed Carbon	57.94	Hydrogen	5.45
Ash	8.46	Nitrogen	1.59
TOTAL	**100.00**	Chlorine	0.51
		Sulphur	2.30
Gross Calorific Value, kJ/kg	30,182	Oxygen	6.74
		TOTAL	**100.00**

Table 2.3 – Coal Properties Used for Performance Calculations

Hardgrove Grinding Index	=	55
Size	=	95% ≤ 50 mm
Moisture Content	=	10.5 wt% As Received

[1] The scope of study considers two scenarios where ASU is on either within or outside the battery limits of the plant. In the latter case the oxygen and nitrogen required for the IGSC plant is sold 'across the fence', thus increasing OPEX costs but reducing CAPEX costs.

[2] The actual product depends on the selected sulphur removal treatment.

Ash properties of the coal are given in Table 2.4.

Ash Analysis				
Compound	% by Weight		Ash Fusion Temperatures (Reducing)	
SiO_2	39.20			Mean (°C)
Al_2O_3	27.90		Deformation	1180
Fe_2O_3	20.70		Hemisphere	1300
Ti_2O_3	1.30		Flow	>1400
CaO	1.70			
MgO	1.20			
Na_2O	2.20			
K_2O	3.00			
P_2O_5	0.20			
SO_3	1.40			
Mn_3O_4	0.10			
Others	1.10			
TOTAL	100.00			

Table 2.4 – Coal Ash Properties Used for Performance Calculations

The coal specification selected represents typical world traded coal currently used in conventional CFB plants.

Product Specification – CO_2 Purity

The CO_2 specifications are given in Table 2.5.

	Limit / Basis	Reason
CO_2	≥ 95%	MMP concern [2]
N_2	≤ 4%	MMP concern [2]
Hydrocarbons	≤ 5%	MMP concern [2]
H_2O	≤ -40°C [3]	Corrosion
O_2	≤ 100 ppmv	Corrosion
CO	≤ 0.1%	Safety and corrosion
Hg	5 ppbw	Pollutant
Sulphur Compounds	35 ppm [4]	
Temperature	≤ 50°C	
Pressure	100 bara	Required pressure for sequestration

Table 2.5 – CO_2 Purity / Specifications

[2] Minimum miscible pressure concern, because the application of the CO_2 may be for EOR

[3] Dew point is –40 °C

[4] Sulphur content of CO_2 will be reduced by a suitable process

2.6 Utilities

The site is not integrated with any other facilities; the following utilities are available at the battery limit of the plant:

Raw Water

This water is used as make-up water for:

- Closed circuit cooling water make-up (blowdown and drift losses)
- Process water make-up
- Demineralised water, DMW, make-up

The raw water analysis is given below, in table 2.6:

Parameter	Value	Unit
Suspended solids (at 105°C)	10	mg/l
PH	7.4	pH units
Total Alkalinity as $CaCO_3$	85	mg/l
Conductivity (at 25 °C)	641	µS/cm
Chloride (as Cl)	66	mg/l
Chemical Oxygen Demand	<5	mg/l
Biochemical Oxygen Demand	<2	mg/l
Iron (as Fe)	0.18	mg/l
TPH FTIR	0.3	mg/l

Table 2.6 – Raw Make-up Water Analysis

Conditions:

Supply Temperature	Normal	10°C
Return Temperature	Normal	20°C
	Maximum	30°C
Supply Pressure	Normal	5 bar(g)

It is assumed that there are no restrictions on raw water consumption rates.

Natural Gas

Natural Gas is required for start-up and operation of the plant at upset conditions.

Natural Gas is supplied to the battery limits at the following conditions:

Temperature	15°C
Pressure	40 bar(g)

Natural Gas composition is summarized in table 2.7:

Component	Typical mol %
Methane	84.19
Ethane	4.91
Propane	1.57
Butane	1.14
Nitrogen	8.19
Total	100.00

Table 2.7 Natural gas composition

Electricity

The electrical system will be designed to integrate the on-site power generation equipment with the site process and all utility loads. If oxygen is bought over the fence then the ASU will be built and operated by another company and it will import the required load from the local grid. The electrical system will also provide connection to the local grid at the plant's battery limits. The system will be designed to allow for both power import and export.

A.C. Supply:

(a) 400 kV, 3-phase, 50 Hz

(b) 33 kV, 3-phase, 50 Hz

(c) 11 kV, 3-phase, 50 Hz, +6%, -6%

(d) 400 V, 3-phase, 50 Hz, +6%, -6%

(e) 230 V, 1-phase, 50 Hz, +6%, -6% - for supplying lighting and small power

(f) 110 V, 1-phase, 50 Hz, +10%, -6% - high availability, battery backed essential control and instrument supply

D.C. Supply:

(a) 110 V dc – for control of switchgear, electrical protection and interlocking

(b) 24 V dc – instrumentation control voltage derived within DCS

Oxygen

For the base and utility cases, oxygen shall be made available by the ASU operator at the following conditions:

Oxygen	≥95	mol%
Nitrogen	≤3	mol%
Other inerts	≤2	mol%

For the retrofit case, oxygen shall be made available by the ASU operator at the following conditions:

Oxygen	≥99.5	mol%
Nitrogen	≤0.3	mol%
Other inerts	≤0.2	mol%

The oxygen purity was raised for the retrofit case following discussions with Air Products to reduce the possibility of sulphuric acid formation in the desaturator. Economic analysis shall utilise this quality and its cost.

For the Demonstration/Industrial case, oxygen purity will depend on the quality of the locally available oxygen supply.

In all cases, oxygen will be provided at:

Temperature and pressure to be defined by the ASU operator.

Potable & Utility Water

Potable water is available at the battery limits at:

Pressure	3.5 bar(g)
Temperature	10°C

Closed Circuit Cooling Water

Cooling is provided by a closed circuit cooling water system using mechanical draft cooling towers. The cooling water conditions will be developed further during the project.

Supply:

Design Temperature	26.5°C
Pressure	4 bar(g)
Maximum temperature rise	10 °C
Maximum pressure drop	1 bar

Demineralised Water

Demineralised water is generated within the battery limits at the following conditions and specifications:

Pressure	5 bar(g)
Temperature	10 °C

Parameter	Units	Value
Total Dissolved Solids	mg/l	0.5
Suspended Solids	µg/l	10
Free Hydroxide Alkalinity		0
Total Hardness		0
Sodium	mg/l as $CaCO_3$	0.1
Total Silica	µg/l as SiO_2	10
Total Iron, Copper, Nickel	µg/l	20
Ammonia	mg/l as $CaCO_3$	0.1
Total Cations	mg/l as $CaCO_3$	0.2
Free CO_2		0
Sulphate		0
Nonvolatile TOC	mg/l as C	0.2
Oily Matter	mg/l	0.2

Table 2.8 Demineralised Water Specification:

Instrument & Plant Air

Instrument & Plant Air is available at the following conditions:

Pressure	8 bar(g)
Temperature	Ambient
Dew Point	-40 °C

Nitrogen (for purging, inerting and start-up)

Nitrogen is imported from the outside Battery Limits ASU and supplied to the plant at the following conditions and specifications:

Pressure	8 bar(g)
Temperature	Ambient
Dew Point	-40°C

Steam and BFW

Steam is generated at the following conditions:

HP Steam (Superheated)

Pressure	135 bar(g)
Temperature	600°C

IP steam (Superheated)

Pressure	40 bar(g)
Temperature	600°C

LP steam

Pressure	5 bar(g)
Temperature	215°C

BFW is provided at:

Pressure	145 bar(g)
Temperature	45°

2.7 Overall Design Criteria

Operating Mode

All the design cases are to be based on a full load operation only on the specified coal, i.e. no other solid fuel is considered.

Availability and Spares

It is expected that the availability of the plant is to at least equal existing coal and syngas power plants which is a minimum of 85% operating on the specified coal.

The choice of spares is then dictated by economical considerations subject to maintaining the necessary availability. To maintain availability, all rotating equipment in the syngas treatment plant, except compressors, steam and gas turbines and generators, have installed spares on a "plus one" basis, i.e., one 100% pump has a 100% spare; two 50% pumps have one 50% spare.

Major rotating equipment such as the CO_2 compressor, air compressor and turbines are not spared. The CES burner will not be spared either.

All new units are designed for an operating life of 30 years. Internals of various equipment will have a shorter life and will be replaced as required.

A stand-alone process control system and central control room are provided.

Equipment Design Criteria

Applicable International standards and codes such as ASME, API, BS, CSA and ISA are used in this study.

Interconnections and Potential Leakages

All interconnections between units and individual items of equipment are located to reduce the risk of cross-contamination. Heat exchange between dissimilar streams is minimised. Where this cannot be avoided, the following hierarchy is followed:

- No direct interchange between oxidising and fuel streams so that flammable gas cannot leak into oxygen containing streams, or oxygen leak into flammable streams - especially pure oxygen streams, or those feeding the ASU.
- Clean streams are kept at higher pressure than contaminated streams to prevent clean streams, such as the gas turbine fuel stream or steam to the steam turbine becoming contaminated, particularly with H_2S.

Heat Exchangers

Heat exchangers are designed with a minimum approach of 10°C with the exception of steam turbine and steam generating systems where a minimum approach of 5°C (which is the standard for the power generation industry) is used.

Cooling Heat Losses

A high plant thermal efficiency is sought by reducing heat losses to the cooling water system by optimal heat integration.

Design Margins

Unit	Margin
Overall Pressure Profile	Pressure profile allocations are at 100% capacity; maximum capacity for feed pressure, maintaining control valve range ability is approx 110%
Heat Exchangers and Pumps	10% on normal duty unless there is a more severe duty case.
Centrifugal Compressor – Motor driven	10% margin on flow and discharge pressure
Screw Compressors – Motor Driven	10% on flowsheet flow and head
Reciprocating Compressors – Motor Driven	10% on flowsheet flow at reduced suction pressure and 10% on head
Vendor Packages	Specify for 100% flow, margin to be included by vendor only

Table 2.9 Design Margins

2.8 Environmental Criteria

Atmospheric Emission Limits

The NO_x limit is 25 ppmvd at 15% O_2 and the SO_x emissions limit is equivalent to 20 ppmv of sulphur in the undiluted syngas.

Liquid Discharge

All liquid discharge streams must be treated within the site battery limits before being discharged into a standard waste water treatment unit. The specification of waste water is as follows:

Component	Limit, mg/l
BOD	< 300
COD	< 1000
Phenolics	<30
Oil	<50
Total Heavy Metals	< 0.5
Copper	Incl. in above
Iron	Incl. in above
Nickel	Incl. in above
Cadmium (VI)	Incl. in above
Mercury	Incl. in above
Vanadium	Incl. in above
Tin	Incl. in above
Zinc	Incl. in above

Table 2.10 – Waste Water Discharge Specifications

Solid Discharge

Slag and any other solid compounds will be considered as by-products, which can be sold. Apart from sulphur, for the purposes of this study, the sale price of all other solids is assumed to cover the cost of transport, and, therefore, these solids have no impact on the operating costs / revenues. Any hazardous solid waste is to be sent to a controlled landfill. The volume must be minimised.

Noise Limits

The noise limits are given in Table 2.11.

New Power Plant	Existing Power Plant
85 dBA at 1 m *	85 dBA at 1 m *

Table 2.11 – Noise Limits

* Workers can request protective hearing equipment for noise levels above 80 dBA

2.9 Units of Measurement

The units of measurements used in the study are metric and are given in the table below:

Measurement	Description	Abbreviation
Length	Metre	m
Area	Square metre	m^2
Temperature	Celsius	° C
Volume	Cubic metre	m^3
Volume Flow Liquid	Cubic metre per hour Cubic metre per second	m^3/h m^3/s
Pressure	Bar gauge Bar absolute	bar(g) bar(a)
Volume Gases @ 1.013 bar(a) and 0 °C	Normal cubic metre	Nm^3
Volume Flow Gas	Normal cubic metre per	Nm^3/h

Measurement	Description	Abbreviation
	hour	
Velocity	Metre per second	m/s
Weight (Mass)	Kilogram Tonne	kg t
Molecular Mass	Kilogram mole	kmol
Molecular Weight	Kilogram/kmol	
Density	Kilogram per cubic metre	kg/m^3
Mass Flow	Kilogram per hour Tonne per hour	kg/h t/h
Force	Newton	N
Moment of Force	Newton metre	Nm
Stress	Newton per square metre	N/m^2
Energy	Joule	J
Power	Watt	W
Viscosity	Centipoise Centistokes	cP cSt
Heat Transfer Coefficient	Kilowatt per square metre Celsius	kW/m^2 °C
Heat Capacity	Kilojoule per kilogram, degree Celsius	kJ/kg °C
Thermal Conductivity	kilowatt per metre, degree Celsius	kW/m °C
Latent Heat	Kilojoule per kilogram	kJ/kg
Current	Amps	A
Voltage	Volts	V
Frequency	Hertz	Hz
Concentrations	Parts per million weight Parts per million volume Parts per million volume	ppmw ppmv ppmvd @ 15%O_2

Measurement	Description	Abbreviation
	diluted to 15% O_2 Micrograms per cubic metre Milligrams per cubic metre Milligrams per litre Weight percent Mole percent Volume percent	 µg/m³ mg/m³ mg/l wt % mol % vol %
Noise	decibel	dB (A)
Revolutions	Per minute	rpm
Time	Second Hour Year	s h a
Air Humidity	Percent relative humidity	% RH
Piping Normal Size	Inches	in (“)
Fouling Factor	Square metre, degree Celsius per kilowatt	M^2 °C /kW
Surface Tension	Newton per metre	N/m
Conductance	Siemens	S
Corrosion Allowance	Millimetre	mm

Table 2.12 – Units of Measurement

Prefixes for Multipliers

10^3	k	(kilo)	10^{-2}	c	(centi)
10^6	M	(mega)	10^{-3}	m	(milli)
10^9	G	(giga)	10^{-6}	µ	(micro)

3.0 PROCESS AND PLANT DEVELOPMENT

3.1 Introduction

The basic process principles of IGSC are initial conversion of a dirty fuel into a clean high pressure gas which becomes the feed for a combined cycle comprising of a Brayton hot expansion cycle followed by a steam Rankine cycle. This unique combined cycle is an efficient means of utilising fossil fuel energy through:

- initial combustion in a Fired Expander to generate power
- using the exhaust heat from the hot expander to raise steam in a Heat Recovery Steam Generator (HRSG)
- feeding that steam to a conventional condensing Steam Turbine to generate power.

The experience and lessons learnt in the development of other combined cycles, both for NGCC and IGCC, and available from within the Consortium, are heavily drawn upon in the development of IGSC.

The make-up of the Consortium partners provides access to a large range of proven hot power expanders, steam raising heat recovery boilers and steam turbines, from which selected models can be adapted to fit the specific requirements of the IGSC cycle.

3.2 Features of Design

The major differences between a conventional Natural Gas Combined Cycle (NGCC) and Integrated Gasification Steam Cycle (IGSC) are:

1. Because near-pure oxygen is used for combustion, there is no need for a large integral air compressor as incorporated in conventional gas turbines, and only a simplified expander is retained from the original gas turbine design.

2. The “flue gas” from the Fired Expander consists mainly of steam with around 20% CO_2 rather than the conventional flue gas of nitrogen, oxygen and CO_2 in a NGCC.

3. In order to optimise the energy cost of compressing the captured by-product CO_2 left after condensation of the steam in the “flue gas”, the back-end of the HRSG is run art an

elevated pressure of around 10 bar. This entails running the Fired Expander exhaust at about 2 bar above that to allow for pressures drops throughout the HRSG and final cooling of the "flue gas".

4. The steam content of the "flue gas" is separated from the CO_2 by counter-current direct quenching with cold water in Desaturators. Desaturators are commonly used in the chemical industry to separate non-condensable syngases from evaporated water and are specifically applied in methanol and ammonia synthesis plants, of which Jacobs has extensive experience.

5. The main body of the plant is run in a sulphurous condition i.e. with all the sulphur in the coal feedstock being retained in the "flue gas" as SO_2 which is removed during the compression of the captured CO_2. It is essential therefore, that for materials protection, that the "flue gas" does not fall below the Acid gas Dewpoint Temperature (ADT) in any section of the plant whose materials of construction are not pre-selected to withstand acid condensation. For this reason:

   a) Start-ups and shut-downs will commence and end respectively using a sulphur free feedstock such as natural gas and sulphurous syngas will not be admitted – unless and until the plant is at normal working temperatures

   b) The HRSG is designed such that its "flue gas" exit temperature, and that of all feedwater admitted to the HRSG, is above that of the ADT. Final cooling to the water dewpoint temperature before entry to the Desaturator will be carried out in coolers/heaters using acid resistant materials of construction.

6. The IGSC offers a unique opportunity for the application of a novel means of acid gas control, and the removal and recovery of sulphur.

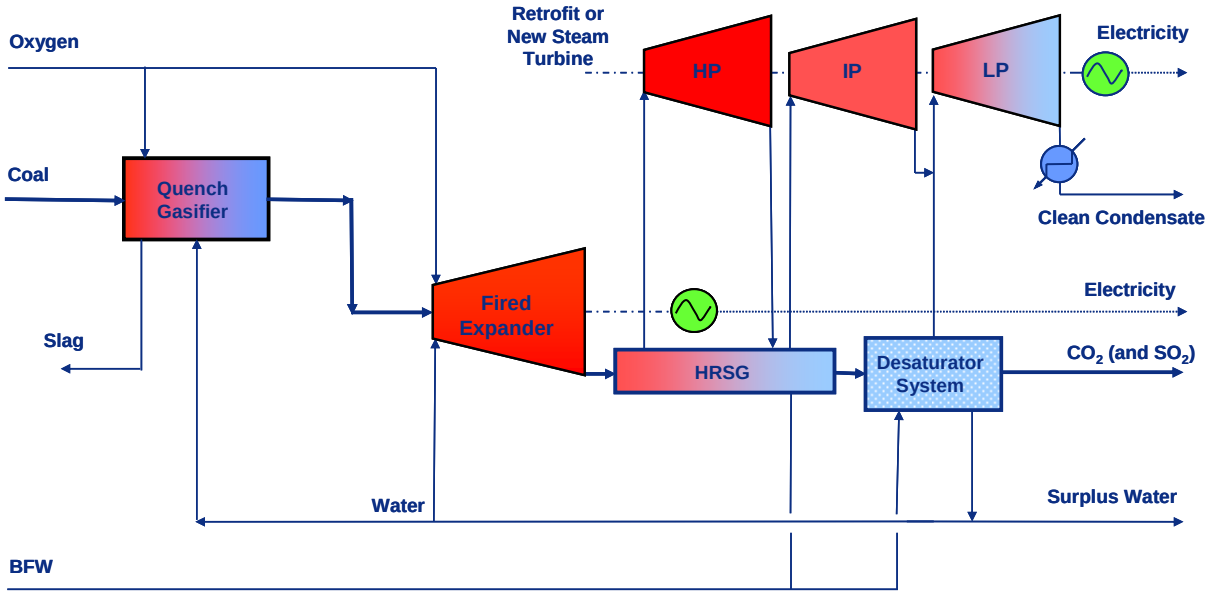
   It has always been recognised in IGCC design that the location of a near-ambient temperature sulphur depletion step operating between the gasification and power islands is very detrimental to both capital cost and operating efficiency

   For IGSC, sulphur compounds, i.e. initially H_2S and COS after gasification, and essentially only SO_2 after total combustion, are left in the syngas throughout the plant and removed from the by-product CO_2 during compression for transportation to storage or for EOR.

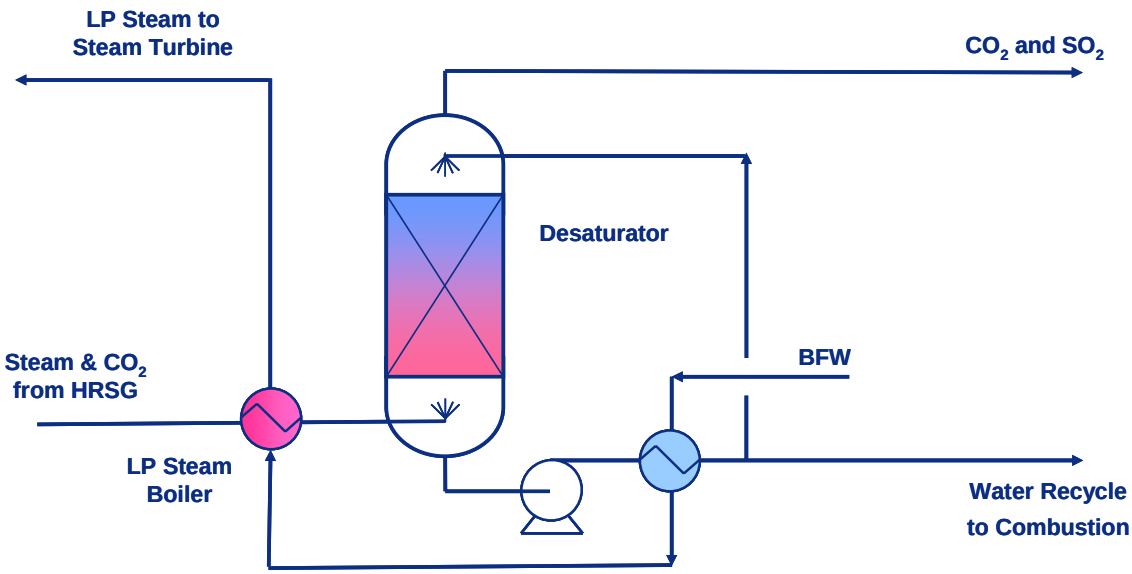
7. Most important, IGSC can be used to retrofit existing coal-fired power stations resulting in 100% CO_2 capture and an increased electricity output of 70%. All of the existing equipment could be incorporated into the retrofitted plant with the exceptions of the boiler and stack which become redundant. This takes the maximum opportunity of existing assets.

IGCC cannot offer this sort of capability.

The IGSC overall flow scheme is shown below along with the typical desaturator system.



IGSC FLOWSCHEME



DESATURATOR SYSTEM

Figure 3.1: IGSC Flow Scheme

3.3 Generic Process Description

3.3.1 Gasification

Gasification was originally called Partial Oxidation or POX. In the case of coal feedstock, POX or gasification uses in the order of 40% of the oxygen required for stoichiometric combustion to convert the chemical energy in the coal to a low calorific value combustible gas (syngas) composed of carbon oxides (predominantly carbon monoxide and hydrogen). For the entrained flow gasifiers favoured for power generation application, there will be less than 1% methane and hydrocarbons in the syngas. The gasification temperature has to be sufficient to melt the ash associated with the coal in order to achieve complete penetration and therefore a high carbon conversion efficiency. The temperature is controlled by water or steam moderation, the water contributing the hydrogen generated in the gasification reactions. The exact proportions of coal, oxygen and water are set by the gasification licensor based on the characteristics of the coal.

The sulphur in the coal feedstock is converted primarily to SO_2 with a small amount of COS. The inorganic material in the feed is melted by the partial combustion heat and cooled in the quenching of the hot syngas to form a vitreous non-water leachable slag that is disposed of off-site.

In order to take full advantage of the combined cycle, it is vitally important that as much as possible of the energy in the coal feedstock enters the effective “throat” of the combined cyc–e - which is the inlet to the Fired Expander i.e. the feeds to the CES burners. This means that there should be no syngas heat or flow removal between the gasifier and the fired Expander. This is achieved in practice by using a water quench gasifier which converts the heat of the syngas into admixed steam.

There are three commercially available water quench coal gasifiers:

- GE Energy (née Texaco)
- Shell
- Siemens

Thus all the chemical energy in the coal is converted into combustible syngas or steam.

Following the water quench, the syngas is scrubbed thoroughly with recycled water and finally clean water to remove essentially all particulate matter. The particulate free raw syngas/steam mixture leaves the gasifier system at a temperature in the region of 250° C. The term "raw" refers to the gaseous impurities and sulphur compounds in the syngas.

At this point in the flowscheme, there is an opportunity to extract some syngas for separate treatment to co-generate hydrogen for use in chemicals production. Any extraction of syngas will, of course, reduce the power generating efficiency of the process, but the loss in efficiency as a result of co-generating hydrogen in an IGSC plant would be the same as for a co-generating IGCC plant.

The blowdown water from the quench system is treated and a portion is recycled to the coal slurry preparation area and the gasifier vessel. The remaining water is sent to the waste water treatment plant for further treatment and recovery of water

The water saturated raw syngas stream from the scrubbing system is superheated in an indirect heat exchanger to obviate the possibility of water condensation, and fed to the Fired Expander CES burners' fuel control system.

3.3.2 Fired Expander

The proprietary CES burners are mounted in the firing chamber of a commercial gas turbine which has had its air compressor removed. The CES burners replace the normal air/natural gas burners.

The CES burners have been extensively tested in operation in California and a tightly controlled fuel feed system developed. The triple feeds are controlled and monitored as follows:

- Fuel rate – as per load requirements
- Oxygen rate – ratio controlled to the fuel rate to achieve stoichiometric combustion
- Water rate - to regulate outlet temperature and therefore the firing temperature of the Fired Expander.

More details of the fired Expander are contained in Section 3.8.1 below.

3.3.3 HRSG

The hot gas exhaust from the Fired Expander enters the Heat Recovery Steam Generator (HRSG). This is a conventional water tube boiler/superheater raising and superheating steam through coils inserted in the hot 80/20% steam/CO_2 "flue gas". The "flue gas" is at a pressure of 10-12 bar pressure which is higher than that of atmospheric HRSGs which recover heat from gas turbine exhausts. However, it is lower than that of waste heat boilers mounted on partial oxidation gasifiers. The duty, therefore, falls within the design parameter range which has already been built, supplied and operated.

The HRSG consists of two parallel units, recovering heat by raising high pressure superheated steam which is used in the condensing Steam Turbine to generate power. The HRSG also provides the reheat for the Steam Turbine HP to IP stage.

3.3.4 LP Steam Generation

After leaving the HRSG, the cooled "flue gas" is further cooled towards the Acid gas Dewpoint Temperature (ADT) by raising LP steam, and by heating boiler feed water fed to the HRSG. The LP steam may be used to supplement the LP section of the main Steam Turbine, or, if there is no spare capacity in the LP casing of the Steam Turbine, it may be fed to independent condensing Auxiliary Steam Turbines to generate further power.

Special attention is now given to the choice of heat exchanger materials of construction, to ensure resistance to potential acid attack. The "close to but not at" ADT "flue gas" is finally cooled down to just above the Water Dewpoint Temperature (WDT) and fed to the Desaturator system

More details of the HRSG are contained in Section 3.8.2 below.

3.3.5 Desaturator System

The Desaturator is a vertical vessel containing a section of packing materials that ensure intimate contact between the gaseous and liquid phases. The "flue gas" has its water content finally condensed by counter-current direct contact with cold water flowing down the Desaturator. The CO_2 thereby separated exits the top of the Desaturator and passes on to compression and

purification. The condensed water is recycled as temperature moderator to the two stage combustion system (gasification followed by CES burners).

The Desaturator system is similar to those familiar in large scale hydrogen, ammonia and methanol chemical synthesis plants to separate the water from water vapour/syngas mixtures.

The hot water leaving the bottom of the Desaturator, which contains the latent heat of the steam condensed from the “flue gas”, is used to raise further LP steam that is supplied to the Auxiliary Steam Turbine. Finally, after a blowdown stream is taken off to assist in the control of water quality and quantity (the system will contain extra water produced from the combustion of hydrogen in the coal feedstock), the water is recycled, still hot, to the combustion system.

3.3.6 CO_2 Compression

The by-product CO_2 is compressed to 100 bar for pipeline transport to either storage or for EOR. MAN Turbo multistage gear compressors are used, a type already in commercial operation for similar duties i.e. CO_2 compression to high pressure.

The compressor is inter-cooled and may incorporate a sulphur clean-up system, as discussed below in Section10.4 “”Future Development”. The compressor system also includes an inter-stage molecular sieve water removal system which is cyclically regenerated.

The elevated bottom pressure of the IGSC cycle which feeds CO_2 to the compressor at 10 bar, results in considerable savings over the normally proposed atmospheric pressure suction used in other CCS technologies. The energy required to compress the CO_2 from 10 to 100 bar is half that required to compress from atmospheric pressure to 100 bar, and the capital cost is a factor of five lower.

3.4 Base and Utility Cases

The Base Case is the first successfully converged solution of a full flow scheme simulator model – as defined in Section 2.2 “Design Basis”.

The chosen gas turbine whose expander is used is discussed fully in Section 3.7.1 below.

The Base Case design using the initial choice of gas turbine for modification, resulted in a theoretical plant design with a net output capacity in the order of 1200 MW operating at an

efficiency of 37.4%. However it was felt that this was too high an output power for a first of its kind power plant. Therefore it was decided to concentrate the main development and evaluation of the IGSC process on the Retrofit Case as discussed below in Section 3.5.1.

3.5 Retrofit Case and Flexibility

3.5.1 Retrofit Case

It was determined early on during the development work that the Utility Case output of 1200 MW was too large for the immediate utility market which is currently serviced by fossil fuel units which have capacities in the order of 500 MW. The recognition that this is effectively the "standard size" for power station grid contributions, coupled with the reality that the 1200 MW unit would have no operating experience support whatsoever, led to a redirection of the development effort.

Using IGSC to retrofit existing 500 MW Power Stations was considered a pragmatic and marketable option – especially at this time, when the UK Secretary for Business and Enterprise Secretary John Hutton was quoted as saying [1]:

"Our analysis shows that post-combustion capture is the most relevant technology to the vast proportion of coal-fired generation capacity globally," Hutton said in a statement.

"The capture technology can also be retro-fitted to existing coal-fired plants. This will be vital in tackling climate change on a global scale."

However, the approved budget permitted only one case to be designed, equipment developed and cost estimated. These tasks had already progressed for some time for the Utility Case when it was determined that the Retrofit Case would potentially be closer to the current UK market requirements.

It was therefore decided to complete the Utility case cost estimate and effectively scale this down to the size of the Retrofit Case and carry this forward as the basis for the Economic Analysis.

3.5.2 Flexibility

As the prime market for the IGSC technology is seen to be in retrofitting existing coal fed steam turbine/generator power stations, the following is directed principally to this application.

Power generating market strategies have considerably changed from the tradition of coal fired plant providing base load requirements with gas or oil used for peaking power plants. Today nuclear power together with gas plants provide the core of base load requirement maintaining a high and steady high production/consumption rate to avoid financial losses through "take or pay" arrangement.

Coal fed power stations now provide the flexibility in the system, being used as peaking plants, as for the UK:

All coal plants have "paid off the mortgage" and therefore run at marginal cost

Coal is readily stored in the vicinity of the power station meaning extra feedstock is available when required which may not be the case for natural gas.

However, in order to be truly regarded as peaking plant, these power stations must not only be able to move from a stand-by condition to on-line quickly, but also to be capable of turning down and running at low outputs. The Ferrybridge power station, used to illustrate the Retrofit Case in this document, can be turned down from 100% load to 40%.

Therefore to be a true retrofit, this degree of turn down should be replicated.

The CES burners can be turned down to as low as 10% of normal firing and therefore the Fired Expander can be turned down at least as far as 40%, but this would result in reduced heat content entering the HRSG. The HRSG design is capable of operating with these reduced flue gas conditions if the main Steam Turbine control is changed to sliding pressure for the HP casing. The HP cylinder efficiency reduces at part-load; however the IP/LP cylinder efficiencies can be maintained by use of a back pressure control valve situated in the reheat section between the HP & IP cylinders and controlling the exit pressure of the HP cylinder.

Exact plant following capability would be established during the detailed design phase for any given plant retrofit. However it should be noted that IGSC has equal or better turn down characteristics than conventional coal or gas fired power plants.

A typical arrangement of the retrofit IGSC flow scheme is shown below.

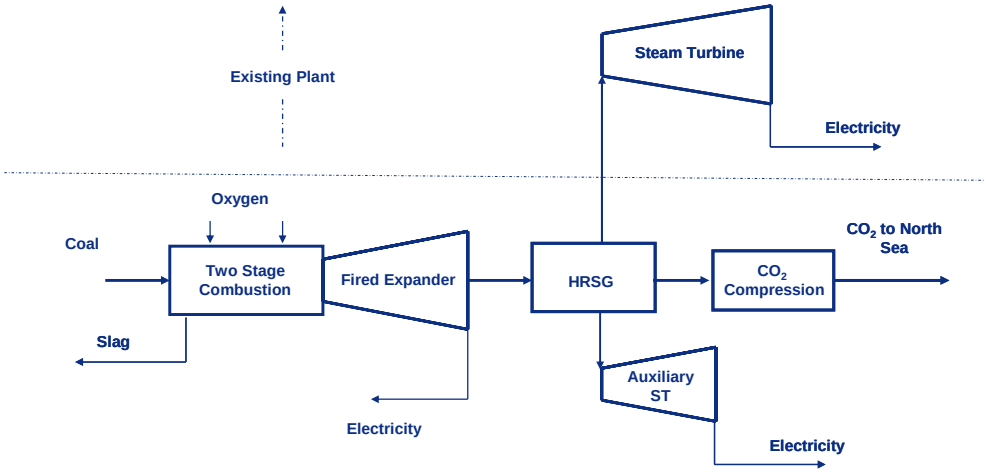


Figure 3.2: IGSC Flow Scheme for Retrofit

3.6 Demonstration/Industrial Case

The Demonstration/Industrial Case is designed to demonstrate the critical new features of IGSC at a minimum viable capacity and cost i.e. as small as possible but still exhibiting the essential features as discussed below.

It is also intended to see if such a scale plant (c50 -100MW) could be marketable in its own right as a power provider for industrial users.

At the outset of the Project, there was a possibility that the basis for this small scale plant could be taken from the Norwegian ZENG (Zero Emissions Natural Gas) Project [2], a development using the CES burner, which was launched before IGSC. However, the results from ZENG were

not considered appropriate as being incomplete and still being worked on and therefore the Demonstration/Industrial Case is based on a scaled down version of the basic IGSC design.

The essential features to be demonstrated in what would also be a prototype IGSC are:

1. Operation of CES burners “on line” with coal based syngas which has received no treatment other than water scrubbing to remove particulate matter i.e. still containing all the gaseous impurities associated with coal syngas especially sulphur compounds

2. Operation of CES burners “on line” with recycled hot water from the Desaturator which has received no treatment

3. Operation of a Fired Expander derived from an industrially proven gas turbine, whose blades are normally cooled with air, using recycled “flue gas” consisting of steam and CO_2 as the cooling medium

4. Recovery of the Fired Expander exhaust heat using a pressurised HRSG to cool the “flue gases” of steam and CO_2

5. Control of the plant and location of the Acid Dewpoint Temperature (ADT) of the “flue gases” to ensure that this always occurs downstream of the HRSG

6. Confirmation of the Desaturator as an effective steam/CO_2 separator with efficient heat recovery of low grade heat for use in raising LP steam

7. Investigation of integral sulphur removal as sulphuric acid during wet CO_2 compression

8. Confirmation of the best operating procedures for changing over feedstock especially from natural gas to syngas during start-up and vice versa at shut-down.

Note: All of these features may be preliminarily investigated on natural gas operation except for features 5 and 7. However even these may be investigated by use of an injection of carbon disulphide into the natural gas feed and a temporary precautionary caustic wash on the by-product CO_2. The ADT may be continuously monitored by an industrial ADT monitor [3]

3.7 Natural Gas Operation and Start-Up

There are two circumstances when the IGSC will be used with natural gas feedstock:

- In a dedicated design to generate electric power and CO_2 by-product from natural gas
- During start-up or shut-down of a coal fed IGSC when sections of the plant may be below ADT

Natural Gas Operation

IGSCs using natural gas feedstock operate similarly to coal based plant but with no gasification system to provide fuel.

The operating parameters of a natural gas fed IGSC are similar to those for coal operation.

Oxygen requirement is slightly higher and efficiency slightly lower.

The CES burners should also be dedicated and designed for natural gas operation if this is to be the normal mode.

Most importantly, natural gas is normally cleansed of sulphur compounds prior to any application or use. This obviates any problems arising from acid gas condensation and results in a much broader base of choice of materials of construction.

The most likely application for a natural gas fed IGSC would be in or near a partially depleted oil field where the CO_2 by-product could be used for EOR. A commercial natural gas fed plant using a similar cycle to IGSC is currently being built in the Californian inland oil fields for this purpose. This plant has a portion of state financial support

Start-Up

Any sulphur species in the IGSC plant feedstock will become sulphur dioxide contained wholly in the “flue gas”. This cannot be permitted to fall below ADT until it enters that part of the plant which is appropriately designed and fabricated to withstand condensed acid gas.

Therefore at start-up, a sulphur-free feedstock must be used and continue to be used until the working temperature in these prohibited zones at least exceeds the ADT.

The normal procedure for a sulphur containing coal-fed IGSC is to start up using sulphur free natural gas (or any other sulphur free gas such as LPG). Sulphur containing syngas is admitted to the Fired Expander, and thus the rest of the plant, only when the appropriate sections of the plant i.e. those not designed to withstand acid gas condensate are all above the ADT.

This procedure is reversed for a shutdown or during any temporary break in production.

Therefore the CES burners must be capable of dual-fuel firing without shutdown i.e. changing from natural gas to syngas online and vice versa. In order for the much higher CV natural gas to use the same burner channels as the syngas, and still be controlled using the same control system, the natural gas is diluted with CO_2 to the same Wobbe number as that of the syngas.

3.8 Specialist Equipment

3.8.1 Fired Expander

The final choice of source of equipment for the Fired Expander is the Siemens SG–5 - 4000F (née V94.3A) gas turbine. The expander is used as the basis for the Fired Expander in the Utility, Retrofit and Demonstration/Industrial Cases with the air compressor removed, along with the final one (for the Utility Design) or two (for the Demonstration/Industrial Case) stage(s) of the four stage expander.

In normal operation as a gas turbine, air from the gas turbine air compressor would provide:

- Combustion air for the natural gas combustors
- Cooling air for flame temperature control through fuel pre-mixing
- Attemperation to the permitted Turbine Inlet Temperature (TIT)
- Rotor, stator and turbine casing cooling

In IGSC operation, the Fired Expander would use:

- Pure oxygen attemporated with recycled water for fuel combustion
- Recycled “flue gas” for cooling.

This makes possible the removal of the air compressor.

Plus Points of SG–5 - 4000F

a) The superior top cycle temperature offered by this machine through its unique tile lined combustion chamber

b) The capability of effectively scaling up the most proven CES burner to the heat release quantity required for a front-line power station. This is achieved by the inherent ability of the burner system to accept the mounting of 24 x 200 MW_{th} CES burners in place of the conventional air/natural gas burners.

The use of the 200 MW_{th} CES burner will be supported by the testing and evaluation work currently being carried out at the CES's Kimberlina facility in California.

Development Points

a) The SG–5 - 4000F is designed to run as a near atmospheric pressure exhaust machine. For use in IGSC, the exhaust pressure will be raised to about 12 bar. This has been configured from an "inside machine" aspect and found to be mechanically acceptable – but a new overall pressure casing will have to be designed, open to the 12 bar exhaust, and capable of withstanding the firing pressure of 37 bar.

b) In order to permit the high firing temperature, internal and external cooling of the expander blades is essential. The normal cooling medium is air which, of course, cannot be used in an IGSC plant dedicated to providing CO_2 by-product with low nitrogen content and no oxygen.

Siemens would be content to use steam as an alternative cooling medium and the use of recycled CO_2 was studied as part of the project development and found to be marginally superior to steam. However both steam and CO_2 if used alone would create potential instability in the Desaturator (see Section 4.8.3) and the final solution is to use recycled "flue gas" (which is made up of approximately 80% steam 20% CO_2) as Fired Expander coolant.

This means that the entire plant with the exception of the pure steam boiler system contains this mixture. Even if the carbon/hydrogen ratio of the feedstock coal changes, thus changing the

analysis of the syngas and “flue gas”, the plant will still contain a homogeneous gas mixture and retain substantially the same dewpoint temperatures.

The coolant is taken from the back end of the HRSG, above any acid gas or water dewpoint temperature, and recycled to the Fired Expander by the centrifugal Coolant Recycle Compressor.

The rest of this section discusses and describes the development of the SG–5 - 4000F gas turbine expander to satisfy the Fired Expander capacity requirements of the Utility and Retrofit Cases including the fitting of CES burners.

Overview of CES Oxy-Fuel Burners

Clean Energy Systems, Inc. (CES) has developed zero-emission fossil-fuelled power generation technology, integrating proven aerospace technology into conventional power systems. The core of CES’ process is the “gas generator” technology adapted from rocket engines. The gas generator burns a combination of gaseous oxygen and any gaseous fuel composed primarily of the elements carbon, hydrogen, and oxygen. The combustion is performed at essentially stoichiometric conditions in the presence of recycled water to produce a mixed gas of steam and carbon dioxide at high temperature and pressure. The basic gas generator technology has been used successfully in aerospace applications for decades. CES’ innovation has been to adapt that aerospace technology to power generation, much like the process by which aircraft jet engines were adapted for aero-derivative gas turbines in conventional power plants.

The gas generator was originally developed and tested between 1999 and 2001 at the University of California, Davis Combustion Laboratory, with funding from the California Energy Commission (CEC) [4]. Further funding from the DOE/NETL allowed CES to build a larger ($20MW_{th}$) gas generator for further testing between 2002 and 2003. Subsequent funding from CEC allowed CES to use this gas generator to fire a $5MW_e$ steam turbine generator at their Kimberlina power plant, near Bakersfield CA. The power plant fired by the gas generator went in to service in 2004 and first connected to the grid in 2005. Since that time, extensive testing has been done, including firing using a range of fuels from natural gas to simulated syngas, and carrying out long-term reliability runs. In the latest developments at the Kimberlina site, CES have developed, built and tested a $200MW_{th}$ gas generator and are currently installing it at the

power plant, driving a converted aero-derivative gas turbine. Below is a photograph of the 200MW_{th} gas generator prior to installation.

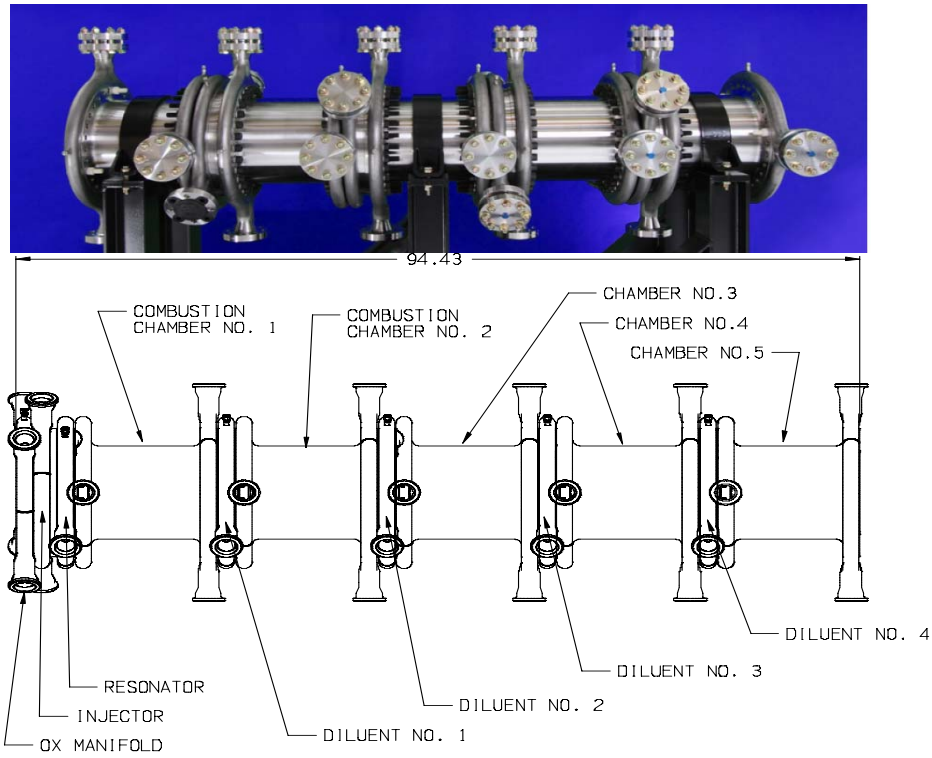


Figure 3.3: 200MW_{th} CES Burner

Application in IGSC

To obviate possible confusion, the “gas generator” is termed “CES burner” in IGSC application,

The CES burner works by supplying it with fuel and oxygen at high-pressure at near stoichiometric conditions and complete combustion takes place in the first zone of the burner. The combustor temperature is moderated by the injection of water directly through the burner to produce a steam/CO_2 working fluid (this is termed the “flue gas” in IGSC application) to be delivered to the Fired Expander.

In this first chamber, water is injected to maintain the combustion zone at 1650-1760ºC (3000-3200ºF), while in the downstream cool-down chambers, more water is injected to quench the steam/CO_2 “flue gas” to the required inlet temperature of the Fired Expander.

The burner itself consists of a number of photo-etched platelets carefully assembled into a block through which the reactants flow and mix. Combustion takes place on the surface of the block at the outlets of the holes.

The block is designed such that water is always present to prevent excessive temperatures occurring. A pilot flame is maintained through the diametric center.

Below are photographs of the combustor platelets being fabricated and a downstream water injector being tested.

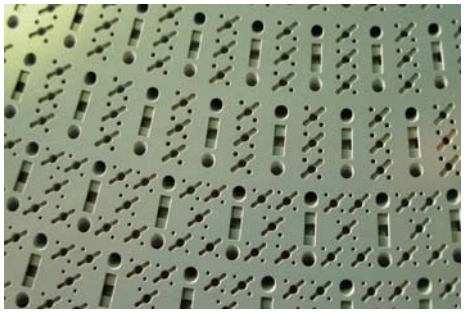


Figure 3.4: One of the Platelets

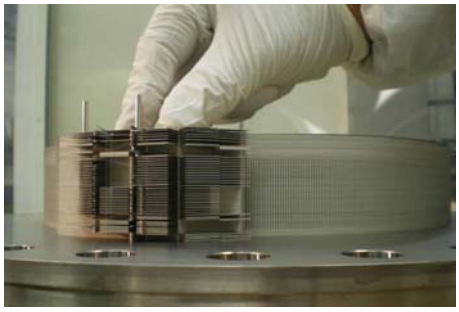


Figure 3.5: Assembly of the Burner Block

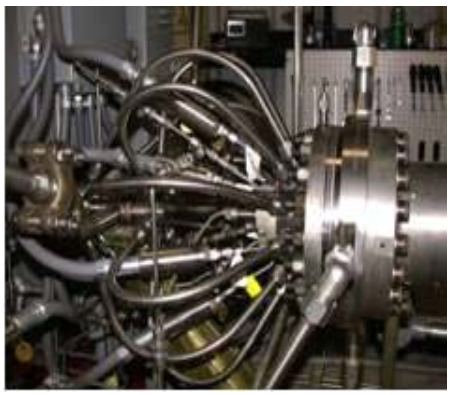


Figure 3.6: Burner and Feed System

Figure 3.7: Annular water injector under test

Overview of SGT5-4000F

The design concept for gas turbines with annular combustion builds on more than 50 years' experience with heavy-duty gas turbines of annular and silo combustion designs at Siemens. More than 400 gas turbine units have been installed and more than 10 Million operating hours have been accumulated.

The advanced technology or the SGT5-4000F gas turbine continues to satisfy the needs of the power generation marketplace for 50 Hz projects worldwide. This engine combines the efficient, proven design concepts with the addition of advanced combustion and cooling technologies and improved compressor construction.

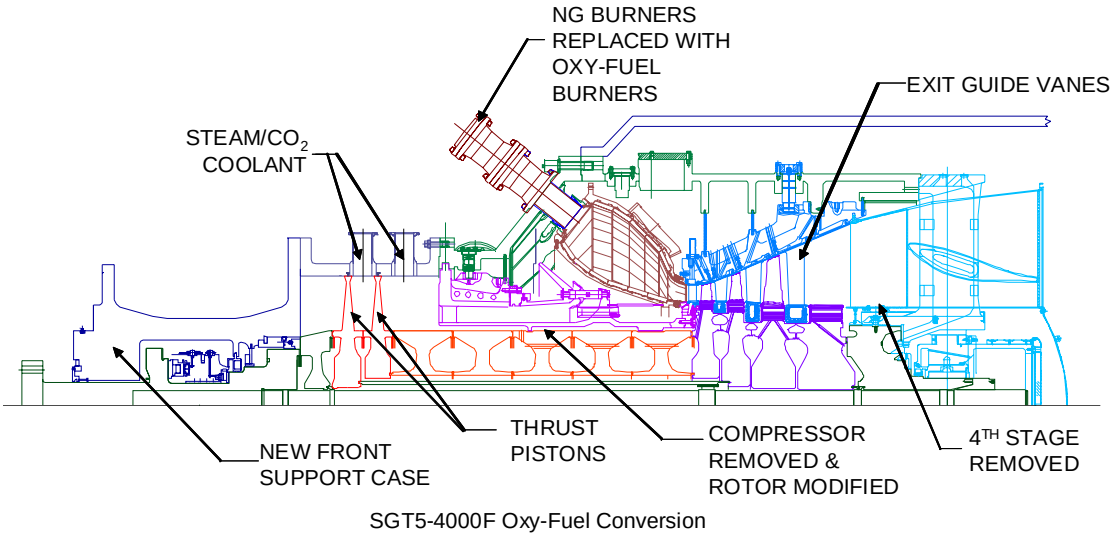
The proven SGT5-4000F is characterized by high performance, low power generating costs, long intervals between major inspections and an easy-to-service design. The first units were introduced in 1996 and have achieved over 3.5 million operating hours from 165 installed machines (with a further 80 machines on order or in construction). The lead unit has over 86,000 hours of operation, to date.

Optimized flow and cooling add up to the highest gas turbine efficiency levels for the most economical power generation in combined-cycle applications. Its state-of-the-art technology is based on proven design features.

Conversion of the SGT5-4000F Gas Turbine to Oxy-Fuel Firing

Below is a description of the work that will be done to convert the proven SGT5-4000F gas turbine for use in IGSC with oxy-fuel firing, using the CES burners.

The SGT5-4000F gas turbine was chosen as the basis for the fired expander due to its robust design, with a proven track record of good reliability and high availability, and its high performance, low generating costs, long intervals between major inspections and its easy-to-service design. The work required for the conversion can be done quickly, with the longest package of work being the environmental testing of the existing and revised materials. Siemens have every confidence that the design will succeed and that the lead-time to carry out the up-front design and development work is three years (rising to five years, depending on the programme of funding). The required modifications are shown in Figure 3.8.



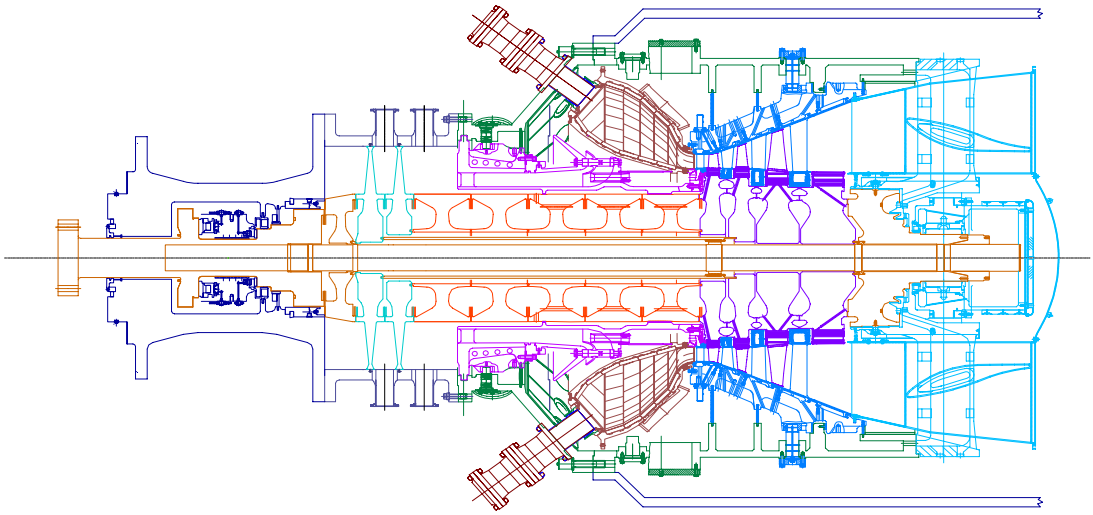


Figure 3.8: SGT5-4000F Gas Turbine Modification for IGSC

1. Remove compressor airfoils

   Remove the compressor airfoils from the machine. The resulting compressor flow path will be evaluated for windage characteristics and compressor disks and other systems will be removed as required. The rotor system will be adapted to accommodate the thrust balance piston as shown.

2. Inlet case fabrication

   The inlet case will be modified to accommodate the thrust balance piston, as shown.

3. High pressure gas path seal re-operation

   This re-op prevents leakage of coolant from the diffuser case back into the compressor end of the turbomachinery

4. Balance piston

   This rotating component is needed to provide a balance of forces on the rotor system in the absence of compression system loads. The thrust piston is stacked between compressor disks, and is sized to balance axial forces and sustained centrifugal loading.

5. Brush seal

   The thrust balance system concept requires two brush seal segments, one assembled into each half of the inlet case. This component has a typical arrangement with attachment rails integral to the brush backing plates. Alloy steel bristles are suitable for this low temperature application.

6. Integration of oxy-fuel burners

   The oxy-fuel burners make use of available manufacturing processes currently in use on either gas turbine combustion systems or those developed for Clean Energy System's-type primary combustion systems.

7. Turbine airfoil coating

   Use of the latest specifications for thermal barrier and oxidation protection.

8. Turbine exit guide vanes

   Analysis of the flow path shows that turbine exit de-swirl vanes are required. These assemblies will be designed as replacements for the existing row 4 vanes. These airfoils

can be cast or be machined and fabricated components in CM247 or similar nickel-based alloy.

9. Exhaust diffuser EGV modifications

   The turbine exhaust case will be modified with advanced materials and/or the addition of cooling methods to support increased exhaust temperatures and pressures relative to the base gas turbine design.

10. Condensate purge

    The requirement for external piping into each major engine cavity is anticipated in order to provide adequate purge gas flow to prevent corrosion by any residue acidic condensate. During normal operation of the plant, there will not be any acidic condensate collecting in the fired expander, due to the use of natural gas as the fuel during start up and shut down. But, to allow for emergency shut-downs, the condensate purge system will be included for enhanced reliability and availability. This system may also require ventilation holes to be drilled into various components or corrosion protective coatings applied at vulnerable locations.

Additional items to address as part of the final design:

- Pressure containment

  The mechanical configuration will also consider the containment of pressure within the engine. The IGSC cycle operates the hot expander at pressure levels that are about two times those of the typical gas turbine application. This requires the casings to be analyzed for capability to support the higher pressure level, be reinforced, or be used in conjunction with an additional pressure vessel to support the additional pressure loading.

- Shaft torque capability

  Extraction of shaft output power from the SGT5-4000F turbine will also be considered for the IGSC cycle. In the gas turbine installation, the turbine provides power to drive the compressor and the power take-off shaft. In the original gas turbine application, the SGT5-4000F rotor system turns at 3000rpm to produce about 280MW at 50Hz. In the IGSC cycle, the compressor is eliminated from the system and the turbine delivers over 600MW of power through the shaft at 3000rpm, for the utility case. The shaft in the turbine section

is designed to meet this torque, but the intermediate shaft, between the turbine and generator, will be redesigned for the increased torque capability.

- Materials and coatings

  The materials used in the SGT5-4000F turbine must be compatible with the oxy-fuel drive gas environment. The materials must be resistant to any oxidation and possible corrosive effects of the different environment. Adaptation of the gas turbine components to the oxy-fuel cycle may require some material substitutions and/or the application of oxidation and corrosion resistant coatings on both internal and external surfaces. The thermal barrier coatings that are utilized in the combustor and on the first four turbine airfoil rows (vane 1, blade 1, vane 2 and blade 2) must prove robust when operating with increased heat fluxes and temperature gradients and be resistant to other degradation mechanisms caused by the high steam content. The behaviour of these materials when in this new environment must be considered a risk at this time. This risk will be mitigated by performing appropriate environmental testing. This was not part of this project and will be performed prior to the first application. The work will be done in conjunction with Universities that have the capabilities to carry out such testing. Universities in the UK that have the relevant skills and equipment include Imperial College and Cranfield.

- Increased temperatures at third stage and in exhaust casing

  The hot expander operating with a working fluid of steam and CO_2 is expected to have a smaller temperature drop than the gas turbine operating with conventional products of combustion (fuel and air). To operate such an oxy-fuel turbine with the same inlet temperature as the gas turbine poses a risk and technical challenge to the components in the aft stage(s) of the turbine and in the turbine exhaust casing, because these areas will operate with an increased temperature. To address these concerns, additional conceptual design work will be carried out to verify the capability of components located in the last stage of the turbine, and to define the turbine exhaust materials and/or cooling needs.

3.8.2 Heat Recovery Steam Generator (HRSG)

The main function of the HRSG is to convert the bulk of the heat in the Fired Expander exhaust to high pressure superheated steam for feeding to the main condensing Steam Turbine. The HRSG also provides the reheat for the main Steam Turbine HP stage exhaust steam for the IP stage.

When considering the design philosophy of using commercially proven concepts and equipment, it appears appropriate to turn to the gasification and chemical industries using such waste heat pressurised boilers raising high pressure steam. This type of equipment is widely available especially from German designers and fabricators, and MAN has obtained the best possible advice in arriving at the final design.

Two 50% HRSG units are attached directly to the outlet flange of Fired Expander splitting and turning the exhaust flow upwards before entering the two parallel, vertical HRSG units.

Each HRSG is a “once through” steam generator design which is specially configured to ensure that its surface temperatures operate with a large margin above ADT under all operating conditions.

The HRSG system is configured to achieve “Load Following” by operating both the Fired Expander and the Main Steam Turbine at partial load. A typical arrangement of such an HRSG is shown below-

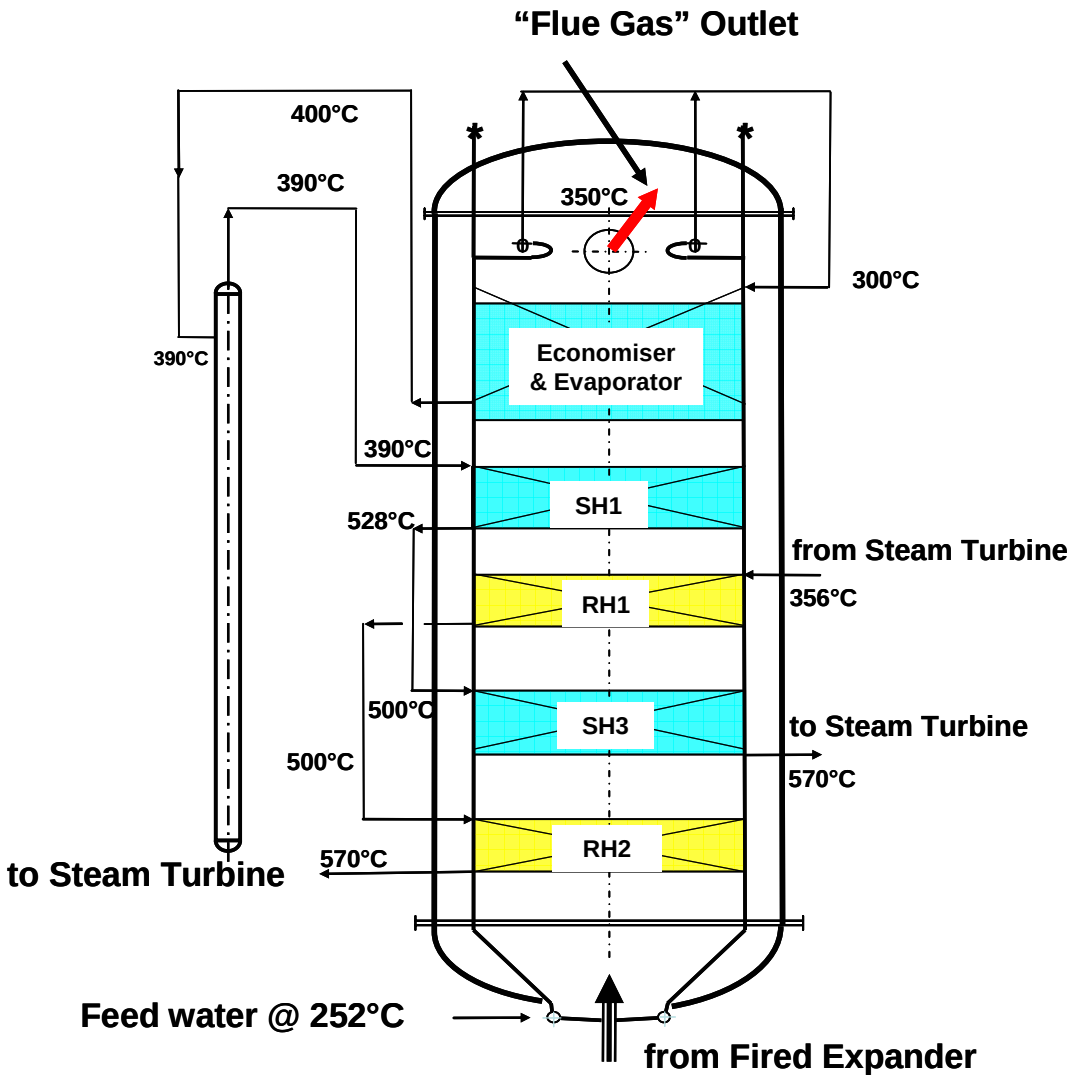


Figure 3.9 HRSG

3.8.3 CO_2 and Recycle Coolant Compressors

CO_2 Compressor

High pressure compression of the by-product CO_2 for long distance transmission for EOR and Storage purposes has been in commercial practice in USA and Canada for many years.

MAN supplied the three compressors for the world's biggest CCS from coal project at the Great Plains plant in North Dakota, US. The installation delivers >380 te/hr (~140 MMSCFD) of pure CO_2 into a 205 mile pipeline for delivery to the Canadian Weyburn EOR Project.

This quantity represents about 50% of the requirement of the IGSC Retrofit Case – however the Dakota scheme is compressing from near atmospheric pressure to 187-200 bar with specific suction volumes approx 10 times larger than IGSC.

For the Retrofit Case, MAN recommends 2 x 50% Compressors, each compressing 498 t/h CO_2 from 10 to 100 bar. These 4 stage compressor units have the same frame-size as those installed at the Great Plains plant in North Dakota.

Coolant Recycle Compressor

As discussed above, the Fired Expander requires a considerable quantity of cooling gas to be able to operate continuously at inlet temperatures in excess of 1000° C.

The steam/CO_2 mixture is taken downstream of the HRSG at ~11 bar abs 240°C and is compressed in an un-cooled two-casing centrifugal compressor. Temperature differentials (~90°C) across the two casings are kept to manageable limits, leading to a final discharge temperature >400°C. .

MAN would need to confirm compressor design, materials of construction, and compressor sealing during detailed design.

Note: The elevated temperature of the "flue gas" mixture delivered as coolant to the fired gas expander is considerably above ADT and WDT.

3.8.4 Steam Turbines

The Steam Turbine for all Cases is a conventional sub-critical conventional condensing turbine. There are three expansion stages for the Base, Utility, and Retrofit Case and an additional single condensing turbine for the Auxiliary Steam Turbine used in the Retrofit.

For the Utility Case, the requirement for a single condensing turbine in the order of 1,075 MW is considered impractical to build because of its size. However the 1,075 MW capacity could be achieved using two parallel machines, and for the purposes of the estimating exercise, two single shaft turbines each with three expansion stages each have been used.

The Retrofit Case is intended for application to an existing c500MW UK power station, and purely for the purposes of the exercise, a steam turbine at present operating in the Ferrybrid‘e’'C' 1995MW coal-fired power station currently owned by Scottish and Southern Energy plc. It was the first 2000MW power station in Europe and first supplied energy to the National Grid in 1966.

The station itself comprises four 500MW units, using 800 tonnes of coal and 218 million litres of coolant water per hour.

Ferrybrid‘e’'C' has had an original operating life of over 40 years.

Work has recently begun on a new FGD (Flue Gas Desulphurisation) plant servicing units 3 & 4 which is scheduled to be completed in 2008.

The following discusses the characteristics of the Utility and Retrofit Case steam turbines.

<u>Utility Case</u>

The turbine generators for the utility case are two lines of 570MW nominal output SST-6000 turbine series. Each turbine line consists of one single flow HP turbine, one double flow IP turbine, two or three double flow LP turbines and a water cooled generator.

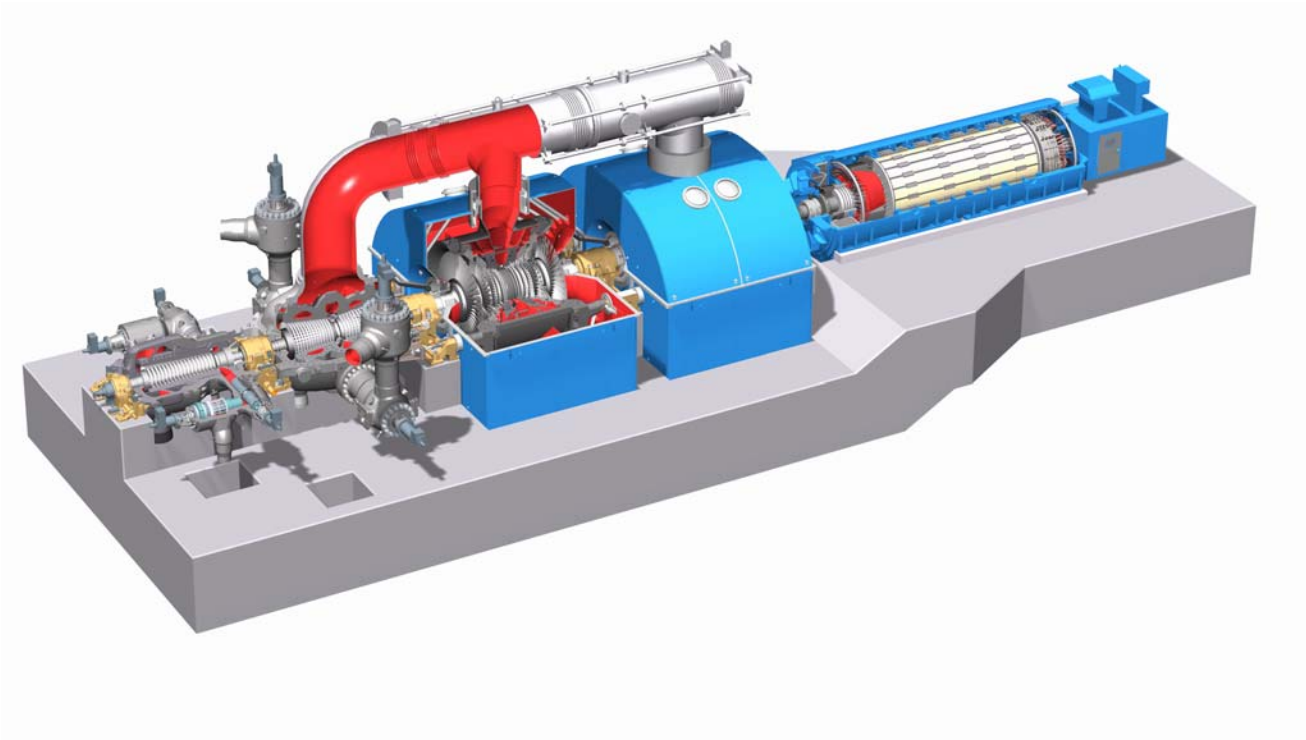


Figure 3.10: SST-6000 Series Steam Turbines

Retrofit Case

The work for the retrofit case is based on the Ferrybridge 'C' power station. The station was first commissioned in 1966, with 4 Parsons 500MW steam turbine generator units installed.

Figure 3.11: Parsons 500MW Steam Turbine Generator

The steam conditions from the heat recovery steam generators have been specified to match the existing steam turbines. The steam turbine generators and associated systems do not, therefore, require any significant repair or upgrade work as part of the overall zero emissions conversion. The option exists for the station owner to upgrade the steam turbines and generators for improved performance and life extension, as already carried out on Ferrybridge units 3 & 4.

The IGSC produces an additional supply of low pressure steam, which cannot be used in the original steam turbine. An auxiliary low pressure turbine generator would be installed to utilise this steam, producing an additional 300MW approximately. This low pressure turbine generator line would consist of two or three separate LP turbines, similar to the ones used for the utility case, with a hydrogen cooled generator.

3.9 Control Philosophy

In an Integrated Gasification Combined Cycle (IGCC) plant, the fossil fuel feedstock is partially oxidised (c40%) through gasification with oxygen, the thermal heat released is recovered and the product syngas is treated to make it suitable for firing in a gas turbine/steam turbine combined cycle arrangement to generate power. The c60% balance of oxygen for complete combustion is supplied by the combustion air drawn into the gas turbine. The hot exhaust of the gas turbine is then used to feed a boiler/steam turbine set through an HRSG to raise steam.

The Integrated Gasification Steam Cycle (IGSC) is similar to an IGCC in which partial oxidation with oxygen in a gasifier is followed by complete combustion and hot expansion to generate power. However the Fired Expander fed with the gasifier syngas uses oxygen and not air. The hot exhaust of the Fired Expander is also used to feed a boiler/steam turbine generator set through a steam raising HRSG.

Thus the IGSC cycle consists of:

- Syngas production (through partial oxidation/gasification)
- Combustion/expansion of the syngas to generate power
- Raising steam from the expander hot exhaust and using it in a condensing steam turbine
- Separation of the CO_2 from the steam/CO_2 “flue gas” by condensing the steam, and recovering the low grade heat as LP steam
- Final compression of the by-product CO_2 during which drying and any necessary sulphur removal is carried out before the CO_2 is sent to EOR or storage.

For the consideration of control issues, the plant may be more clearly depicted as follows:

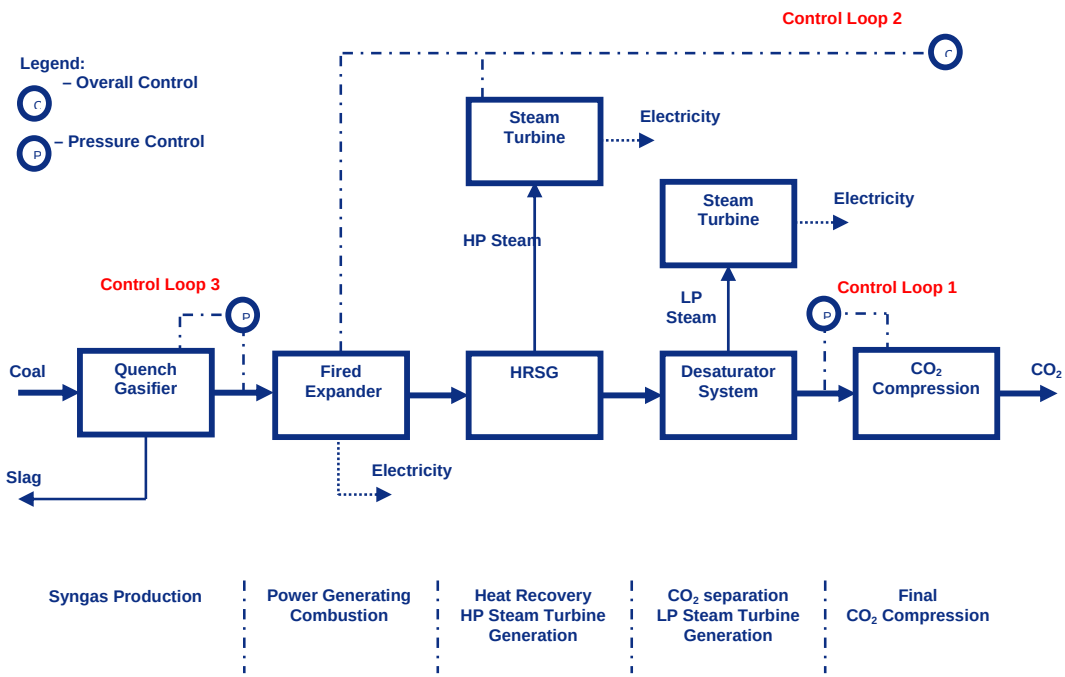


Figure 3.12: OVERALL CONTROL SYSTEM

The three primary control loops illustrated above are:

1 Back-End Control

This automatically controls back-end pressure through the extraction, capture, compression, and exporting of the CO_2 at a rate to balance production. This loop is independent of other controls and provides stability at the bottom of the cycle, especially for the steam condensing conditions in the Desaturator.

2 Output Control

Output control is effected through the inlet valves of the Steam Turbine coupled with a corresponding increase of the Fired Expander fuel rate to maintain a balance of available steam production to power output demand.

3 Fuel Supply Control

In order to maintain a consistent fuel supply, the rate of gasification will be controlled to maintain a constant pressure of clean syngas fuel for the Fired Expander. The recommended proportions of coal, oxygen and water fed to the gasifier will be provided by the gasification licensor together with a well proven control system incorporating the necessary safeguards to avoid hazardous conditions.

3.10 CO_2 Export

This section defines probable purity specifications of the by-product CO_2 in order for it to be suitable for EOR or long term storage, and discusses briefly how they can be met within the battery limits of the IGSC technology essentially for:

- Delivery Pressure
- Oxygen Content
- Nitrogen Content
- Acid Gas Content

In order to gain the maximum benefit from the captured CO_2, it is necessary to achieve purities that conform to its means of transportation and final use i.e. for Enhanced Oil Recovery (EOR) or for storage in deep geological structures beneath the North Sea such as depleted oil and gas fields or saline aquifers.

Chemical Purity Requirements

The chemical purity of CO_2 for EOR applications is tighter than the specification for just storage in a geological formation; however, future build out from the UK coastline of an interconnected pipeline infrastructure may require even more stringent specifications than are mooted at present In order to avoid any cross contamination.

Such precise specifications have not yet been universally agreed for the North Sea and data has been obtained from the USA where the practice of transporting CO_2 by pipeline for considerable distances for use in EOR has been in place for many years.

In the Permian Basin area of West Texas the following conditions apply to delivered CO_2 [5]:

- Product to contain at least ninety-five mole percent (95%) CO_2
- Water – shall not contain any free water and be less than 250 ppm in the vapour phase

- Hydrogen Sulphide - shall not contain more than twenty (20) parts per million, by weight, of hydrogen sulphide (one area allows up to 200 ppm).
- Total Sulphur - shall not contain more than thirty-five (35) parts per million, by weight, of total sulphur (one area allows up to 200 ppm).
- Nitrogen - shall not contain more than four mole percent (4%) of nitrogen.
- Hydrocarbons - shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed minus twenty degrees Fahrenheit (-30°C).
- Oxygen - shall not contain more than ten (10) parts per million, by weight, of oxygen.

Most of the water that comes out of the CES combustor is removed in the Desaturator and the remaining free water is removed in the knock out drums in the intercooler sections of the CO_2 compressor. However, the maximum solubility saturation limit of dissolved water in carbon dioxide for the operating range of pressures and temperatures from the compressor and after cooler are 900 to 1500 ppm. A molecular sieve will be incorporated in the plant to remove this level of moisture down to a required level for the pipeline operator.

The moisture specification for North Sea pipelines may be tighter than the specification for onshore pipelines because the pipeline fluid will cool to the constant sub sea temperature of 4 deg C. At these temperatures, CO_2 hydrates have been known to form so levels of moisture to avoid corrosion such as 250 ppm may not be low enough to assure no formation of CO_2 hydrates. Preliminarily, at least one potential pipeline operator is looking at less than 50 ppm of water in the product CO_2 and this should be achievable from the proposed equipment.

The above specifications for hydrogen sulphide, total sulphur, nitrogen, hydrocarbons and oxygen are directed by the oil field operators and their desire not to contaminate their oil fields. The less restricted specification for hydrogen sulphide and total sulphur referenced reflects the requirements of an oil region that already has hydrogen sulphide in the oil.

The IGSC technology will be capable of meeting each of these specifications. By requiring the purity of oxygen to be greater than 96% oxygen, the remaining nitrogen in the presence of CO_2

will be less than the four mole percent (4%) of the product stream and the CO_2 will make up at least 95% of the product stream.

Hydrogen and hydrocarbons will be absent, and as the CES combustor is capable of delivering near stoichiometric combustion of the syngas with as little as 0.5% excess oxygen, there will very little residual oxygen in the product stream.

A novel system for removing even the last traces of oxygen at the same time as removing all sulphur as sulphuric acid is discussed in Section 9.4.1 “Further R&D”.

Pressure and Temperature Requirements

In addition to chemical purity specifications, a delivery pressure and temperature must be established which caters for the local conditions. In the UK, the Health & Safety Inspectorate have proposed that onshore CO_2 lines should not be run as supercritical CO_2 lines (greater than 73 bar and 31 deg C). On the other hand it is critical to run the CO_2 lines above 90 bar to avoid possible cavitation within booster pumps that will be located near the pipeline landfall locations. Therefore, the CO_2 must be cooled below 31 deg C to assure the product is in the liquid and not supercritical phase at the proposed operating pressures of 100-110 bar at the power plant fence.

Pipeline Systems

At least four parties in the UK have looked at installing new CO_2 pipelines or converting existing gas pipelines to CO_2:

- Yorkshire Forward, the regional development agency whose remit includes the Humberside Region, has worked with a number of the area’s generators to investigate the installation of a gathering system and delivery line to depleted gas fields in the Southern North Sea
- Centrica and Progressive Energy have established the CO_2 Transport System (COOTS Ltd) to install a pipeline from Teesside to the Central North Sea for storage and EOR purposes
- BP has considered converting the Miller gas line to a CO_2 line and

- National Grid Transco proposed in its application for the current BERR CCS competition to offer one of their gas lines from Southern Scotland to St. Fergus as a converted CO_2 line.

Lines are also being proposed from Rotterdam, Northern Germany, Denmark and Norway and there is the potential that some day there will be an interconnected infrastructure to deliver large quantities of CO_2 to oil fields and geological structures for storage.

Such an interconnected system will demand that all the CO_2 conforms to the most onerous specification required for the CO_2. That is, that required for use in EOR. Therefore, captured CO_2 should be capable of meeting the more restricted specifications described above for future use in EOR applications.

It should be noted that there will be two types of sourced CO_2. That captured pre-combustion and that captured post-combustion.

- The pre-combustion CO_2 will have been captured from a reformed or gasified syngas in reducing conditions, and hence possibly contain hydrogen and traces of hydrocarbon, mainly methane. This type of captured CO_2 may be regarded as a "scavenger" of any possible traces of oxygen or oxides within the pipeline system.

- Post-combustion CO_2 such as what would be captured from oxyfuel processes and flue gas scrubbing contain oxygen and the operator of the CO_2 pipeline network may need to carefully consider the compatibility of mixing these two types of captured CO_2.

3.11 Safety, Health & Environmental Issues

3.11.1 Safety

IGSC operation is very similar to that of an IGCC, but it possesses less hazards.

In IGSC, gasification is carried out by partial oxidation of the coal feedstock using pure oxygen at high elevated pressure and temperature as in IGCC gasification and therefore it is normal industry practice. Attendant with the use of oxygen is the potential risk of an explosion. Therefore extreme care is necessary in the way oxygen is supplied to the gasifier burner and

high integrity piping is provided. Adequate bonding is used to eliminate any risk of static generation.

Syngas contains mainly H_2, CO, CO_2 together with steam evaporated in the quench system which is all fed to the Fired Expander. Any leak of this gas could create fire, toxicity (from CO) and asphyxiation (from CO_2) hazards especially in confined areas.

However, the risk of fire will be mitigated by the high water content of the syngas (>50%). Nevertheless, any release of this gas will be at high pressure and temperature and jet fire is likely. This should be taken into account and adequate separation distances allowed for in the plant layout. Gas monitoring should be provided to detect any leaks and warn operating staff of the danger and to take corrective action.

The Fired Expander is also supplied with oxygen to the 24 CES burners and hence great care is necessary in the design of the oxygen supply piping and its protection. It is important to ensure that vibration from the rotating machinery is not transmitted to this piping and adequate anti vibration measures such as rubber matting and anti vibration mounts at supports should be provided.

However both the gasification plant and the CES burners have many years of safe operational experience using systems designed and optimised for safety by their licensors. This experience will be available and will be employed in what is essentially a standard feed system.

High temperature “flue gas” exits the Fired Expander and is fed to the two HRSG units. This piping requires to be refractory lined and is subject to differential expansion between the single Fired Expander and the two HRSGs. There is a potential for failure of this piping if it is not properly designed to account for such differentials and correct material and refractory selection to cater for the high temperature.

Very high pressure, 375 bar, BFW and steam systems are utilised. Accidents have occurred in the wider industry whenever personnel had not taken adequate precautions thinking it is just water and steam. It is essential that double block and bleed arrangements are provided for the secure isolation of such high pressure piping to protect maintenance personnel.

The CO_2 compression and drying area has the potential danger of leakage of CO_2 which is a heavier-than-air asphyxiant. Therefore low oxygen monitoring should be provided in this area.

Wet CO_2 is corrosive and proper material selection to combat it is essential to avoid leaks resulting from such corrosion.

Sulphur compounds present in the coal will result in SO_2 which flows through the gasification system, Fired Expander, HRSG, LP boilers and the Desaturators. Acid gas condensation occurs in the LP boilers and suitable corrosion resistant material has to be used for their construction. The SO_2 discharges with the CO_2 and it can be separated in the compression and drying process to form sulphuric acid for sale as a by-product or for conversion to gypsum.

3.11.2 Health

In the coal gasification process, large quantities of raw material coal are handled and in doing so a significant amount of fine coal dust may be formed. This poses a threat to the health of not only the workers but also of any visitors to these areas. Exposure to coal dust can lead to breathing difficulties and prolonged exposure can cause pneumoconiosis. Therefore it is important to provide adequate vacuum cleaning facilities such that all dust is sucked away and captured in bag filters for safe disposal. Good house keeping is necessary and personnel working in this area should wear breathing masks as a precautionary measure.

Depending on the level of impurities present in the coal, syngas formed by coal combustion can contain H_2S, COS, HCN, HCl, Hg, As etc. along with the main gases H_2, CO, CO_2. The cyanides and H_2S are poisonous gases and CO is toxic. Good engineering practices need to be followed in the design of equipment and piping to minimise the risk of leakage. At the same time, gas monitoring has to be provided to warn operators of the danger if a leak is to occur. All site staff shall carry H_2S monitors to alert them to any toxic leaks and for their cumulative exposure to such leaks. Heavy metals present in the coal are trapped in the non-leachable slag from the quench gasifier system and pose no health risk.

3.11.3 Environment

Existing fossil fuel based power plants emit significant amounts of CO_2 to the atmosphere which is causing concern about its probable impact on global warming. IGCC and flue gas scrubbing technologies can remove up to 90% of the CO_2 generated in their processes.

There are not many coal fed IGCC plants that have been in long term commercial operation, and none incorporate CCS. Flue gas scrubbing of CO_2 is still in development for power plant application.

IGSC offers the most environmentally friendly scheme for power generation. It achieves 100% CO_2 capture post combustion and which can then be used for enhanced oil recovery or sent to storage in a disused gas or oil field. There is no chimney stack and thus there are no pollutant discharges to atmosphere.

The majority of the water is recycled within the process but the IGSC produces excess water and this is discharged as a purge stream from the Desaturator circuit. After degassing this water, which is at 80°C, it can be used for central heating systems in the vicinity of the plant. This also increases the operating efficiency of the IGSC process.

The only solids discharge from the plant is that of the non-leachable slag resulting from gasification and this can be used in the construction of roads.

4.0 PERFORMANCE DATA

4.1 Overall Performance

	UNITS	UTILITY	RETROFIT
EXCLUDING ASU			
Net Power	MWh/h	1510	1088
Efficiency	% net LCV	44.5	40.7
Investment Cost	$/kW installed	2,543	1,801
Coal Input (ROM)	te/hr	496	426
Oxygen Input	te/day	24,679*	19,713**
CO_2 Exported	te/day	28,758	23,152
Return on Investment (ROI)	% per annum	-	14
Internal Rate of Return (IRR)	%	-	11.9
Loan Payback Time	Years	-	15

	UNITS	UTILITY	RETROFIT
INCLUDING ASU			
Net Power	MWh/h	1,177	811
Efficiency	% net LCV	34.1	27.9
Investment Cost	$/kW installed	4,113	4,235
Coal Input (ROM)	te/hr	496	426
Oxygen Input	te/day	24,679*	19,713**
CO_2 Exported	te/day	28,758	23,152
Return on Investment (ROI)	% per annum	-	10
Internal Rate of Return (IRR)	%	-	8.6
Loan Payback Time	Years	-	15

* Oxygen feed is at 95% purity

** Oxygen feed is at 99.5% purity

4.2 Mass Balances.

4.2.1 Utility Case Mass Balance

This mass balance should be read in conjunction with the Process Flow Diagrams (PFD) for the utility case. The stream numbers in the mass balance refer to those shown on the PFDs, see appendix A1.

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

MATERIAL BALANCE

Document No.: **60-8766-00/P.03/2002**

Project No.: 60-8766-00 Plant: IGSC

Client: DTI Location: Hatfield

Case: Utility Case UK

STREAM NUMBER		1		2		3		4		5		6	
STREAM NAME		Total Coal Feed		Total Oxygen Feed to Gasifiers		Oxygen Feed per Gasifier		Raw Syngas per Gasifier		Hot Water Recycle per Gasifier		Total Syngas Feed to Fired Expander	
COMPONENT	MW	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00	4055.49	37.96	0.00	0.00	16221.94	37.96
Nitrogen	28.013	0.00	0.00	262.49	2.00	65.62	2.00	119.59	1.12	0.03	0.24	478.35	1.12
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00	4579.28	42.86	0.00	0.00	18317.10	42.86
Carbon Dioxide	44.010	0.00	0.00	0.00	0.00	0.00	0.00	1745.73	16.34	10.13	85.97	6982.90	16.34
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	10.66	0.10	0.00	0.00	42.66	0.10
Argon	39.948	0.00	0.00	393.74	3.00	98.44	3.00	98.48	0.92	0.04	0.35	393.90	0.92
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	70.64	0.66	0.00	0.00	282.58	0.66
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00	2.83	0.03	0.00	0.00	11.34	0.03
Oxygen	31.999	0.00	0.00	12468.52	95.00	3117.13	95.00	0.00	0.00	0.00	0.04	0.02	0.00
Sulphur Dioxide	64.065	0.00	0.00	0.00	0.00	0.00	0.00	1.58	0.01	1.58	13.40	6.31	0.01
Sulphur	32.070	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	(kg/hr)	496044.00											
Temperature	°C	56		40		40		223		160		223	
Pressure	bara	62.00		56.10		56.10		39.08		43.10		39.08	
Total Dry Molar Flow	(kg.mol/h)	-		13124.76		3281.19		10684.27		11.79		42737.10	
Water (kg.mol/h)	18.015	0.00		0.00		0.00		21102.05		22552.39		84408.19	
TOTAL WET	(kg.mol/h)	-		13124.76		3281.19		31786.32		22564.18		127145.29	
Total Mass Flow (kg/h)		496044		422060		105515		603598		406889		2414394	
Molecular Weight				32.16		32.16		18.99		18.03		18.99	

Notes :

There will be trace amounts of chlorides and ammonia within the streams which are not shown in the mass balance.

Issue:	A	Date		Date		Date		Date		Date
Description:	For Report									
Made By:	EM	22-Sep-08								
Checked:	MK	23-Sep-08								
Approved:	MK	23-Sep-08								

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

MATERIAL BALANCE

Document No.: **60-8766-00/P.03/2002**

Project No.: 60-8766-00 Plant: IGSC

Client: DTI Location: Hatfield UK

Case: Utility Case

STREAM NUMBER		7		8		9		10		11		12	
STREAM NAME		Oxygen Feed to Fired Expander		Water Recycle to Fired Expander		Total Hot Flue Gas		Hot Flue Gas per HRSG Train		Flue Gas Feed to LP Boiler per HRSG Train		Flue Gas Flow from each LP Boiler	
COMPONENT	MW	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrogen	28.013	377.06	2.00	0.05	0.24	1075.13	3.16	537.57	3.16	436.39	3.16	109.10	3.16
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	44.010	0.00	0.00	17.69	85.97	31261.02	91.92	15630.51	91.92	12688.66	91.92	3172.17	91.92
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Argon	39.948	565.59	3.00	0.07	0.35	1182.31	3.48	591.15	3.48	479.89	3.48	119.97	3.48
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxygen	31.999	17910.49	95.00	0.01	0.04	109.80	0.32	54.90	0.32	44.57	0.32	11.14	0.32
Sulphur Dioxide	64.065	0.00	0.00	2.76	13.40	378.86	1.11	189.43	1.11	153.78	1.11	38.44	1.11
Sulphur	32.070	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	(kg/hr)												
Temperature	°C	40		160		963		963		237		237	
Pressure	bara	45.10		43.10		12.00		12.00		11.00		11.00	
Total Dry Molar Flow	(kg.mol/h)	18853.15		20.57		34007.12		17003.56		13803.28		3450.82	
Water (kg.mol/h)	18.015	0.00		39353.68		172948.00		86474.00		70198.50		17549.63	
TOTAL WET	(kg.mol/h)	18853.15		39374.25		206955.12		103477.56		84001.78		21000.45	
Total Mass Flow (kg/h)		606271		710017		4596637		2298318		1865746		466437	
Molecular Weight		32.16		18.03		22.21		22.21		22.21		22.21	

Notes :

There will be trace amounts of chlorides and ammonia within the streams which are not shown in the mass balance.

Issue:	A	Date		Date		Date		Date		Date
Description:	For Report									
Made By:	EM	22-Sep-08								
Checked:	MK	23-Sep-08								
Approved:	MK	23-Sep-08								

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

MATERIAL BALANCE

Document No.: **60-8766-00/P.03/2002**

Project No.: 60-8766-00 Plant: IGSC

Client: DTI Location: Hatfield UK

Case: Utility Case

STREAM NUMBER		13		14		15		16		17		18	
STREAM NAME		HP BFW Flow per HRSG Train		CO2 flow per Desaturator		CO2 Flow per HRSG Train		Total CO2 Flow		Water Recycle per Desaturator		Hot Water Recycle per HRSG Train	
COMPONENT	MW	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.06	0.00	0.11	0.00	0.23	0.00	0.00	0.00	0.00	0.00
Nitrogen	28.013	0.00	0.00	218.15	3.17	436.29	3.17	872.58	3.17	0.05	0.22	0.09	0.22
Carbon Monoxide	28.010	0.00	0.00	0.05	0.00	0.11	0.00	0.22	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	44.010	0.00	0.00	6326.49	91.98	12652.99	91.98	25305.97	91.98	16.88	82.29	33.77	82.25
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Argon	39.948	0.00	0.00	239.87	3.49	479.75	3.49	959.49	3.49	0.07	0.33	0.13	0.33
Hydrogen Sulphide	34.082	0.00	0.00	0.02	0.00	0.04	0.00	0.08	0.00	0.00	0.00	0.00	0.00
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxygen	31.999	0.00	0.00	22.28	0.32	44.55	0.32	89.10	0.32	0.01	0.03	0.01	0.03
Sulphur Dioxide	64.065	0.00	0.00	71.41	1.04	142.83	1.04	285.65	1.04	3.51	17.12	7.05	17.16
Sulphur	32.070	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	(kg/hr)												
Temperature	°C	150		47		47		47		151		152	
Pressure	bara	160.00		10.10		10.10		10.10		10.10		44.00	
Total Dry Molar Flow	(kg.mol/h)	0.00		6878.33		13756.66		27513.33		20.52		41.06	
Water (kg.mol/h)	18.015	47182.17		78.86		157.72		315.45		32378.25		169960.00	
TOTAL WET	(kg.mol/h)	47182.17		6957.19		13914.39		27828.78		32398.77		170001.06	
Total Mass Flow (kg/h)		850000		300832		601664		1203328		584376		3066306	
Molecular Weight		18.02		43.24		43.24		43.24		18.04		18.04	

Notes :

There will be trace amounts of chlorides and ammonia within the streams which are not shown in the mass balance.

Issue:	A	Date		Date		Date		Date		Date
Description:	For Report									
Made By:	EM	22-Sep-08								
Checked:	MK	23-Sep-08								
Approved:	MK	23-Sep-08								

4.2.2 Retrofit Case Mass Balance

This mass balance should be read in conjunction with the Process Flow Diagrams (PFD) for the retrofit case. The stream numbers in the mass balance refer to those shown on the PFDs, see Appendix A2.

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

MATERIAL BALANCE

Document No.: **60-8766-00/P.03/3002**

Project No.: 60-8766-00 Plant: IGSC

Client: DTI Location: Hatfield

Case: Retrofit Case UK

STREAM NUMBER		1		2		3		4		5		6	
STREAM NAME		Total Coal Feed		Total Oxygen Feed to Gasifiers		Oxygen Feed per Gasifier		Raw Syngas per Gasifier		Hot Water Recycle per Gasifier		Total Syngas Feed to Fired Expander	
COMPONENT	MW	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00	3425.56	38.56	0.00	0.00	13702.22	38.56
Nitrogen	28.013	0.00	0.00	21.11	0.20	5.28	0.20	50.73	0.57	0.02	0.25	202.91	0.57
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00	3865.65	43.51	0.00	0.00	15462.60	43.51
Carbon Dioxide	44.010	0.00	0.00	0.00	0.00	0.00	0.00	1467.14	16.51	8.12	86.47	5868.55	16.51
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	4.48	0.05	0.00	0.00	17.91	0.05
Argon	39.948	0.00	0.00	31.66	0.30	7.92	0.30	7.95	0.09	0.03	0.36	31.80	0.09
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	60.79	0.68	0.00	0.00	243.18	0.68
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00	1.19	0.01	0.00	0.00	4.75	0.01
Oxygen	31.999	0.00	0.00	10501.49	99.50	2625.37	99.50	0.00	0.00	0.00	0.04	0.01	0.00
Sulphur Dioxide	64.065	0.00	0.00	0.00	0.00	0.00	0.00	1.21	0.01	1.21	12.89	4.84	0.01
Sulphur	32.070	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	(kg/hr)	426267.00											
Temperature	°C	56		40		40		223		160		223	
Pressure	bara	62.00		56.10		56.10		39.08		43.10		39.08	
Total Dry Molar Flow	(kg.mol/h)	-		10554.26		2638.57		8884.69		9.39		35538.76	
Water (kg.mol/h)	18.015	0.00		0.00		0.00		17819.74		18938.09		71278.94	
TOTAL WET	(kg.mol/h)	-		10554.26		2638.57		26704.43		18947.48		106817.70	
Total Mass Flow (kg/h)		426267		337891		84473		504838		341653		2019350	
Molecular Weight				32.01		32.01		18.90		18.03		18.90	

Notes :

There will be trace amounts of chlorides and ammonia within the streams which are not shown in the mass balance.

Issue:	A	Date		Date		Date		Date		Date
Description:	For Report									
Made By:	EM	23-Sep-08								
Checked:	MK	23-Sep-08								
Approved:	MK	23-Sep-08								

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

MATERIAL BALANCE

Document No.: **60-8766-00/P.03/3002**

Project No.: 60-8766-00 Plant: IGSC

Client: DTI Location: Hatfield

Case: Retrofit Case UK

STREAM NUMBER		7		8		9		10		11		12	
STREAM NAME		Oxygen Feed to Fired Expander		Water Recycle to Fired Expander		Total Hot Flue Gas		Hot Flue Gas per HRSG Train		Flue Gas Feed to LP Boiler per HRSG Train		Flue Gas Flow from each LP Boiler	
COMPONENT	MW	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nitrogen	28.013	30.20	0.20	0.05	0.25	290.86	1.13	145.43	1.13	123.80	1.13	30.95	1.13
Carbon Monoxide	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	44.010	0.00	0.00	17.37	86.47	25107.13	97.29	12553.57	97.29	10686.14	97.29	2671.53	97.29
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Argon	39.948	45.31	0.30	0.07	0.36	90.67	0.35	45.33	0.35	38.59	0.35	9.65	0.35
Hydrogen Sulphide	34.082	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxygen	31.999	15026.75	99.50	0.01	0.04	17.64	0.07	8.82	0.07	7.51	0.07	1.88	0.07
Sulphur Dioxide	64.065	0.00	0.00	2.59	12.89	299.92	1.16	149.96	1.16	127.65	1.16	31.91	1.16
Sulphur	32.070	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	(kg/hr)												
Temperature	°C	40		160		965		965		240		240	
Pressure	bara	45.10		43.10		12.00		12.00		11.00		11.00	
Total Dry Molar Flow	(kg.mol/h)	15102.26		20.09		25806.23		12903.11		10983.69		2745.92	
Water (kg.mol/h)	18.015	0.00		40505.82		147792.00		73896.00		62903.50		15725.88	
TOTAL WET	(kg.mol/h)	15102.26		40525.91		173598.23		86799.11		73887.19		18471.80	
Total Mass Flow (kg/h)		483494		730747		3799286		1899643		1617059		404265	
Molecular Weight		32.01		18.03		21.89		21.89		21.89		21.89	

Notes :

There will be trace amounts of chlorides and ammonia within the streams which are not shown in the mass balance.

Issue:	A	Date		Date		Date		Date		Date
Description:	For Report									
Made By:	EM	23-Sep-08								
Checked:	MK	23-Sep-08								
Approved:	MK	23-Sep-08								

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

MATERIAL BALANCE

Document No.: **60-8766-00/P.03/3002**

Project No.: 60-8766-00 Plant: IGSC

Client: DTI Location: Hatfield

Case: Retrofit Case UK

STREAM NUMBER		13		14		15		16		17		18	
STREAM NAME		HP BFW Flow per HRSG Train		CO2 flow per Desaturator		CO2 Flow per HRSG Train		Total CO2 Flow		Water Recycle per Desaturator		Hot Water Recycle per HRSG Train	
COMPONENT	MW	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)	kg.mol/h	mol% (dry)
Hydrogen	2.016	0.00	0.00	0.03	0.00	0.07	0.00	0.13	0.00	0.00	0.00	0.00	0.00
Nitrogen	28.013	0.00	0.00	61.89	1.13	123.77	1.13	247.54	1.13	0.01	0.09	0.02	0.09
Carbon Monoxide	28.010	0.00	0.00	0.03	0.00	0.06	0.00	0.11	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	44.010	0.00	0.00	5330.08	97.32	10660.17	97.32	21320.33	97.32	12.52	87.68	25.03	87.64
Methane	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Argon	39.948	0.00	0.00	19.29	0.35	38.58	0.35	77.16	0.35	0.00	0.03	0.01	0.03
Hydrogen Sulphide	34.082	0.00	0.00	0.02	0.00	0.05	0.00	0.10	0.00	0.00	0.00	0.00	0.00
Carbonyl Sulphide	60.076	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oxygen	31.999	0.00	0.00	3.75	0.07	7.51	0.07	15.01	0.07	0.00	0.01	0.00	0.01
Sulphur Dioxide	64.065	0.00	0.00	61.89	1.13	123.78	1.13	247.55	1.13	1.74	12.19	3.49	12.23
Sulphur	32.070	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal	(kg/hr)												
Temperature	°C	252		67		67		67		157		158	
Pressure	bara	160.00		10.10		10.10		10.10		10.10		44.00	
Total Dry Molar Flow	(kg.mol/h)	0.00		5476.98		10953.97		21907.94		14.27		28.56	
Water (kg.mol/h)	18.015	40489.63		169.20		338.40		676.79		29065.00		58130.00	
TOTAL WET	(kg.mol/h)	40489.63		5646.18		11292.37		22584.73		29079.27		58158.56	
Total Mass Flow (kg/h)		729432		244215		488430		976859		524340		1048679	
Molecular Weight		18.02		43.25		43.25		43.25		18.03		18.03	

Notes :

There will be trace amounts of chlorides and ammonia within the streams which are not shown in the mass balance.

Issue:	A	Date		Date		Date		Date		Date
Description:	For Report									
Made By:	EM	23-Sep-08								
Checked:	MK	23-Sep-08								
Approved:	MK	23-Sep-08								

–

5.0 UTILITIES AND OFFSITES

The utility systems associated with the IGSC plant are listed below.

- Raw water treating system.
- Cooling water
- Demineralised water.
- Process water.
- Boiler feed water.
- Steam/condensate.
- Power
- Natural Gas
- Oxygen
- Nitrogen
- Firewater
- Potable water
- Waste water treatment
- Electrical switchgear and distribution
- Amenity Buildings – Control building, Switch rooms, Admin Building, Workshop etc.

Descriptions of these systems are given in the following sections.

5.1 Water Treatment Plants

The raw water supply is taken from an adjacent fresh water source such as a canal. Typical canal water supply data has been utilised in developing the water treatment requirements to supply the different qualities of water to the plant.

In the water treatment plant (WTP) raw water is drawn from the canal chlorinated and screened. It is then split into two streams, one of which is fed to multimedia filters, the other to micro-membrane filters. The multimedia filter product is suitable for use as cooling water part of which is satisfied with recycled waste water from the waste water treatment plant. Further treatment to boiler feed water quality comprises, reverse osmosis (RO), degassing and mixed bed ion exchange.

Low grade heat from the desaturator circuit is recovered by heating the demineralised water and feeding part of it to the LP boilers to raise LP steam and the rest pumped to high pressure to feed the HRSG via the BFW heater. This ensures BFW fed to HRSG is always above the ADT.

The waste water treatment plant (WWTP) removes impurities from the waste stream and provides acceptable quality water for re-use as cooling water for the plant, thereby reducing the amount of raw canal water required, minimising the water treatment plant equipment required and minimising the liquid discharge to waste.

The waste water from the gasifier is saline and is treated to remove organic impurities within the consent limits for solids, BOD, COD heavy metals etc. before discharge to an estuary or the sea. Various boiler blowdowns and the desaturator purge water are recovered to the BFW treatment plant inlet. There is an ammonia stripper to remove any ammonia with overheads return to the gasifier circuit. Then bottoms pH is adjusted and sent to the WWTP. A low salinity effluent stream is discharged to the canal.

Water balances for the plant are presented below.

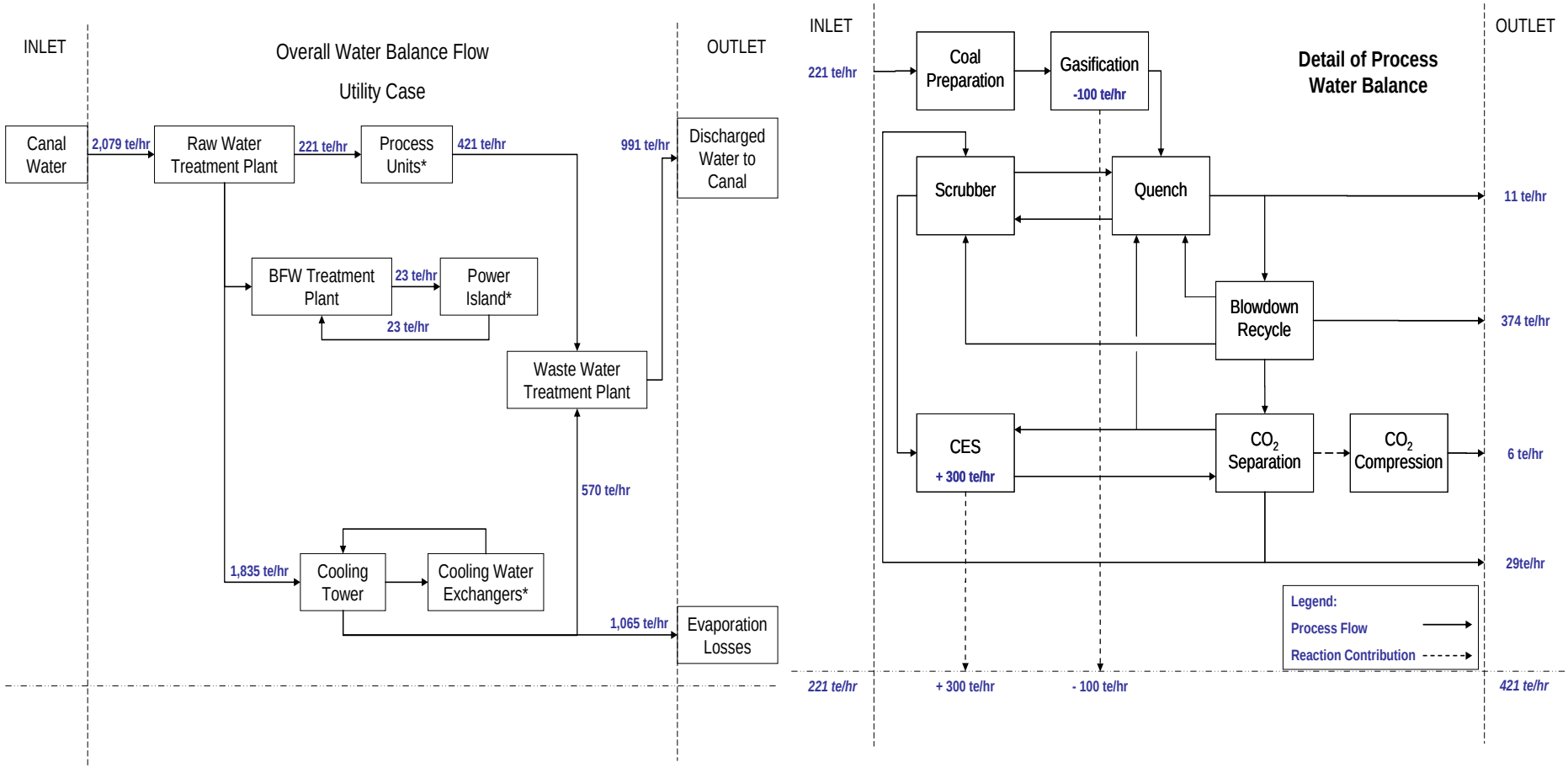


Figure 4.1: Overall Water Balances

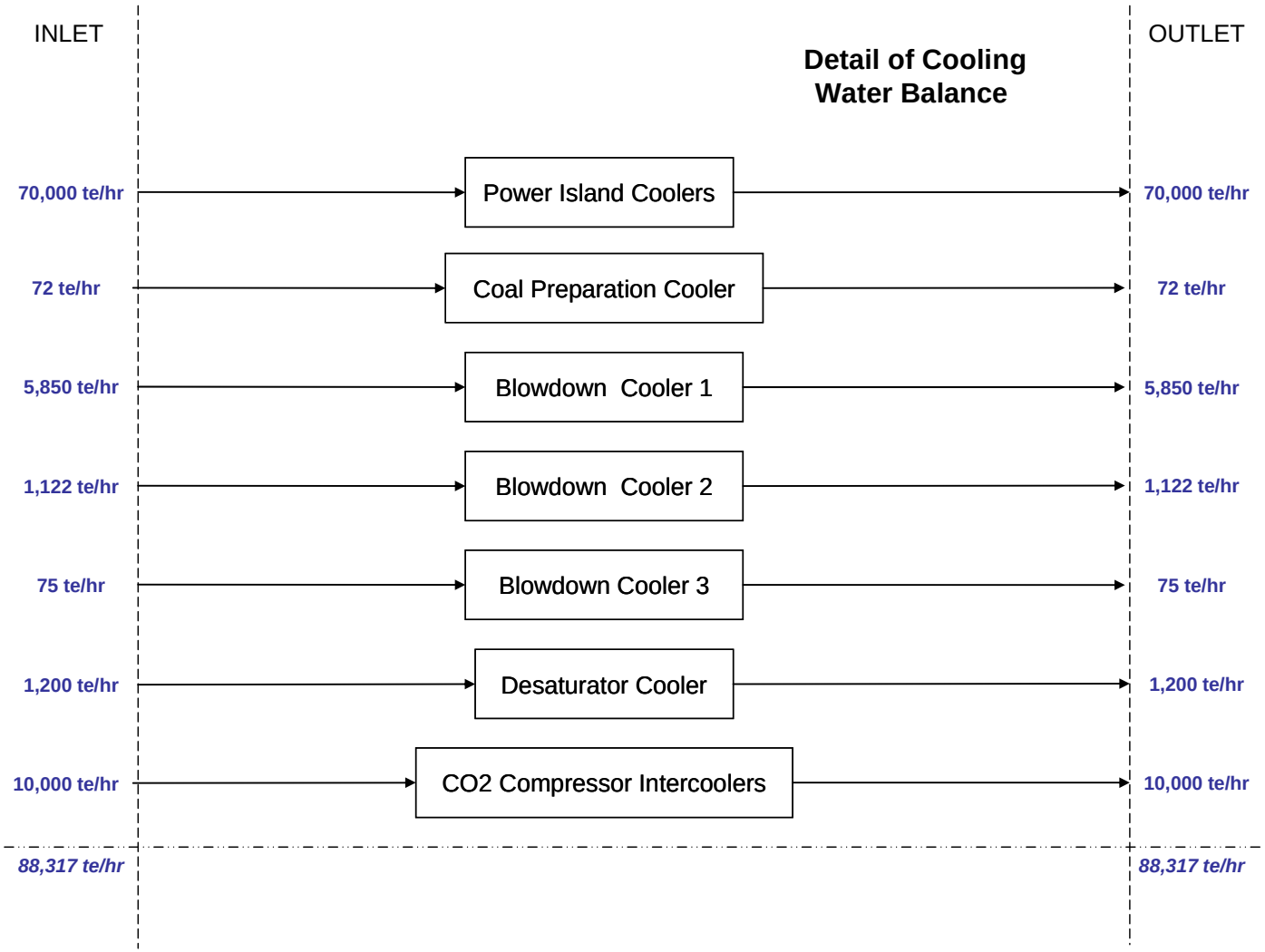


Figure 4.2: Cooling Water Balance Detail

5.2 Steam Systems

The heat of combustion from the fired expander exhaust is routed through an HRSG to generate HP steam that is fed to a steam turbine to generate power. HRSG also provides IP reheat. The steam generated is also utilised to provide heat for superheating the syngas before the expander.

Three levels of steam generation is involved in the IGSC plant, viz. HP steam at 136 bar(g), IP steam at 40 bar(g) and LP steam at 5 bar(g.

5.3 Electrical Distribution

Power is drawn from the national grid to meet commissioning and start up power for the plant. Dual redundant systems are designed to provide a secure electrical supply arrangement that reduces downtime. The arrangement is shown in the single line diagram in Figure 5.3 below.

As shown in the diagram, EHV 400 kV power supply from the national grid is available through a new 400 kV switchyard with 400/33 kV grid transformers. The 33 kV supply from the grid transformers referred above is connected to 33 kV main switchboard two bus bar system for the main plant. Separate 160MVA transformers from the 400kV bus bar are provided for the supply to the ASU.

The 11kV supply is drawn from the 33kV/11kV transformers that are arranged in dual redundant supply mode. From the 11 kV bas bars the plant is supplied with the required electrical power to the drives at the various voltage levels using appropriate transformers and motor control centres as shown in the single line diagram, Figure 5.3. 230 V supplies are provided for lighting and small power. 110 V supplies are made available in the control building for instrumentation.

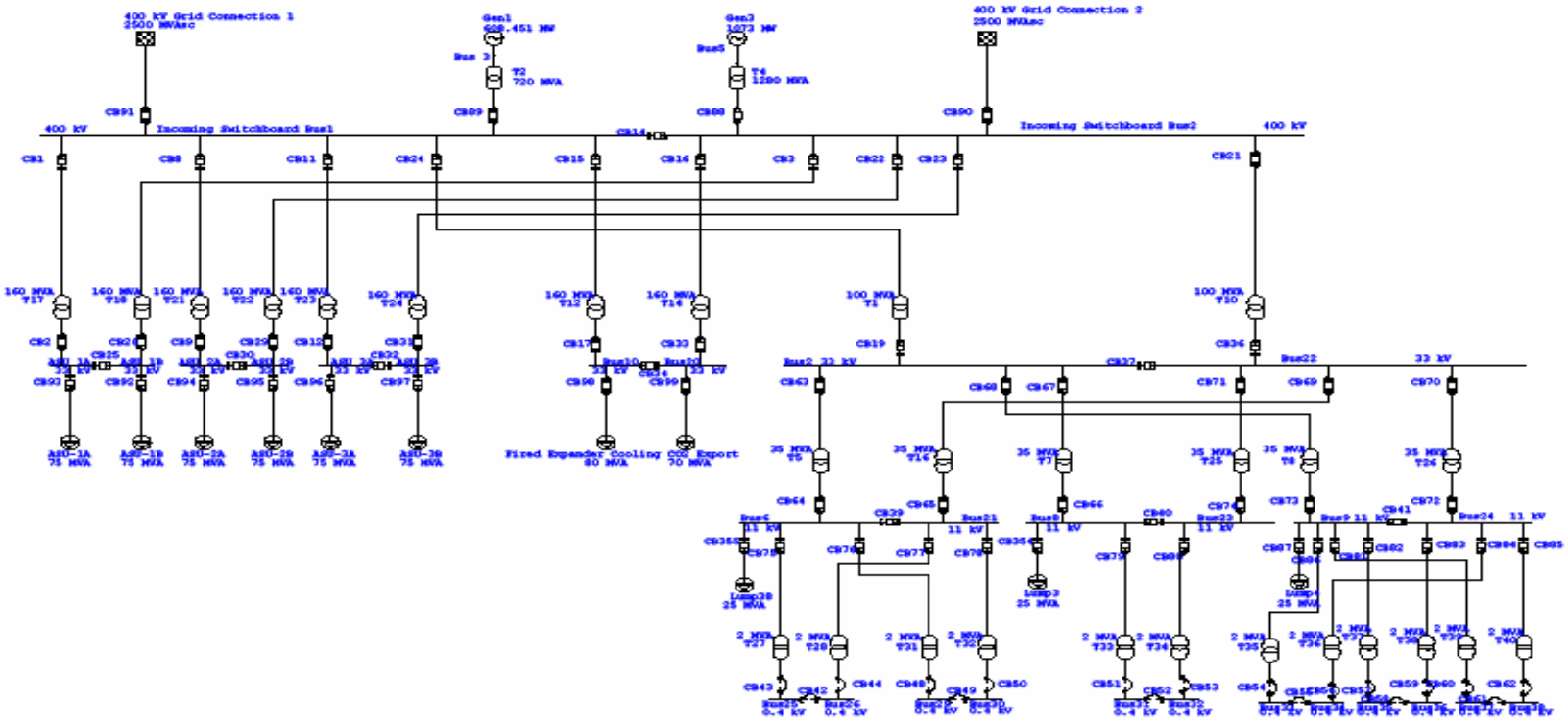


Figure 4.3 Electrical Single Line Diagram

5.4 Flare

A flare consisting of a self-supporting stack is provided on the plot. The majority of the process vents are directed to this flare on plot via the respective flare headers. The flare headers are continuously sloped towards the Flare KO Drum to achieve liquid drainage. The Flare KO Drum Pump pumps the liquids accumulated in the Flare KO Drum for disposal as necessary. The outlet vapour stream is routed to Flare Stack.

The plant contains a number of relief devices associated with process equipment, which potentially emit flammable vapours in the event of an upset condition. The plant systems are designed to collect all of the relief devices with potential to emit flammable vapours and direct them, via a header system into a blowdown vessel. Syngas contains significant proportion of water vapour and the blowdown vessel collects and contains any condensed liquid, whilst the gaseous phase is released to the flare. There are no incompatible fluids that could mix within the blowdown vessel. This design ensures the integrity of the system, whilst maintaining the simplicity and reliability.

The blowdown vessel is sized to allow a suitable vapour/liquid disengagement space. Level control instrumentation is incorporated to indicate the presence of any liquid, allowing prompt emptying, thereby ensuring there is always sufficient volume for liquid hold-up.

5.5 Control Building

The DCS and the ESD control systems are located in a central control building. The DCS architecture consists of a central dual redundant data highway system that is continuously monitored for fault detection and alarm giving very high level of security. The process controllers, printers, monitors, analysers, field instruments, communications devices are connected to this data highway and thus all the information flows along this data highway. A supervisory controller performs the higher level management functions.

The building is provided with HVac system that provides air conditioning and maintains a constant temperature and humidity in the control room. The building also houses the engineering console for the instrument engineer to interrogate the various control systems on-line and make any changes. Field cables enter the control building from underground sealed entry ports into the marshalling cabinets containing the I/O boards etc.

Sand filled buckets and CO_2 fire fighting extinguishers are located within the control building at various points.

A small refreshment area and changing facilities are included for the operating staff.

5.6 Instrument Air

The plant and instrument air system is shown in Figure 4.4. The IGSC plant has many users of plant and instrument air. In order to meet the demand, two compressors (1 duty + 1 standby) are provided. For drying of the instrument air, one air dryer is considered. Two air receivers, one each for plant and instrument air, are used with capacities giving a hold up of 15 minutes for each duty.

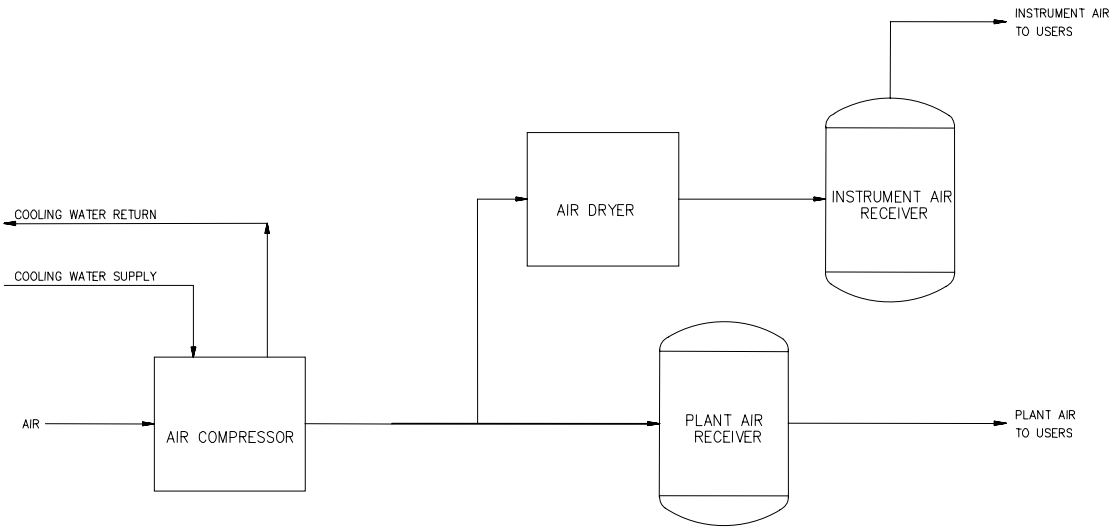


Figure 4.4 Instrument & Plant Air

5.7 Fire Water

The fire water requirement for the plant is based on industry practice and is estimated to be about 1,460 m^3/h during the peak period. Based on four hours storage requirement, a total fire water demand of 3,540 m^3 is required with 600 m^3/h drawn from the canal. A combined storage for raw and fire water of 5,000 m^3 is considered to provide four hours of fire water and raw water requirement. This results in a concrete reservoir of 40 m x 20 m x 5.0 m with a total storage volume of 4,000 m^3. In order to meet the requirement of fire water, two fire water pumps each of capacity 487m^3/h are used. The fire water pumps operate only in the event of a fire breakout inside the plant. In the event of electrical power failure, a standby diesel operated pump and diesel generator ensure fire water availability. Two jockey pumps, one of which is on standby duty, are also provided to maintain constant water pressure in the fire water mains.

A ring main of fire water is installed around the plant such that fire water supply is available at any point from two directions. Fire hydrants are provided every 50 m.

5.8 Potable Water

Potable water supply from the towns water mains is provided with a break tank of sufficient capacity. In the remote location potable water can be provided from the water treatment plant (WTP) with similar capacity tank.

5.9 Oxygen

The required oxygen for the combustion of coal is produced by liquefaction of air and separation by distillation in an air separation unit (ASU). For the utility case the required product oxygen purity is ≥95% and for the retrofit case it is ≥99.5% from the ASU. The maximum practical capacity of such an ASU is about 3500 te/h and therefore a multiple number of such units will be required to satisfy the duty of the utility case or the retrofit case.

5.10 Nitrogen

Nitrogen requirements for the plant are provided from the ASU by the installation of two sets of evaporators to vaporise nitrogen at the supply pressure in a header operating at

pressure 8 bar(g). The pressure header is used for purging operations around the plant during start up or after maintenance operation.

6.0 COST ESTIMATE

6.1 Investment Costs

6.1.1 Capital Cost Estimate Methodology

The plant installed cost estimate has been developed by Jacobs, with input from other study participants, utilising a combination of unit capacity factored and equipment factored estimating techniques and quotes from all the major licensers/vendors. These methods utilise historical data from plants with similar units or equipment.

Capacity-factored estimating is based on multiplying the cost of a similar unit, for which the direct construction costs are known from a prior project, by the ratio of the new unit's capacity to the capacity of the known unit. Capacity ratios are adjusted by an exponent chosen on the basis of the unit type. Adjustments are made as required to allow for differences in unit design bases, location, and time frame.

Equipment-factored estimates are based on the capacity of individual items of machinery and equipment which has been specified based on the heat and material balances. When developing equipment-factored cost estimates, the cost of each major equipment item (vessels, turbines, pumps, exchangers, etc.) is obtained from vendor quotes or estimating programs, such as Icarus, utilising experience and costs from previous projects. The costs for bulk materials (concrete, piping, electrical cable, etc.) and field labour hours required for their installation are then factored, based on an appropriate equipment parameter (duty, size, weight, etc.), to determine the total direct construction cost. The factors for bulk materials and labour man-hours are based on the design requirements of each equipment item and historical experience.

The costs for some units that are typically provided as a package are obtained from vendors or licensers of these units. Such units include the gasification unit, air separation unit, fired expander, HRSG, CO_2 compression and drying units and coal handling and storage unit.

The accuracy of the cost estimate is ± 30%.

Performance and/or cost data sources for some of the major units are given below in Table 6.1.

Item	Source
Gasification Unit Performance & Cost	GE Energy, Siemens
Fired Expander Performance & Cost	Siemens
Coolant Recycle Compressor Performance and Cost	MAN
Air Separation Unit Performance and Cost	Air Products, Linde(BOC)
CES Burner Performance and Cost	CES
CO_2 Compressor Performance and Cost	MAN
CO_2 Drying Performance and Cost	SPX Dehydration & Filtration
Steam Turbine Performance and Cost	Siemens
HRSG Performance and Costs	MAN
BOP	Jacobs

Table 6–1 - Performance and Cost Data Sources

The data supplied by these sources with the exception of balance of plant (BOP) accounts for over 80% of the total capital cost

For units/systems not shown in the table, the performance was developed by Jacobs and for the majority of individual exchangers, vessels, pumps, etc. vendor quotations were obtained. The remaining equipment, the balance of plant (BOP), performance and/or costs are estimated by Jacobs. The plant layout was developed for the utility case for estimation of various costs such as interconnecting piping, land costs etc. and it is given in the Appendix C.

The base estimates developed are adjusted to a northern UK location and third quarter 2008 time frame using location specific information. Escalation of the cost for a project built over several years is included separately in the economic analysis.

The following exchange rates have been utilised:

1£ = 1.8 US$

1£ = 1.265 Euros

The capital cost estimates are comprised of the following components:

- Direct Field Material Costs
- Direct Field Labour Costs (Subcontract Basis)
- Construction Management
- Site Temporary Facilities and Other Services
- Home Office Costs
- Freight
- Project Managing Contractor
- Contingency

The sum of these components is defined as the plant installed cost or EPC cost of the project because it contains the items typically within the scope of the EPC contractor. Owner's costs that are typically outside of the EPC cost are discussed in section 6.1.3.

A discussion of costs contained in each of the cost elements above is given in the Appendix D1.

6.1.2 Utility Plant Installed Cost Summary

The installed plant cost, broken out by major plant sections, is given in table 6.2. The systems incorporated within these major plant sections are described in the Appendix D2.

Unit	£
Coal Receiving, Storage & Handling	£13,503,907
Gasification	£343,223,930
Fired Expander	£72,890,538
HRSG	£243,582,180
Steam Turbine system & Deaerator	£330,274,192
Desaturator / LT Heat Recovery	£56,595,539
CO_2 Compression and Drying	£66,516,066
Air Separation Unit	£681,656,839
Raw Water & Secondary Water Treatments	£64,493,380
Electrical	£79,618,362
Utilities, Offsites & Amenities	£38,053,554
Interconnecting piping & large piperacks	£19,357,485
Direct Field Costs	**£2,009,765,973**
Construction Management Costs	22,401,000
Management Site Temporary Facilities	Included
Total Field Costs	**£2,032,166,973**
Freight	81,890,000
Project Management Contractor	Included
Home Office Engineering	40,647,800
Contingency	£315,043,327
Total Before Ow'er's Costs	**2,469,748,100**
Owner's cost	£307,749,000
Plant Installed Costs	**2,777,497,100**

Table 6.2 Utility Plant (1200MW Net Power) Installed Cost Summary

6.1.3 Owner's Costs

Costs that can be outside of the scope of the EPC contractor are termed owner's costs. These costs, listed below, are necessary to develop the project and put the plant in an operational condition, including:

- Initial Catalysts and Chemicals
- Water Charge
- Spare Parts Inventory
- Commissioning and Start-up
- Land
- Process Technology Paid Up License Fees
- Environmental Permitting
- Plant Mobile Equipment / Furniture / Laboratory and Shop Equipment
- Ow'er's Project Management
- Project Development
- Operator Training
- Insurance During Construction and Startup
- Other Costs

Based on previous project experience and guidelines of EPRI, IEA and other organizations, an allowance of 15% has been included in the unit costs which results in an overall allowance at 11% of the total project cost as owner's cost.

6.2 Operating Costs and Revenues

6.2.1 Estimating Basis

Annual operating costs and revenues are divided into fixed and variable components. Description of how these components have been estimated is given in the economic analysis in section 8.0.

6.2.2 Other Costs

The following operating costs are excluded from the this section because they are included as part of the economic analysis in section 7.0.

- Escalation
- Depreciation (non-cash expense)
- Interest
- Taxes

6.3 Development and Execution Schedule

As discussed earlier in section 3.6, it is necessary to install an industrial scale plant to thoroughly evaluate and prove the various details of the IGSC process. In particular it is essential to determine whether any sulphuric acid is formed in the liquid phase in the desaturator circuit or the sulphur species leave with the gaseous phase. This will provide a firm basis on which a utility scale plant can be designed and an execution schedule prepared with a fair degree of accuracy.

A general example of such a plant execution schedule is given in Appendix D3.

6.4 Retrofit Case

6.4.1 Capital Cost Estimate Methodology

As the name implies, a retrofit plant involves the modification of an existing power plant. For the purpose of this study it is assumed that a 500 MW generating conventional coal fired power plant such as that at Ferrybridge is being modified to convert to IGSC operation. Such a plant has coal handling and storage facilities, electrical switchyard, power turbines, amenities such as control building, admin building, laboratory, canteen etc. A significant part of these can be retained but the boiler and electrostatic precipitators will not be required and can be demolished to make space for the new equipment. As there is no normal exhaust from an IGSC plant, the chimney can be demolished as well.

The data for a retrofit plant is likely to vary from plant to plant and therefore no detail equipment sizing had been performed. Instead the costs are derived from the estimated costs of the similar units in the utility plant with unit capacity ratio raised by exponent 0.7. Due account is taken of the available equipment, new equipment and that required for extra generating capacity with the appropriate ratios. This is detailed below for each of the process units.

- Coal receiving, storage and handling

  There exists 500 MW worth of coal storage and handling facility and this will be reused. Since the retrofit case produces extra 311 MW power compared to 500MW at Ferrybridge, it is necessary to provide this additional coal storage and handling capacity. As the utility plant data is for 1200MW power, the cost of the additional coal storage and handling is determined by multiplying the utility cost for coal storage and handling by the ratio of 311/1200 to the exponent 0.7. This gives a cost of £7,351,167.

- Gasification

  For the retrofit total power generation of 811MW it is necessary to utilise three gasifiers instead of four for the utility case. Therefore the cost is directly reduced by this factor and the cost is £355,751,671.

- Fired Expander

  The cost of the fired expander is given by Siemens but this needs to be reduced by the two additional burners included in it. The revised estimated cost is £96,696,000.

- HRSG

  The cost of HRSG was quoted by MAN and it is £302,967,573.

- Steam Turbine System & Deaerator

  It is assumed that the existing steam turbine system will be utilised for the 500MW power generation. Therefore the costs associated with an auxiliary steam turbine for 311MW power generation needs to be accounted for. Along with the LP turbine a condenser and a deaerator are also required as it may not be possible to integrate with the existing equipment due to the possible longer separation distance that may be involved. The estimated cost is £195,936,876.

- Desaturator / LT Heat Recovery

  As the flow rate is 80% that of the utility case, the cost is reduced by the same factor to the exponent 0.7 and it is £66,904,189.

- CO_2 compression & Amenities

  Similar to desaturator the cost is reduced in direct proportion of the flow ratio compared to the utility case and it is £73,540,176.

- Air Separation Unit

  The cost of the air separation unit for retrofit is calculated based on oxygen consumption relative to that for the utility case. This is calculated to be £752,487,146.

- Raw Water and Secondary Water Treatments

  There is existing raw water and secondary water treatment for 500MW power plant and only additional capacity for extra 311MW needs to be provided. Therefore this is calculated for this capacity increase from the utility case estimate. These costs are £ 22,109,657 and £1,441,226 respectively for raw water and secondary water treatment.

- Electrical

  There is existing switchgear and transformers for 500mW plant and only additional 311MW worth equipment is necessary. This is calculated to be £43,342,116.

- Utilities, Offsites and Amenities

  There is a flare on site and majority of amenities such as admin building, control building, laboratory, workshop etc. can be reused. Therefore it is assumed that only 20% of the cost of amenities for the utility case is required for the retrofit which is £6.676,255. The additional utilities need to be provided in proportion to the capacity factor to the exponent 0.7 and the cost is £14,800,286.

- Interconnecting Pipework and Large Piperacks

  This is calculated based on the capacity ratio factored with the utility case and the cost is £20,612,380.

In addition to these costs, there will be requirement for the demolition of some of the existing equipment such as the boiler and the electrostatic precipitators. These are usually fairly large pieces of equipment and significant amount of structure, cladding, insulation and ducting is involved. It is not known if there is any asbestos in the lagging at Ferrybridge. For the purpose of this study it is assumed that no special needs such as asbestos handling will be necessary. An allowance of £10,000,000 is made for the demotion activities on the existing site. No account is taken of the scrap value of the significant amount of metal and copper that can be realised which will reduce this charge.

6.4.2 Retrofit Plant Installed Cost Summary

Based on the above analysis the installed plant cost of a retrofit at Ferrybridge, broken out by major plant sections, is given in table 6.3.

Unit	£
Coal Receiving, Storage & Handling	£3,561,946
Gasification	£256,970,234
Fired Expander	£69,846,457
HRSG	£218,842,678
Steam Turbine system & Deaerator	£329,699,764
Desaturator / LT Heat Recovery	£45,197,684
CO_2 Compression and Drying	£53,120,302
Air Separation Unit	£543,544,315
Raw Water & Secondary Water Treatments	£17,007,954
Electrical	£31,300,768
Utilities, Offsites & Amenities	£15,509,908
Interconnecting piping & large piperacks	£14,885,829
Direct Field Costs	£1,599,487,839
Construction Management Costs	£15,893,369
Management Site Temporary Facilities	Included
Total Field Costs	£1,615,381,208
Freight	£58,100,440
Project Management Contractor	Included
Home Office Engineering	£28,839,358
Contingency	£223,521,259
Total Before Ow'er's Costs	**£1,742,270,739**
Demolition	10,000,000
Owner's cost	£218,345,979
Plant Installed Costs	**£1,970,616,718**

Table 6.3 Retrofit Plant (811MW Net Power) Installed Cost Summary

7.0 ECONOMIC ANALYSIS

7.1 Introduction

This Section contains a simple examination of the potential economic performance of the IGSC Process.

It is the first evaluation of a novel coal based power production system since the advent of IGCC.

For reasons explained elsewhere in this Report, it is considered that the most appropriate application of IGSC in the current power market is as a retrofit for existing coal fired Power Stations with no carbon emission control.

A single example is taken to display the economic characteristics of the generic IGSC flow scheme when applied as a retrofit, with the aim and objective of providing a simple tool to apply when gauging suitability of the technology for a specific plant.

The precise means by which a particular plant could be retrofitted is obviously site specific, and for the purposes of the analysis a typical UK plant has been chosen, namely the Ferrybridge Power Station, which is owned and operated by Scottish & Southern Energy.

The key element around which the retrofit design is based is the steam turbine, and the technical data for this has been obtained through the good offices of Siemens. However, in order to keep on a consistent base for all the development work and for all the cases, including the Retrofit Case, the base data etc. specified in Section 3 “Design Basis” of this Report applies.

–In typical IGCC processes, the proportion of coal to oxygen consumption is 40%. However, the IGSC process requires 100% oxygen consumption. As a result, the ASU represents the most significant capital cost.

For this reason, it was considered appropriate to evaluate the feasibility of buying oxygen ‘over the fence’ from an ASU owned and operated by a well established and reputable supplier such as Air Products or Linde, and compare this data with the ASU within the plant battery limits.

Therefore in performing the economic analysis for the Retrofit Case; two options are investigated:

1) Option–1 - including ASU

2) Option 2 – excluding ASU (oxygen is bought ‘over the fence’)

7.2 Key Parameters

The six interlinked parameters which determine the commercial attractiveness of the process are:

- Capex & Opex
- Availability
- Coal Input
- Oxygen Input
- Net Power Output
- By-product CO_2

In order to maintain generic simplicity, the balance of the operating plant is considered essentially consistent under all operating conditions.

7.3 Capital Cost

The capital investment consists of the sum of money required up-front to purchase, build and install the necessary machinery, equipment and buildings and also the costs of validation and contingencies. This is called the Fixed Capital Investment (FCI). An additional sum used to start operation is the Working Capital (WC) which together with the FCI amounts to the Total Capital Employed (TCE).

The overall capital cost laid out in Section 6.4 relates to the Retrofit Case with the ASU included. The cost with ASU excluded was derived from it. These costs are listed as fixed capital investment in the table below for the economic analysis.

		OPTION 1	OPTION 2
Fixed Capital Investment	**(FCI)**	**1,970,616,719**	**1,218,129,573**
Loan Interest Accrued		209,673,619	129,608,987
Start-up Costs		197,061,672	121,812,957
Total Installed Cost	**(TIC)**	**2,377,352,009**	**1,469,551,517**
Working Capital	(WC)	295,592,508	182,719,436
TOTAL CAPITAL EMPLOYED	**(TCE)**	**2,672,944,517**	**1,652,270,952**

Table 7.1: Cost data for Economic Analysis

7.4 Operating Expenses

The operating expenses represent the annual production costs required to generate 811 MW of power in the retrofit case, which can be split into fixed and variable components.

Fixed Costs

Fixed costs are those which do not vary with production output or sales level and therefore are set year on year. These include:

- Operating Labour
- General & Administrative
- Maintenance Costs
- Insurance
- Business Rate

The majority of these fixed costs has been evaluated and taken as a percentage of the FCI for the purpose of generating a cash flow for the project, unless otherwise specified.

Operating Labour

The operating labour force covers shift operators, day maintenance staff and day staff required to run each of the process areas and are directly engaged in the operation of the plant. Shift operators are expected work 8 hour shifts.

Costing is based on the gross annual salaries (mean value) obtained from <2007 Annual Survey of Hours and Earnings First Release> by Office of National Statistics. Figures for Yorkshire (location of plant) have been used and the costs have been escalated to include inflation and benefits etc. to give total annual remuneration for operating labour.

General & Administrative

The general and administrative personnel are those who are not directly associated with the running and maintenance of the plant e.g. clerical staff and legal advisers. This has been estimated as 30% of the operating labour force.

Maintenance Costs

Annual maintenance costs have been estimated as a percentage of FCI for each process area. Different percentages are applied to reflect the difference in severity of operation of each process area; figures are based on experience on similar projects. The maintenance costs also take into account spares, such as the replacement of slag screens.

PROCESS AREA	% of FCI
Gasification	10
Fired expander	2
HRSG	3
Steam system	
Desaturator	3
CO_2 Compresseion	
ASU	2
Utilities, offsites & other costs	2

Table7.2: Maintenance costs as percentage of FCI for each process unit

Insurance

The annual insurance cost has been estimated as 1% of the total FCI.

Business Rates

Business rates have been charged at 0.5% of FCI to cover costs to the local council.

Variable Costs

The variable operating expenses are divided into two main categories; raw materials and utility costs, both of which change as a function of the power output.

Availability

It is often thought that higher efficiency may be obtained by spending more on equipment. In fact, the efficiency is mainly defined by the process design and extra capital investment is best spent on improving availability by buying more reliable equipment.

The normal requirement of the power industry for availability for base load plant is 92% or 8000 hours per annum. All the equipment used in IGSC is normally obtained from power industry suppliers and is designed and fabricated to achieve this degree of availability.

The main exception, which does not come from the traditional power industry, is the gasification system whose gasifiers will not exhibit 92% availability if operated in single stream mode. However it is normal practice in the chemical industry, where gasification is commonly employed, to raise this to more than 92% by provision of an installed spare gasifier.

Thus the total plant may be regarded as achieving a normal operating availability of 92%

Annual costs have been derived by assuming the plant operates at 6132 hours (70% capacity) in year 1 allowing for commissioning and running in and 8000 hours (92% capacity) each year thereafter. Miscellaneous costs have also been included for disposables & consumables e.g. lube oil and flocculants and has been taken as 0.02% of FCI.

Raw Materials

The key raw materials required for the process are:

- Coal
- Oxygen
- Nitrogen (for purging, inerting and start-up)
- Natural Gas
- Additives (chemical dosing required to treat the fresh water input)

To determine the annual cost of these items, quantities were calculated through the use of simulation and mass balances, while costing per unit has been derived from latest industry sources. All costs have been converted to GBP to be consistent as per the rate for the third quarter 2008.

For Option 1, the operating cost for oxygen remains zero as it is produced 'in-house' using an ASU. With Option 2, the cost of oxygen 'over the fence' is based on Linde's quote.

The table below details the basis of cost estimation used:

Raw Material	Pricing	Reference
Coal	180 USD/te	*Goldman Sachs, spot thermal rate (03/09/08)*
Oxygen	43.74 £/te	*Linde Quote (12/09/08)*
Nitrogen	£1.3m per startup/shutdown	*Air Products Quote*
Natural Gas	85.8 p/therm	*CitiGroup, UK Spreads Commodity Prices (29/07/08)*
Additives	91,789 GBP	*Estimated*

Table 7.3: Raw Material Prices

Waste Disposal Costs

The waste disposal costs refer to the specific costs in running the waste system and depend on the level of waste treated, including management and legal expenditure. This is charged at the rate of 5% of FCI.

Utility Costs

Fresh water is the only utility that must be imported from outside the battery limits from a canal. Consumption has been calculated in the water balance and the costing is based on rates for 2008/9 provided by Welsh Water (OFWAT), a fixed charge at £105,519/yr and volumetric charge at £0.6244/m^3.

Although electricity is required for the running of the plant and represents a variable operating expense; the cost is only necessary for start-up in Yr 1. Thereafter, the system will be integrated with onsite power generation to meet internal electricity demands. The electricity demand for start-up has been included as part of start-up costs.

7.5 Sales Revenue

Majority of the sales revenue is derived from the net power produced by the retrofit plant, to be sold to the grid. Option 1 generates a smaller revenue stream than option 2, as the net power is reduced to 811 MW. This is due to the additional internal power consumption of the ASU (311MW). In the case of option 2, the net power is 1088 MW. It is also assumed that the CO_2 by product can be sold to generate further revenue.

The table below indicates the pricing basis used to calculate annual sales revenue:

Product	Pricing	Reference
Electricity	90 GBP/MWh	*Bloomberg*
CO_2	25 €/te	*European Energy Exchange July 08 futures for 2012*

Table 7.4: Sale Price / Credits

Other potential sources of revenue were also considered such as water (> 80°C) in the purge stream to be sold for CHP. However, no revenue stream was assumed for the base case. Slag from the gasifiers can also be used as building material but it was considered appropriate to treat this as a neutral cost due to its necessary removal cost.

7.6 Loan & Investment

The fixed capital investment required for the purchase and installation of equipment for the plant during commissioning and construction is estimated at £1.97 bn (Option 1) and £1.22 bn (Option 2). It has been assumed that 30% of this cost is financed through equity and 70% is raised by a loan.

Loan will attract interest payable annually, at 8% of the loan amount.

The rate of repayment of the loan is at 7% of the total borrowed at the end of each operating year. The final loan payback time for both Option 1 and Option 2 is 15 years.

For cash flow purposes, the following has been applied:

- Loan interest for each year is on the outstanding sum at the START of that year
- Repayment of loan takes effect at the END of that year
- Repayment of loan each year must effectively come out of the Total Sales Revenue, therefore starts in Yr 1 of operation

The commissioning and construction period is expected to take 3 years. FCI and consequently the loan requirement are to be spread over this period in the proportion; Year -3 = 20%, Year -2 = 50% and Year -1 = 30%.

The table below summaries the full investment required starting from the first year of commissioning.

Amount (£) Period of Construction	YR -3	YR -2	YR -1	YR 0
OPTION 1				
FCI	394,123,344	985,308,359	591,185,016	
Loan Interest Accrued	22,070,907	77,248,175	110,354,536	
Start-up Costs				197,061,672
Total Installed Capital	416,194,251	1,062,556,535	701,539,552	197061671.9
Working Capital				295,592,508
TCE	416,194,251	1,062,556,535	701,539,552	492,654,180
OPTION 1				
FCI	243,625,915	609,064,786	365,438,872	
Loan Interest Accrued	13,643,051	47,750,679	68,215,256	
Start-up Costs				121,812,957
Total Installed Capital	257,268,966	656,815,466	433,654,128	121812957.3
Working Capital				182,719,436
TCE	257,268,966	656,815,466	433,654,128	304,532,393

Table 7.5: Total Capital Employed

7.7 Depreciation

Depreciation is an annual income tax deduction that allows the recovery of the cost of certain assets (except land) over the time they are being used. It is an allowance for the wear and tear, deterioration, or obsolescence of the assets.

Theoretically, the cost of an asset should be deducted over the number of years that the asset will be used, according to the actual drop in value that the asset suffers each year. At the end of each year, all depreciation claimed to date could be subtracted from the cost of the asset, to arrive at the asset's net book value which would be equal to its market value. At the end of the asset's useful life for the business, any undepreciated portion would represent the salvage value for which the asset could be sold or scrapped.

To compute the amount of annual depreciation; it has been calculated on FCI on a straight-line basis. Working capital however, is not depreciated as it recoverable at the end of the plant life.

Typical depreciation allowances for chemical plants are 10-15% (onsites) and 5-8% (offsites). For the purpose of this economic analysis; the depreciation percentages are assumed 10% for both onsites and offsites.

7.8 Cash flow statement

Having obtained all necessary costing data, including financial investments and loans, cash flow statements were set up for both Option 1 (incl. ASU) and Option 2 (excl. ASU).

The cash flow statement is based on the following project schedule. The main points can be summarised as follows:

- Plant life = 30 yrs
- Commissioning & construction phase = 3 years
- Yr 0 = Point of start-up.
- The accrued loan interest equals 8%. Interest is payable annually.
- Depreciation is straight-line, at 10% for onsites and offsites
- Sales start in year 1
- The first positive cash flow year is the first year of sales

7.9 Discounted Cash Flow (DCF)

The DCF evaluates the investment by estimating future cash flows and taking into consideration the time value of money.

Net present value (NPV) shows the value of a stream of future cash flows discounted back to the present by a percentage that represents the minimum desired rate of return, often the cost of capital.

The internal rate of return (IRR) is defined to be the discount rate that makes the net present value of the cash flow equal to zero, and thus enables the intrinsic value of the project (as well as a means of comparing Option 1 and Option 2) to be determined.

It indicates a break-even rate of return i.e. the discount rate at which the value of the cash outflows equals the value of the cash inflows. Below this value an investment results in a positive NPV and above which; it results in a negative NPV (should be avoided).

In order to be acceptable, a project must be expected to earn an IRR that is at least several percentage points higher than the cost of borrowing, to compensate the company for its risk, time and trouble associated with the project.

- Option 1 (incl. ASU): IRR = 8.6%
- Option 2 (excl. ASU): IRR = 11.9%

7.10 Single Example

The following table illustrates the commercial characteristics of an existing plant retrofitted with the IGSC process.

The costs ascribed to the basic parameters are taken from current market conditions.

The economic analysis spreadsheet developed for the project could be made available for specific evaluations if required.

	Units	ASU		Note
		Included	Excluded	
Fixed				
Investment Cost	$/kW installed	4,235	1,801	2,3
Efficiency	% net LCV	27.9	40.7	4
Variable				
Coal Price	$/te	180	180	5
Oxygen Price	£/te	-	43.74	6
CO_2 Credit	€/te	25	25	5
Electricity Sale	£/MWh/h	90	90	5
Availability	%	92	92	7
Net Output	MWh/h	811	1088	
IRR	% per annum	8.68	11.92	

Table 7.6: Commercial Characteristics of an IGSC Retrofit

Notes:

1. A full sensitivity analysis spreadsheet has been prepared and could be made available for the evaluation of specific applications of IGSC.
2. The finance gearing is taken as 70% loan 30% equity.
3. The loan is paid back over fifteen years at 1% over Libor.
4. The stated efficiencies both assume retention of the old steam turbine together with its feed water heating system. This means that waste heat from the oxyburn cycle cannot be used for this preheat duty. If a new Steam Turbine were to be used to replace the existing steam turbine then, for example, the efficiency of the overall plant (including the ASU) would rise to 32%.
5. The ascribed figures are given as typical of today's markets.
6. The oxygen price has been obtained from international suppliers of very large scale ASU's who would be prepared to supply oxygen both over-the-fence or within the battery limits as part of the main plant.
7. Excludes initial year of operation when availability has been assumed to be 70%.

7.11 Sensitivity Analysis

7.11.1 General

The cash flows generated to evaluate the feasibility of Option 1 (incl. ASU) and Option 2 (excl. ASU) for the retrofit plant are based on values considered most realistic at present.

However, variability in the price of key parameters may arise, causing significant deviations in the actual cash flows achieved in any year. Such parameters are the CO2 credit, price of electricity, price of oxygen etc.

7.11.2 Sensitivity to Carbon Credits

The economic evaluations carried out here assume a fixed credit price of €25/te for captured CO_2. However the volatility of this price since the inauguration of the European Trading Scheme (ETS) has been fluctuating wildly from near zero to more than €30/te.

The following diagram illustrates the sensitivity of the IGSC retrofit to the price for captured CO_2:

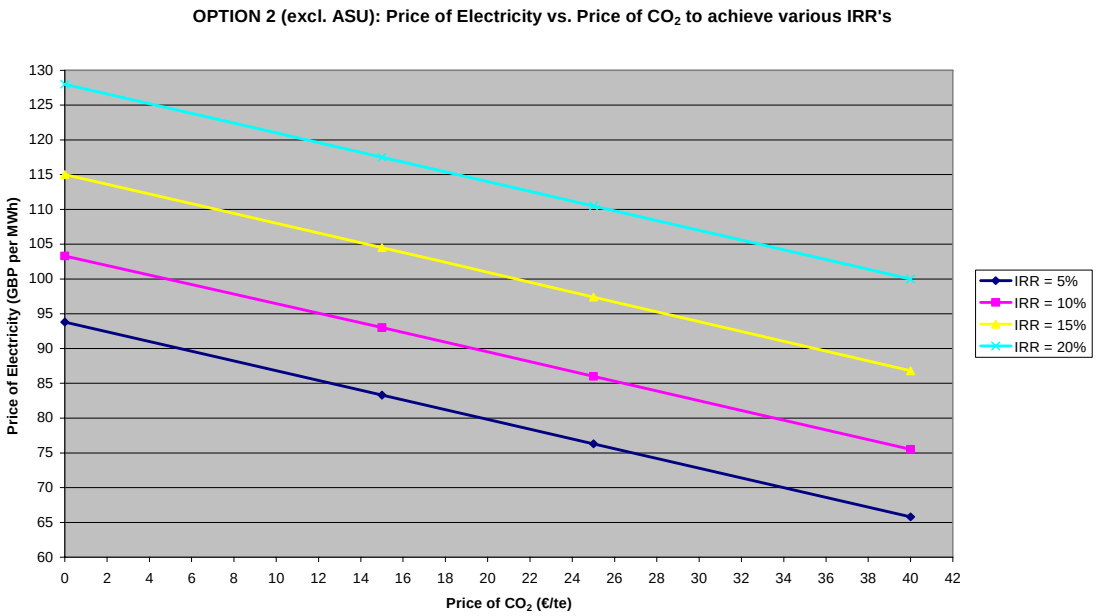


Figure 7.1: Electricity Price Sensitivity to Carbon Credit

All parameters including the rate of return are assumed constant whilst the price for captured CO_2 is varied.

The single example of a captured price of €25/te with a corresponding electricity price of £86/MWh/h results in an IRR of 10%.

If the credit price then falls to zero, the price obtained for sold electricity would have to rise to £103/MWh/h to achieve the same IRR of 10%. This also indicates that the cost of 100% CO_2 capture is £17/MWh/h for this specific example.

At the other extreme, if the credit price rises, then the cost of electricity production falls until at €40/te - the figure that has been mooted by others as necessary to make CCS commercially viable – the price of electricity required to make an IRR of 10% is only £76/MWh/h.

8.0 R&D ACTIVITIES AND RESULTS

8.1 Summary

This section describes the parallel activities is of Imperial College during the execution of the project in investigating the physical and chemical properties of the mixtures of steam and gas to contained within the plant process and especially at condensing conditions.

8.2 Introduction

The IGSC process involves multi-component fluid mixtures, the physiochemical properties of which are required for proper evaluation and optimisation of the design. Thermodynamic properties are fundamental to the operation of thermal power plant, as they impinge directly on the efficiency of the process. It is also desirable to know key chemical/phase equilibria and kinetic data for minor components in the process, especially those containing sulphur, in order to assess both material compatibility issues and separation and clean-up of the produced CO_2.

The two feed gas streams entering the combustion system are a syngas/steam mixture and oxygen, both of which contain impurities including nitrogen and compounds of sulphur. Accordingly, the products of combustion and quenching in the burner system will be primarily a mixture of steam and carbon dioxide, containing also residual oxygen, inerts, and oxides of sulphur and nitrogen. The thermodynamic properties of this stream are easy to model to engineering accuracy as they pass in the gas phase through the hot expander. However, as the stream cools in the heat-recovery steam generator (HRSG), condensation of acids is a major concern from the materials compatibility point of view. Moving downstream to the desaturator, we need to know the phase-equilibria and chemical-equilibria taking place in order to optimise the design for effective and efficient separation and clean-up of CO_2, including the key issues of sulphur removal.

The requirements for physiochemical data and models were not fully established at the proposal stage of the project as, for example, it had not then been decided to place sulphur removal at the back end of the process. The experimental research was therefore focused on the known requirement for solubility data of CO_2 and SO_2 in water, as this property is fundamental to the operation of the desaturator and few data existed for the temperatures and pressures at which

the process would operate. In order to study this key property, a new laboratory apparatus was designed and built during this project. Solubility measurements were made on CO_2 and SO_2 in water over a range of pressures and temperatures. The measurements on CO_2 serve largely to verify the performance of the apparatus, while the new data for SO_2 significantly extend the temperature range over which this property is known. The issue of Acid gas Dewpoint Temperature (ADT) was recognised as the project evolved and addressed through a literature review and modelling effort.

8.3 Solubility of CO_2 and SO_2 in Water

Process simulation was carried out in this project on the AspenTech process simulation model with detailed consideration of a wide range of chemical species. The software offers a large number of possible thermodynamic packages for phase equilibrium calculations from which one based on the following combination of models was selected:

- NRTL-electrolyte model (for components in the liquid phase other than dissolved gases)
- Henry's law (for dissolved gases)
- Equation-of-state model (for the gas phase)

The parameters in such models are based on consideration of experimental and other data for pure substances and binary mixtures, and Aspen Plus has in its database the parameters pertaining to all the key components present in the IGSC process. However, some of these parameters, especially the extended Henry's-law constants, are not validated in the temperature and pressure ranges in question. Accordingly, the aim of the study was to gather experimental data on the binary systems (CO_2 + water) and (SO_2 + water) against which to validate the models used in the process simulation.

8.3.1 Literature data for (CO_2 + water) and (SO_2 + water)

As a part of this project, a detailed review of the scientific literature has been carried out to establish in detail the available data and correlations. This study focused on the Henry's law constant at infinite dilution but also covered the additional data necessary to describe solubility at finite concentrations. Most of the available data pertain to total pressures p close to p = 0.1 MPa. For both dissolved species, but especially for SO_2, aqueous-phase chemistry may be

significant as these acid gases undergo partial dissociation when dissolved in water. One result of this is that the apparent or gross solubility does not accurately follow Henry's law over a wide range of pressure. Accordingly, a correct treatment of gas solubility should be based on the extended Henry's law applied to the molecular species, plus consideration of the liquid-phase chemistry. For example, in relation to the dissolution of SO_2 in water, we should consider at least the following three processes:

$SO_2(g) = SO_2(aq)$ (8.1)

$H_2O(l) + SO_2(aq) = H^+(aq) + HSO_3^-(aq)$ (8.2)

$HSO_3^-(aq) = H^+(aq) + SO_3^{2-}(aq)$ (8.3)

Nevertheless, experimental solubility data are usually reported in the form of apparent or gross mole fractions $\bar{x}_2$ in the liquid phase (irrespective of chemical state) and not the true mole fraction x_2 of the undissociated dissolved gas. Here, subscript 2 designates a property to the solute.

Correlations of $\bar{x}_2$ as a function of temperature T at a constant solute partial pressure p_2 = 0.101325 MPa have been published in two IUPAC-sponsored papers [8,9]. For CO_2, the distinction between $\bar{x}_2$ and x_2 is not highly significant and the correlation is valid in the temperature range 273 ≤ T/K ≤ 433. We have calculated derived values of Henry's constant at infinite dilution $K_{H,2}^{\infty}$ over the same temperature range. Figure 8.1 shows $\bar{x}_2$ and $K_{H,2}^{\infty}$ as functions of temperature and we note the maximum observed in $K_{H,2}^{\infty}$ at T = 421 K.

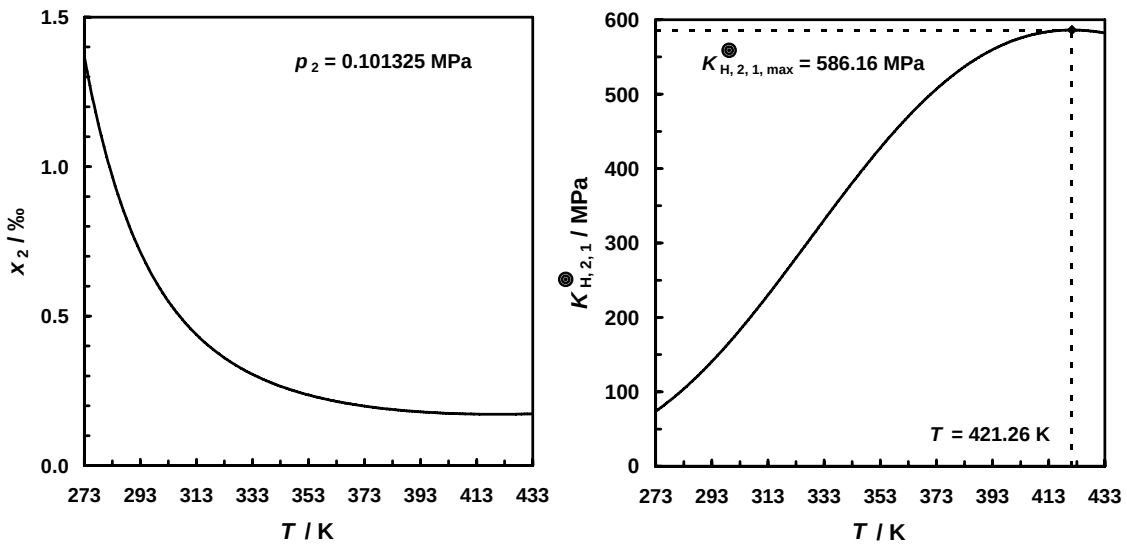


Figure 8.1. Left: apparent mole fraction $\bar{x}_2$ of dissolved CO_2 in water as a function of temperature T at a constant partial pressure p_2 = 0.101325 MPa [8]. Right: Henry's constant for CO_2 in water as a function of temperature T as calculated in this work.

Our modelling based on this correlation shows that the available experimental solubility data at pressures up to around p = 1 MPa are well represented by the extended form of Henry's law ignoring acid-base reactions in the liquid phase. Accordingly, we conclude that the available data and models are soundly based in relation to CO_2 for application in the study of the desaturator as this is expected to operate at a pressure of approximately p = 1 MPa and at temperatures not higher than about 450 K, so that only a short extrapolation with respect to temperature is required.

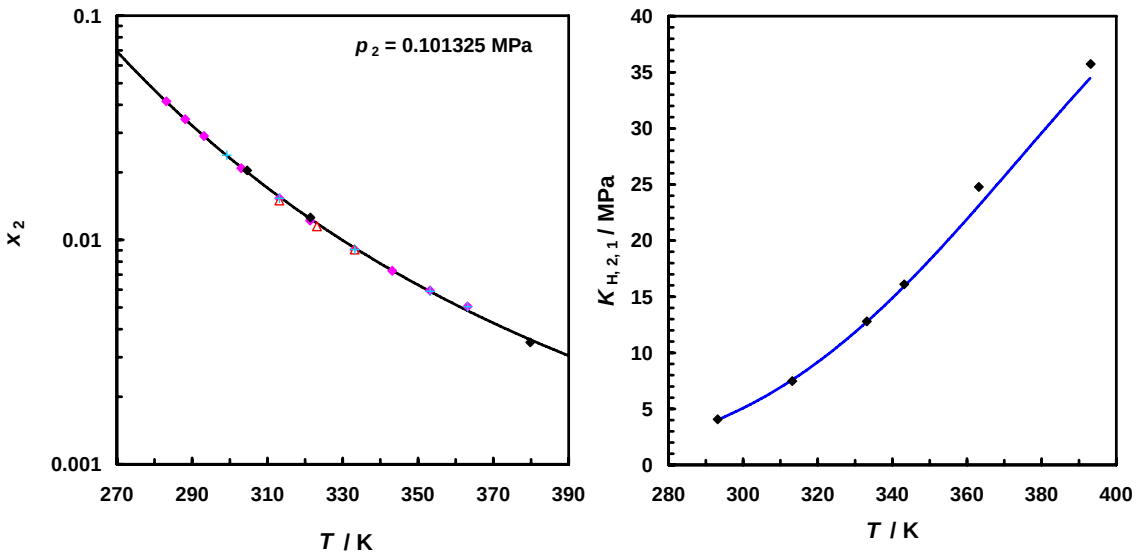


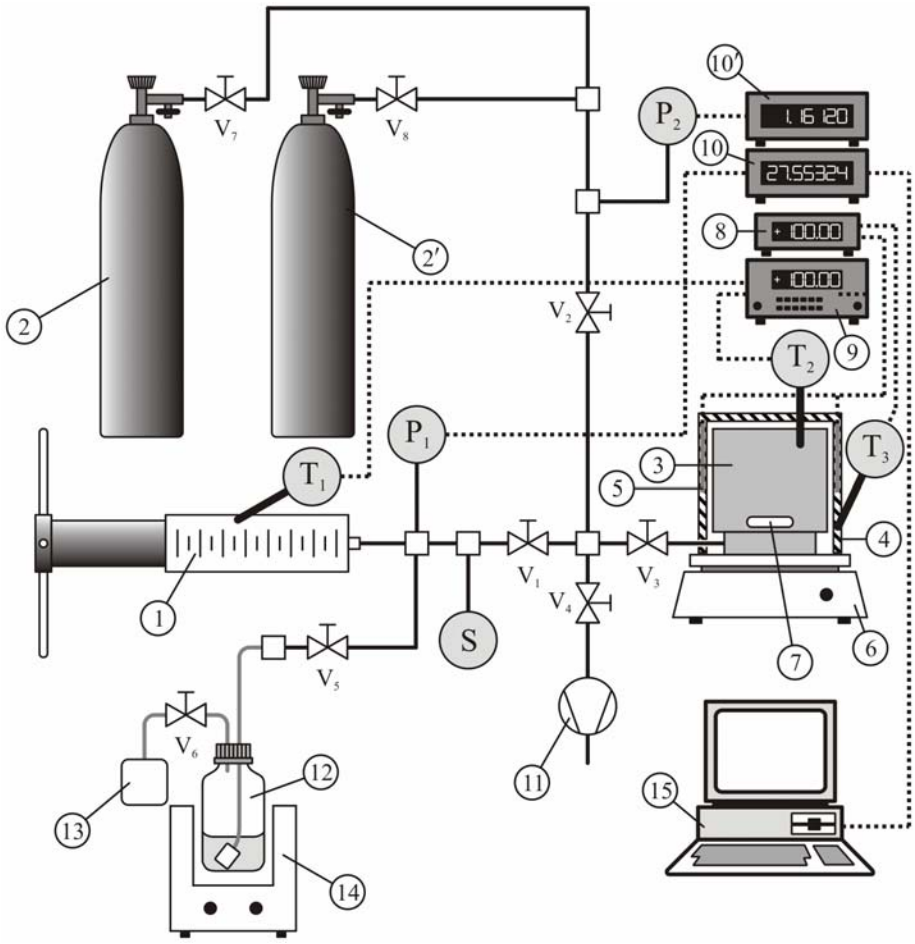
Figure 8.2. Left: apparent mole fraction $\bar{x}_2$ of dissolved SO_2 in water as a function of temperature T at a constant partial pressure p_2 = 0.101325 MPa (———, [9]; symbols, various literature data). Right: Henry's constant for SO_2 in water as a function of temperature T (———, calculated in this work; symbols, literature data).

For SO_2, the solubility data at or near p_2 = 0.101325 MPa available in the literature extend over a more limited temperature range and the correlation of $\bar{x}_2$ is valid for 278 ≤ T/K ≤ 383. In this case, aqueous-phase chemistry is significant and, in our modelling, we have allowed for the influence of reactions (8.2) and (8.3) to obtain the true mole fraction x_2 from the correlated values of $\bar{x}_2$ and thence to obtain and correlate the values of Henry's constant at infinite dilution. Both correlations are shown in figure 8.2 and we note the higher gross solubility of SO_2 when compared with CO_2 at the same temperature, and the much high values of $K^{\infty}_{H,2}$.

8.3.2 Apparatus and Experimental Method for Solubility Measurements

The experimental apparatus constructed during this project for the determination of the bubble point of binary (solvent + gas) systems by means of a synthetic method is schematically shown in figure 8.3. It comprised a high pressure cell (made from Hastelloy C276 and rated to p < 35 MPa) to which, via a system of 1/16″ high-pressure stainless-steel tubing and needle valves (V1-V8), a gas cylinder and a high-pressure displacement pump were connected. The high pressure cell was of cylindrical shape and had an inner volume of around 65 cm^3. It consisted of two main parts: a thick-walled bottom part and a top plate which was connected to the bottom part by eight

high-tensile stainless steel screws. In order to provide sealing of the vessel, a gold plated stainless steel o-ring was placed in between the two parts of the cell. The torus-shaped ring was hollow and filled with nitrogen at 20 MPa to provide sufficient elasticity when being compressed. When assembled, the o-ring was surrounded by a cylindrical retaining plate made of stainless steel. The retaining plate not only assists in aligning the ring concentrically around the centre of the cell, but served as a spacer to provide an appropriate deformation of the ring. In order to provide a constant temperature, the high pressure cell was encased by a cylindrical aluminium shell equipped with four electrical cartridge heaters and a platinum resistance thermometer, and insulated on the outside by a 12 mm thick layer of expanded silicone rubber foam. The heaters and temperature sensor were connected to a PID process controller that controlled the temperature of the aluminium shell to within ± 0.05 K. The cell-thermostat assembly was placed on a magnetic-stirrer unit that drove a standard PTFE-coated magnetic stirrer bar inside the cell. Two Paroscientific Digiquartz pressure transducers were used for monitoring the pressure. The first pressure transducer, covering the range $p < 6.9$ MPa, was located in the lines behind V1 which, during the execution of the actual experimental runs, were permanently filled with the liquid solvent. The other pressure transducer, capable of monitoring pressures of dry gases in the range $p < 14$ bar was built into the lines behind V2 and served to measure the pressure of the gaseous component during initial filling of the cell. A second gas cylinder (helium) allowed the introduction of an inert purge gas for use during the process of emptying and cleaning of the cell. The temperature of the liquid in the pump and the actual temperature of the solubility cell were measured with platinum resistance thermometers. The liquid reservoir, which could be kept under reduced pressure, was placed in an ultrasonic bath thereby allowing for *in-situ* degassing of the solvent. For the purpose of pressure compensation during filling of the liquid screw injector, an un-pressurised container filled with He was used. Evacuation and drying of the system was performed by means of a scroll-type vacuum pump.



(1)	High pressure generator for liquids		
(2), (2′)	Gas cylinders containing (CO_2 or SO_2) and He, resp.		
(3)	High pressure cell (Nickel-base alloy AL 276™)	S	Safety ruptur disk (p_{max} = 35 MPa)
(4)	Heater shell (Al)	T_3	Thermoprobe
(5)	Electrical cartridge heaters	T_1, T_2	Platinum resistance thermometer
(6)	Magnetic stirrer	P_1	Pressure transducer ($0 < p$ / MPa < 70)
(7)	PTFE coated magnetic follower	P_2	Pressure transducer ($0 < p$ / MPa < 1.4)
(8)	Temperatur controll unit		
(9)	Digitalmultimeter (temperature readout unit)		
(10), (10′)	Pressure readout unit		Needle valves (V_1-V_8)
(11)	Vacuum pump		High pressure stainless steel tube
(12)	Flask containing solvent component		PTFE tubing
(13)	Gas container filled with inert gas		Electrical connections / signal transmission cables
(14)	Ultrasonic bath		
(15)	Personal Computer		

Figure 8.3. Apparatus for gas solubility experiments at elevated pressure.

In order to establish a linear relation between the number of turns corresponding to a particular piston stroke and the volume displaced by the piston, it was necessary to execute calibration measurements on the pump. In these experiments, water was displaced from the pump and weighed on a precision analytical balance. The temperature and pressure of the liquid in the pump were both measured and the density obtained from the equation of state of Pruss and Wagner [i0]. The averaged slope of the straight regression lines drawn through the plots of V versus N, where V is the volume and N is the number of revolutions of the screw, was found to be (0.7018 ± 0.0002) cm^3. The volume of the cell was also determined by calibration measurements in which water was transferred quantitatively from the pump into the previously evacuated cell. The volume of the cell and tubing up to V3 (with the original gold-plated stainless-steel o-ring in place) was found to be V = (67.024 ± 0.002) cm^3. The short tube section located between V3 and the inlet/outlet of the cell represents the largest dead volume. The inner volume of this section was estimated by weighing it (a) empty and (b) filled with water and found to be (0.102 ± 0.002) cm^3.

8.3.3 Experimental Procedure

The pump was completely filled with analytical grade de-ionised and de-gassed water. Having the dried cell and set the desired temperature for filling, the cell and adjacent lines were evacuated (V2-V4 open, other valves closed). The cell was then filled with the gas to the desired initial pressure. The amount of gas introduced in this way was calculated from the calibrated cell volume, the measured temperature and pressure under filling conditions and the equation of state of the gas. Values V7 and V3 were closed, and the remaining sections of the lines previously filled with gas were evacuated again. The temperature of the cell was reset to the desired experimental temperature (if different from the filling temperature). After closing V2, V1 was opened carefully and by operating the liquid pump the lines enclosed by V2-V5 completely filled with water from the pump and the pressure adjusted to slightly above the initial pressure of the gas in the cell. Subsequently, a portion of water was pushed into the cell by slightly opening V3. The experiment proceeded by injecting aliquots of water into the cell and stirring to restore equilibrium. After each injection and equilibration stage, the temperature and pressure of the cell were measured and the cumulative amount of liquid injected calculated. Finally the cell was drained, cleaned and dried to be prepared for the next experimental run.

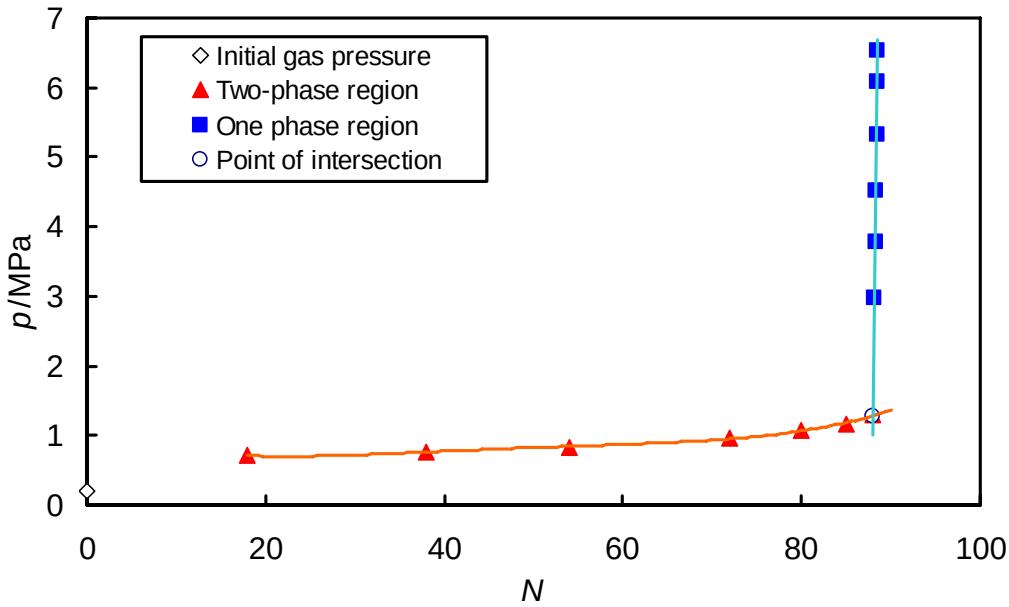


Figure 8.4. Equilibrium pressure p as a function of pump revolutions N for (CO_2 + H_2O) at T = 423 K. The point of intersection between the two-phase branch and the one-phase branch represents the bubble point.

Figure 8.4 is typical plot of the pressure against the pump revolutions and it shows two branches corresponding the two-phase and one-phase regions. The intersection between them corresponds to the bubble point and was determined by curve fitting and numerical solution. At the intersection, we have the bubble-point pressure and, from the initial amount of gas introduced and the cumulative amount of water up to that point, we know the composition. The result comprises one solubility measurement.

The uncertainty in the pressure observed by means of this experimental technique was estimated by the standard deviation of the fit in the two-phase region, assuming in good approximation that the slope of the single-phase branch was infinity. The error in pressure strongly depends on the number of data points used and the quality of the fit. It is estimated to lie between 0.5 % and 5.0 %. The uncertainty in the mole fraction depends on both the uncertainty in the amount of substances of the gas and the water. It is found to be in the order of 10^{-4}. Further refinement of the technique should permit determination of the bubble pressure to better than 1%.

A number of minor issues and two major experimental problems seriously limited the amount of data gathered for (SO_2 + H_2O). The first major problem was one of material compatibility: aqueous solutions of SO_2 are highly corrosive, especially at elevated temperatures. The stainless-steel o-ring initially used was plated with gold-on-silver and, as it turned out, the gold plating was insufficient to prevent chemical attack of the underlying silver layer. Replacement rings (with gold plated directly on to the stainless steel) did not arrive in time and the only available sealing solution was a Viton rubber o-ring. The second problem was that the liquid pump developed a fault and had to be replaced by another unit of smaller capacity. These problems caused the loss of about one month.

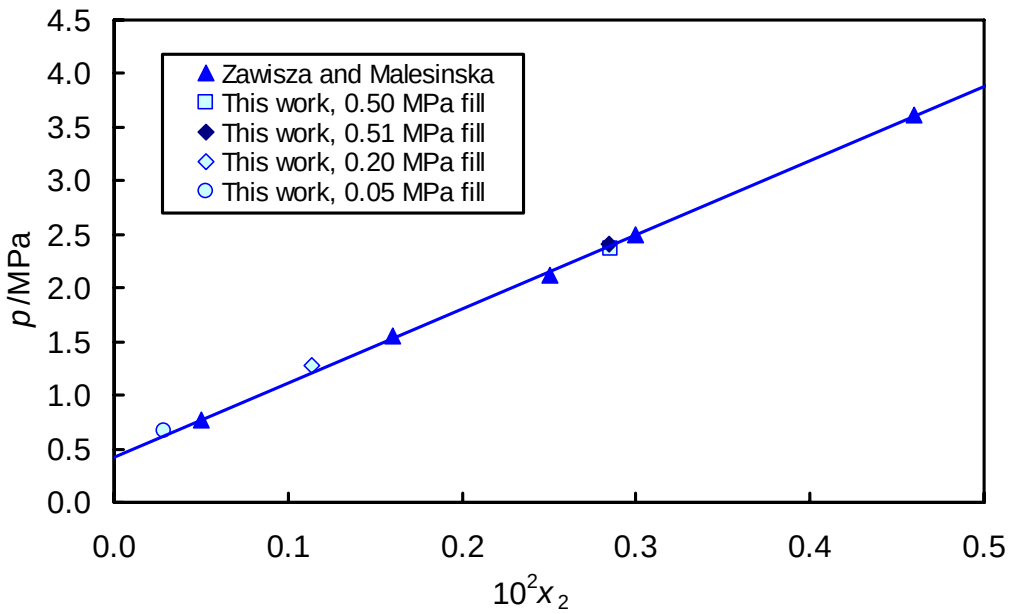


Figure 8.5. Solubility data for (CO_2 + H_2O) at T = 423 K: pressure p as a function of mole fraction x_2 of dissolved gas at the bubble point

8.3.4 Experimental Solubility Results

Experimental solubility data was gathered on (CO_2 + H_2O) at T = (323 and 423) K. These data serve as validation of the experimental technique. Figure 8.5 shows the results at T = 423 K in comparison with the data of Zawisza and Malesinska [11]. The agreement is generally good and the same situation was found at the lower temperature.

The measurements on (SO_2 + H_2O) were only successful at T = 423 K. This is close to the temperature of interest in the IGSC process and so the data are useful. The result is shown in figure 8.6 in comparison with literature data at lower temperatures [12]. Our measurement significantly improves upon the temperature range of previous work. However, the new results are very limited because of the problems identified.

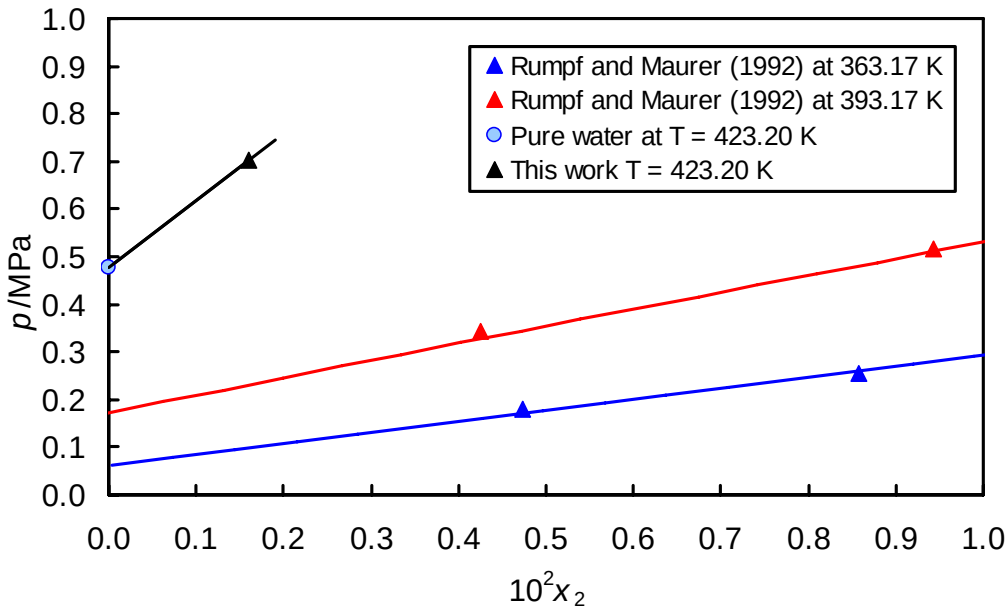


Figure 8.6. Solubility data for (SO_2 + H_2O): pressure p as a function of mole fraction x_2 of dissolved gas at the bubble point.

8.4 The Acid Dew Point

The aim of this part of the study was to estimate of the dew point of flue gases containing traces of sulphur trioxide (SO_3) at elevated pressures. The dew point of these acid flue gases depend strongly on the concentration of sulphur trioxide produced at high temperatures. However, the mole fraction of sulphur trioxide is not determined only by thermodynamic considerations, but also by the kinetics of the formation reactions. Unfortunately, kinetic and other dynamic details of the oxidation of sulphur dioxide (SO_3) in the burner are not known. Therefore, the mole fraction of SO_3 and the dew temperature have been estimated on the basis of thermodynamic data together with simplifying assumptions about the kinetics involved. In particular, the conversion of SO_2 to SO_3 was estimated in two alternative ways: first, assuming that the composition is that of

an equilibrium mixture at the specified burner temperature; and, second, assuming a fixed 6% conversion. Equilibrium calculations were made for syngas/oxygen burner feeds containing different amounts of excess oxygen, over representative ranges of burner temperature and pressure. For burner temperatures in the range (1620 to 1870) K and excess oxygen in the range (0.5 to 2)mol%, the mole fraction of S(VI) species was found to be (0.5 to 26) ppm, increasing with decreasing temperature, increasing pressure and increasing oxygen excess.

In the second part the study, the dew point of the gas was estimated by means of an approach proposed by Bosen and Engels [13] in which it is assumed that, at temperatures below about 500 K, SO_3 is converted completely to molecular sulphuric in the gas phase. The dew curves were then determined from an NRTL-Electrolyte model together with an assumption of gas-phase ideality. Isobaric curves of the dew temperature were calculated at eight different pressures in the range (0.1 to 1.4) MPa for mole fractions of S(VI) in the range (0 to 1000) ppm. Dew pressure curves at constant S(VI) content were also plotted for temperatures between (340 and 540) K. Assuming that the quenched flue gas leaving the burner contained 0.18% SOx, 84% steam and the balance CO_2/inerts on a molar basis, and further assuming 6% conversion of SO2 to SO3, we find a dew temperature of 516 K at a pressure of 1.0 MPa. This is some 70 K higher than found in the absence of S(VI). Figure 8.7 shows the results of the model for various conditions.

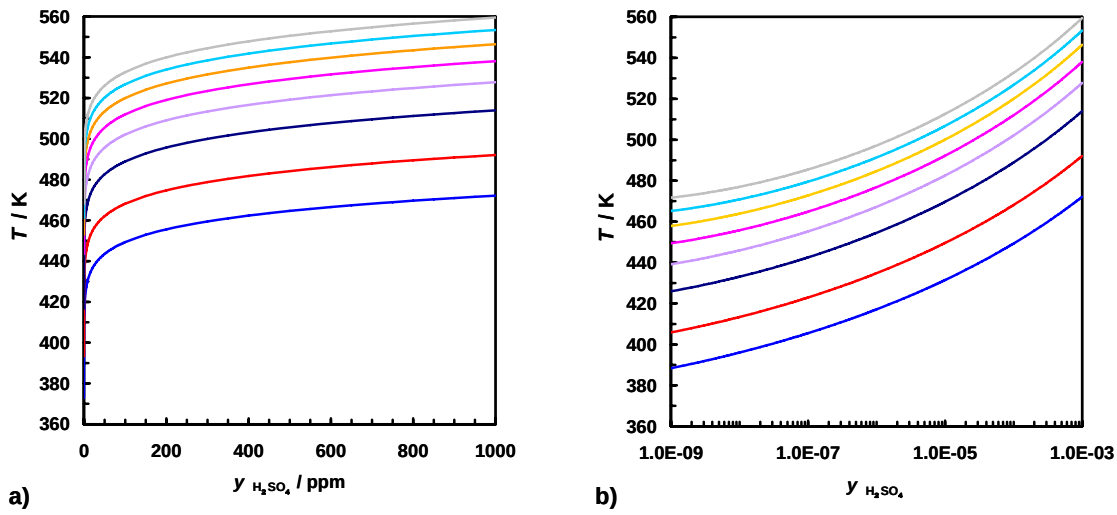


Figure 8.7. Model calculations on the combined phase and chemical equilibria of the binary system water + sulphuric acid: Dew temperature T as function of $y(H_2SO_4)$ at different

pressures. Curves at (—) p = 0.1 MPa, (—) p = 0.2 MPa, (—) p = 0.4 MPa, (—) p = 0.6 MPa, (—) p = 0.8 MPa, (—) p = 1.0 MPa, (—) p = 1.2 MPa, (—) p = 1,4 MPa. a) Linear scale including point at $y(H_2SO_4) = 0$; b) logarithmic scale.

8.5 Conclusions Relating to Physical and Chemical Properties

This study has covered several key areas of modelling and experiment and the results obtained will assist in further development of the IGSC process. Detailed reports on the literature surveys and numerical modelling have been prepared and furnished to the project partners. Further solubility measurements on (SO_2 + H_2O) are needed and it hoped that these can be undertaken in the neat future. The limited results obtained prove the experimental technique and provide new data for (SO_2 + H_2O) that should be used to tune the NRTL-electrolyte model in future process simulation work.

9.0 CONCLUSIONS AND RECOMMENDATIONS

This section discusses the process and commercial results of the project; compares them with what other technologies have to offer; discusses the risks; makes suggestions for further development and R&D; and puts forward an exploitation plan.

9.1 Discussion of Results

Introduction

The development of the IGSC process is built around an all encompassing AspenTech computer simulation model and this model is proprietary to Jacobs.

The main philosophy of oxyfuel for power generation together with CO_2 capture is simple and clear. Carbonaceous fuel is combusted with a mixture of pure oxygen and inert gas which replaces the normal nitrogen contained in air.

There are two versions:

1. Atmospheric combustion of coal using a mixture of oxygen and recycled CO_2
2. Pressurised combustion using a preliminary gasification stage to convert the coal to syngas followed by combustion of the syngas using a mixture of oxygen and recycled water.

The IGSC development explores the second of these versions.

The development starts with the general philosophy of:

- Gasification
- Combustion
- Conversion of the released heat energy to electric power, and
- Separation of the spent steam and CO_2 gas mixture.

Several innovations were necessary to bring this general philosophy into commercial reality. Some of these were decided at the onset, others were necessary to maintain the general philosophy of using as much as possible already commercially proven equipment, and a significant number of others were original inventions made possible by the detailed synergetic expertise and experience available within the Consortium Team.

These innovations are what make the process work, and why and how they had to be developed is discussed below.

These are listed roughly in calendar order although several had to be developed in parallel in order to be able to progress to the next stage of the flow scheme.

High Back-End Pressure

It was noted at the beginning of the work that pressurised water cooled oxy-fuel schemes normally removed the maximum possible energy from the steam/CO_2 mixture by condensing to vacuum conditions. This involves a special type of condensing system designed to accept up to 20% non-condensable gases e.g. CO_2.

These types of condensers are used in the recovery of energy from geophysical occurring steam vented from the Earth, known as “isothermal condensers”. The amount of non-condensable gas contained in a geothermal resource affects the design considerations for an efficient and cost effective power plant. Application following an oxyburner cooled with water means designing to cope with a non-condensable content of 20% i.e. CO_2. The normal non-condensable content of geothermal steam is less than 10% and often less than 5%.

A vacuum geothermal condenser for the intended process would be large and very expensive.

More importantly, the cost and energy requirements for compressing the by-product CO_2 from sub-atmospheric pressure to 100 bar would be very high.

It was therefore decided to run the backend pressure sufficiently high to be able to recover the heat from the condensing steam by other means. A “desaturating” system developed by Jacobs for chemical plants using steam methane reformers was adapted such that the recovered sensible and latent heat would be of sufficient quality to be used in the raising of LP steam.

The system is built around a “Desaturator” vessel in which the close-to-dewpoint steam/CO_2 mixture passes up against a counter-current flow of cold water. The hot water leaving the bottom of the Desaturator is cooled in raising LP steam and recycled to the top of the vessel.

The operating pressure was surmised as 10 bar, thus reducing the cost of compression of the CO_2 to 100 bar by a factor of 5 and the energy requirement by a factor of 2.

Single Stage Expansion

The general principle for converting the heat energy from the oxyburner into rotary power for power generation electricity was generally accepted as driving an expansion turbine. The CES burner is capable of producing the 80% steam 20% CO_2 mixture at very high temperatures and pressures. The initial intention was to combust at as high as possible combination of high temperature and pressure, and then pass the mixture down a series of expansion turbines with further Inter-stage oxyburning reheat as appropriate.

However the philosophy of using as much as possible commercially proven equipment effectively limited the expansion inlet conditions to a combination of 600°C temperature and 270 bar pressure. These are the conditions for frontier technology supercritical steam turbines and would have enabled a second reheated expansion from say 60 bar down to the 10 bar of the Desaturator.

But the 700°C / 350 bar steam turbine is not expected to be available before 2015 and there is no evidence of any development for a high temperature i.e. above 600°C inlet medium pressure steam turbine.

This combination was therefore considered disappointing in requiring a lot of development by others and it was decided instead to consider a single expansion system which could take full advantage of the very high temperatures made possible by the CES burner.

This meant adapting a gas turbine fitted with an expander cooling system, rather than an uncooled steam turbine, and running the expander at whatever inlet pressure was necessary to provide an exhaust close to 10 bar pressure.

An evaluation of various combinations then took place using the computer model and the final conclusion was that a single stage expansion using a modified gas turbine expander the most promising option.

Multiple Burner Gas Turbine

Confronted with the dual requirement of proven equipment and utility scale design, the Consortium Team realised that the relatively small CES burner would either have to be scaled up considerably. Alternatively, some other means would have to be found for it to release sufficient heat energy to be able to generate over 500 MW.

The extensive operational proving of the 20 MW_{th} CES burner in California was seen as an important reinforcement of the integrity of the system, which also applied to its 200 MW_{th} upgraded version currently under test. It was appreciated that the latter burner is being tested installed in an aeroderivative gas turbine and the team decided to look for a much larger multi burner gas turbine on which to base the design development.

A final choice was the Siemens SGT5-4000F previously known as the V94.3A. This gas turbine has 24 annular natural gas burners using air for combustion. The expander firing chamber would be refitted with 24 x 200 MW_{th} CES burners which would be firing at approximately 75% capacity for the Utility Case and 60 to 65% capacity for the Retrofit Case.

No Sulphur Removal

Coal based IGCC power stations remove sulphur from the syngas after gasification and before its use as a fuel in the gas turbines of the combined-cycle unit.

All commercial bulk sulphur removal systems use direct contact or scrubbing of the syngas with a chemical or physical absorbent. This is a liquid and therefore the removal process takes place at close to ambient temperature. This means that the gasification heat has to be removed prior to sulphur removal as well as the particulate matter (ash) in the syngas.

A great deal of effort has been expended in trying to develop systems which remove both particulates and sulphur at high temperature to obviate the losses resulting from cooling down the syngas. The simplest and most efficient way to remove particulates has been found to be through use of a direct water quench. This is particularly advantageous when a high proportion

of steam is required in the syngas for catalytic “shifting” i.e. conversion of carbon monoxide to hydrogen and CO_2. However, even though the shift assists greatly in reducing heat losses, these are still substantial and the sulphur still needs removing.

All these alternatives were examined in detail using the computer model and found wanting:

- The gasifiers could be fitted with boilers or syngas coolers to reduce the temperature of the syngas such that a liquid absorption system could be used to remove the sulphur. But the steam raised represented heat taken out and bypassing the downstream CES burner and expander system with a consequent loss in operating efficiency.
- A catalytic shift was irrelevant as all the gas was going to be combusted to CO_2 in the end anyway.

It was therefore decided to use water quench gasifiers to remove the particulates and to enable all the heat from gasification to be fed into the CES burners in the form of syngas plus steam evaporated from the quench water. Any sulphur removal was left to be carried out at the end of the process from the by-product CO_2.

No Semi-Combustion Extraction

Further investigation with the computer model, confirmed that any extraction of heat or syngas between the two stages of combustion i.e. gasification or partial oxidation and final combustion in the CES burners, reduced overall operating efficiency.

No Condensate Cross- Contamination

The process had now developed into an effective back pressurised combined-cycle with a Fired Expander exhausting into a heat recovery system (HRSG) to raise steam for a conventional commercial scale condensing steam turbine.

This gave rise to two types of water condensate; one the CO_2 and SO_2 rich hot condensate from the Desaturator system, and the other the condensate from the condenser of the conventional Steam Turbine.

Novel Coolant

As discussed above under “Single Stage Expansion” it was decided to use a gas cooled gas turbine as the machine from which the Fired Expander would be developed. This was in order to take full advantage of the high temperatures available from the CES burner. However a cooled machine has to have a medium for cooling. This creates a problem of choice in a process where using the normal media (air, nitrogen, steam or perhaps CO_2) would cause problems to stable operation – see Section 3.8.2 “Fired Expander” for details.

As concluded in Section 3.8.2, the final choice of coolant medium was a mixture of steam and CO_2 to i.e. “flue gas”. This fitted comfortably within the total design without additional risk to operating stability. The cooling medium was perfectly acceptable to Siemens, the Fired Expander fabricator, and was a significant innovation in the completion of the process design.

9.2 Comparison with Other CCS Technologies

It is not possible to come to a general conclusion on which is the best process for CCS. It is impossible to find a common ground for comparison. For example, is the basis for comparison to be:

- On the same quantity of CO_2 removed or the same percentage?
- Cost per tonne of CO_2 removed or cost per MW made CO_2-free?
- On maintaining the same net electricity production after removal as before?

- and many other possible bases.

However at 32% including the ASU (see Table 7.6 in Section 7 “Economic Analysis) it can be said that IGSC exhibits a competitive overall efficiency.

The following table is not intended as a means to decide which to show any superior process, any comparison should be done only on a specific case by case basis.

Alternative CCS Processes

		Post Combustion Oxyfuel		Remarks
	Pre-Combustion IGCC	CO_2 Recycle	IGSC Water Recycle	
Coal Preparation	Grind to 200 mesh	Grind to 200 mesh	Grind to 200 mesh	Wet or dry feed
ASU	40%	100%	100%	99.5% Oxygen
Shift System	Yes	No	No	
AGR	Two Stage	FGD	With CO_2 Compression	
Power Generation	Combined Cycle	Single Cycle	Combined Cycle	
CO_2 Compression	From Atmospheric	From Atmospheric	From 10 bar	100 bar export
Stack	Yes	No	No	
Capture Capability	90%	100%	100%	
CO2 Purity	97%		98%	

Flue Gas Scrubbing Excluded

1

Table 9.1 Alternartive CCS Processes

9.3 Risks

The HSE risks are discussed in Section 3.11. This section briefly discusses the development risks and highlights the challenges required to be overcome in order to bring this new concept to the market.

Commercial

Commercial risks only become relevant when the process has been developed to the point when it can be considered for enactment as a project development. At this stage, the risks to be identified and countered are those associated with the technology and specialist equipment.

Technology

With the exception of the following issues none of the proposed technology exhibits any new or excessive risk:

- A reliable data base to predict the acid and water dewpoint temperatures in the post-HRSG cooling train.
- The intra-plant control of sulphur and its eventual removal from the by-product CO_2.
- Suitable materials of construction for acid and water condensing regions and for acid condensate pumps and pipework

Equipment

With the exception of two key items of equipment none of the equipment is considered to exhibit any significant new or excessive risk. These items are the Fired Expander and the HRSG. Even so the Fired Expander is a derivative from a well proven gas turbine. It has been examined in detail by Siemens who are confident that nothing will exceed already experienced and well-known operating conditions and intend to be able to offer guarantees once their design and development work has been completed.

Similarly the potential suppliers for the HRSG have examined this item in detail. They are confident that the design conditions reside entirely within their experience and they also intend to be able to offer guarantees once their design and development work has been completed.

Nevertheless these risks have not yet been experienced in combination in the same plant, nor does the scale of the HRSG fall within the normal range of fabrication of such equipment. It is therefore strongly recommended that before any commitment is made to commence design of a full scale plant, a pilot demonstration plant should be built and operated within which many of these risks can be examined in combination.

It is also recommended that a program of research and development be instigated for examination and gathering of data regarding the process conditions and reactions.

This is discussed below under 9.4.1

9.4 Future Development

9.4.1 Further R & D

It is recommended that at least three separate R & D Programs should be launched in connection with the further commercialisation of the IGSC process as follows:

1. Compilation of physical data for steam/CO_2/SO_2 mixtures at combinations of temperatures and pressures pertaining to the process and especially in the regions of acid and water dewpoint temperatures.

2. A full investigation of the Air Products SO_2 removal system and its suitability to incorporate within the CO_2 compression system.

3. A detailed search for suitable materials of construction for all those regions identified as the physical data work under task (1) above proceeds.

9.4.2 Intellectual Property Rights (IPR)

As described in the previous pages of the report, more than seven discreet innovations were developed during the course of the work and a number have gone on to become the subject of patent applications.

The Consortium Collaboration Agreement makes it clear that any IPR brought by a Member to the Project work or invented by a Member during the course of that work belongs to that Member and shall not be unduly withheld for exploitation in a commercial project by any other Member.

For application of the technology outside of the UK, prior reference will be made to BERR.

9.4.3 Potential Markets & Exploitation Strategy

It is considered essential that the preliminary single design carried out during this project is validated and optimised to take full advantage of the innovations which have been developed and put together in what is so far a single enactment. The process designers feel strongly that there is room for improvement, and the best time to take advantage of that potential improvement is now, while the original work is still fresh.

It is also considered self evident that once the promise offered by this new process is confirmed, then the market potential is global and very large.

Above all the Demonstration/Industrial scale plant needs to be built and operated as described in Section 4.6 in order to provide the confidence to potential investors that the process has been properly investigated before proceeding to its full commercial potential.

The Consortium has already developed a scheme for such a plant with the intention that it shall be commercially attractive in its own right by selling into areas where not only relatively small scale power is required but also relatively large quantities of CO_2 for EOR.

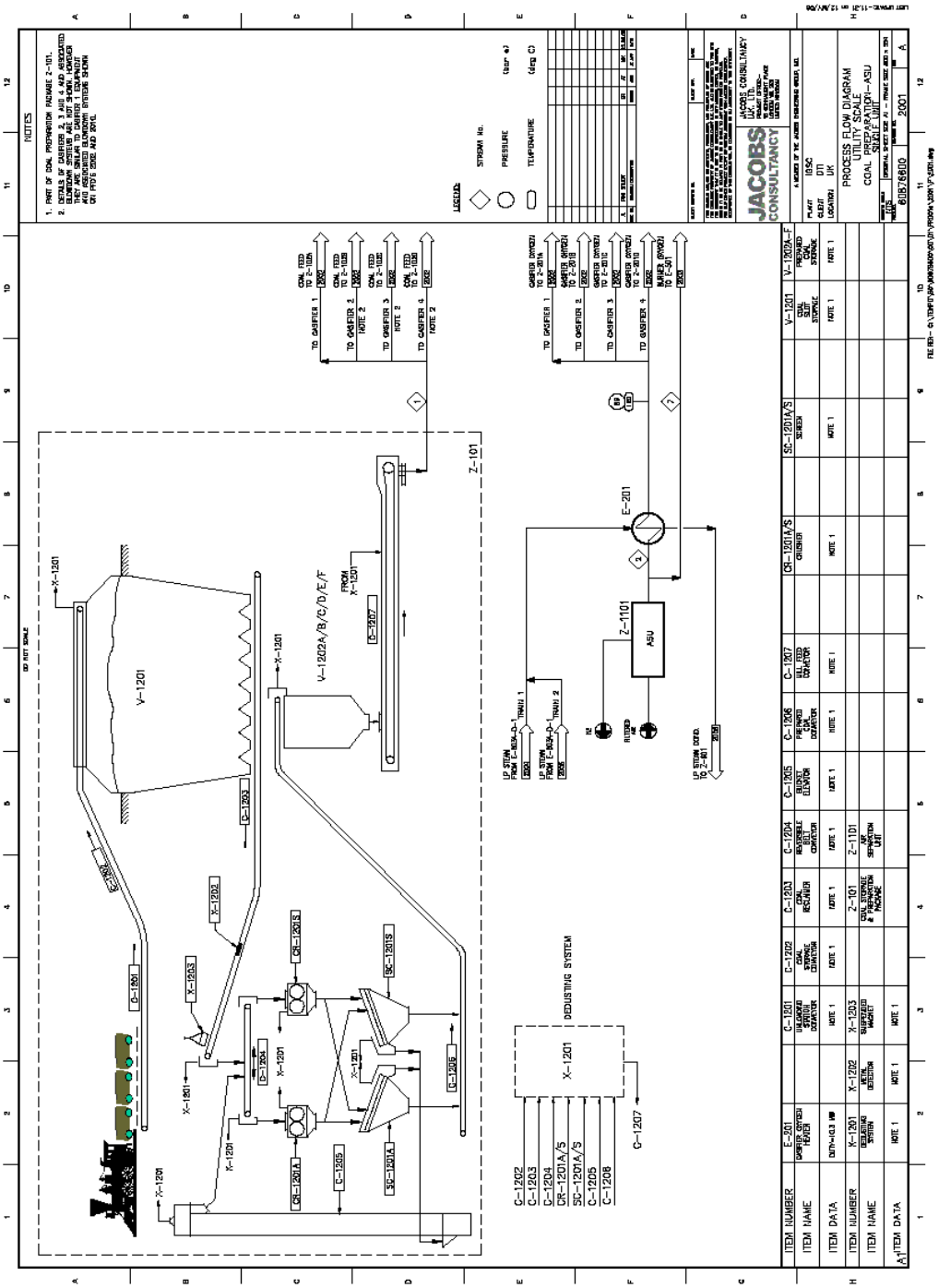
Three areas of opportunity have been identified:

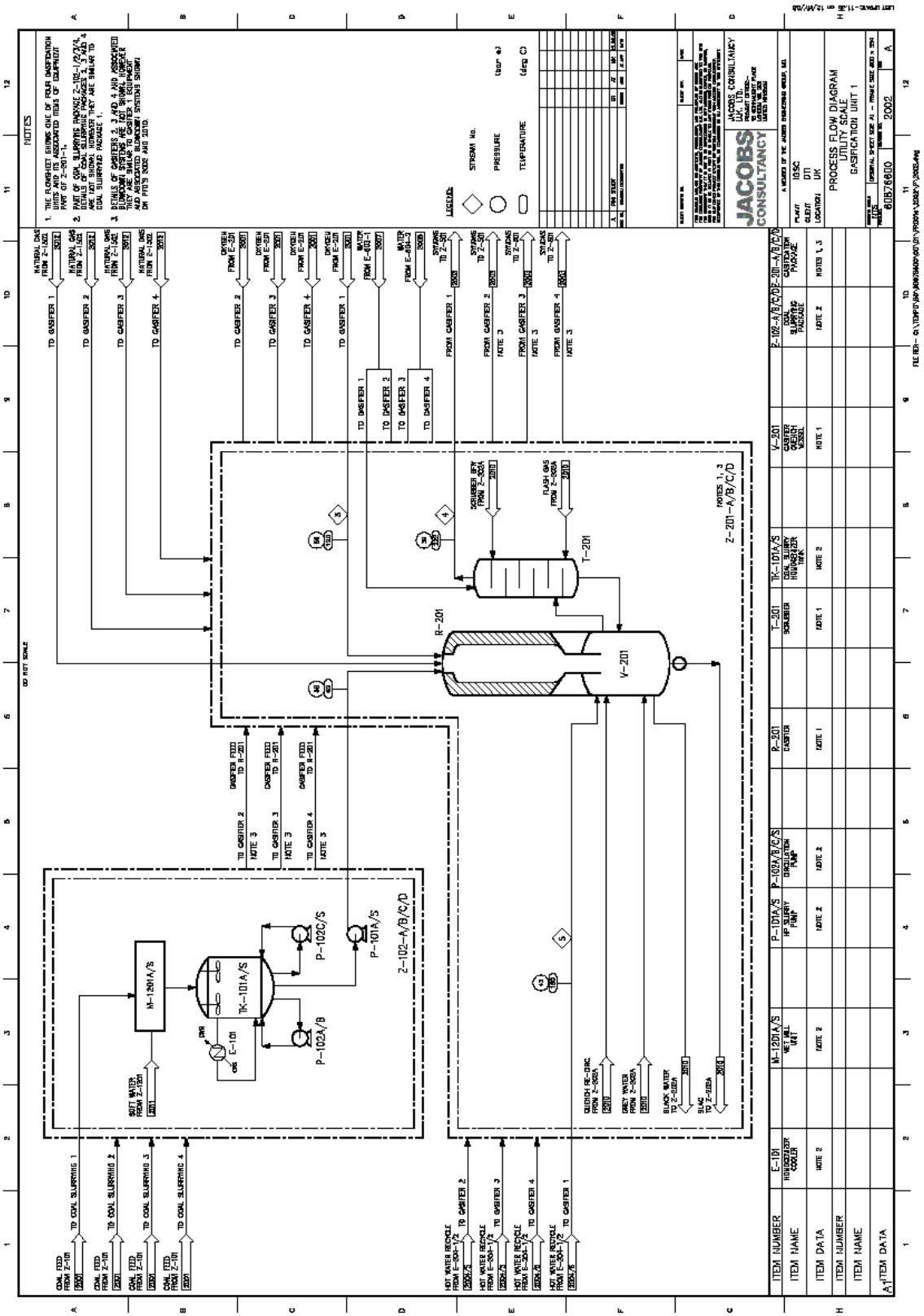
- In California where CES are already building such a plant running on natural gas
- In Norway where the main requirement is the power with the CO_2 being sent to storage, and
- In oil producing areas where the CO_2 would be beneficial and the bonus of a side product of water would be most welcome such as the Permian Basin in West Texas and Louisiana, the Gulf Coast, and the Middle East.

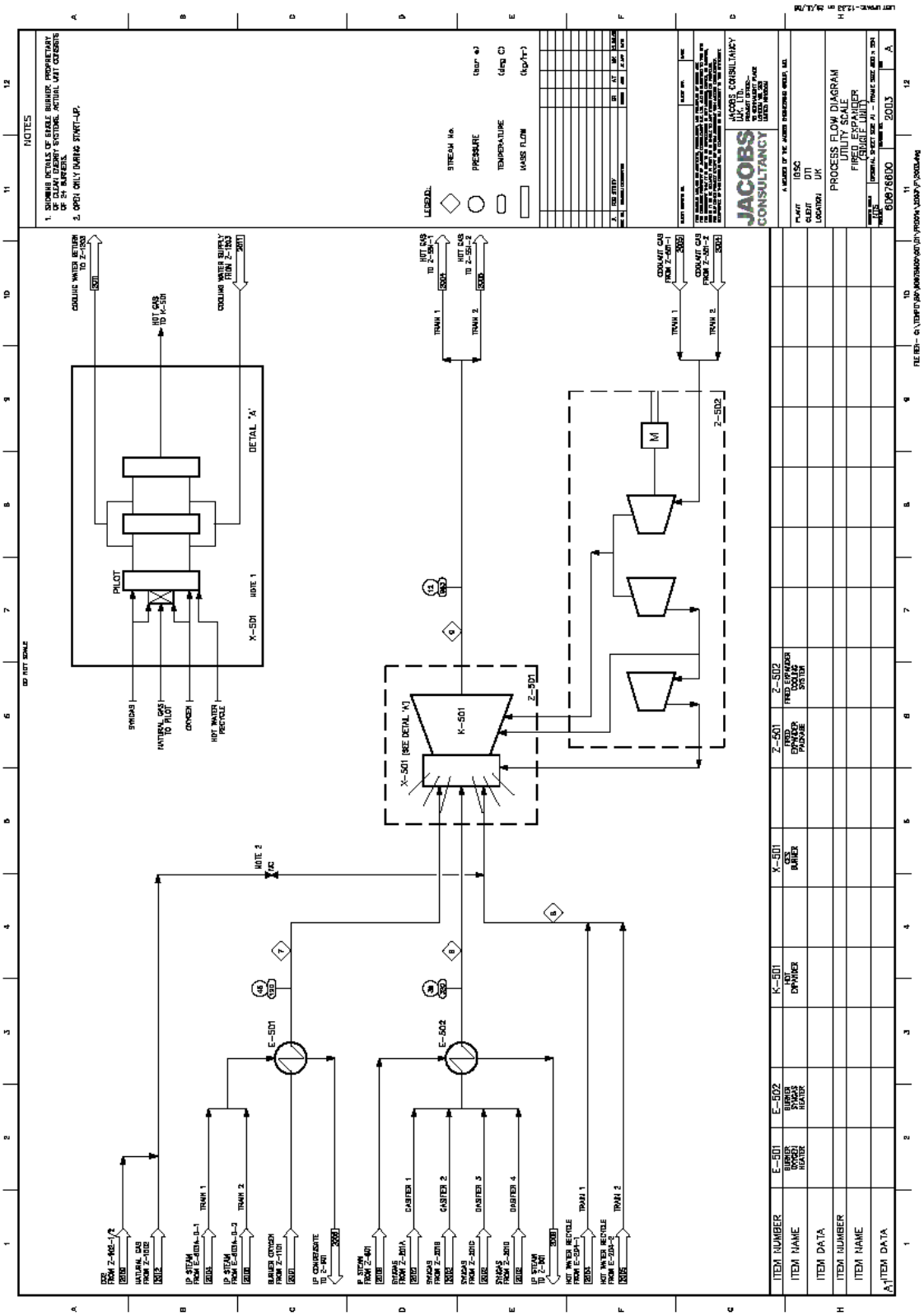
  In the meantime the Consortium is ensuring that the process is given extensive publication by presenting papers at international conferences, and through detailed articles in globally circulated technical magazines

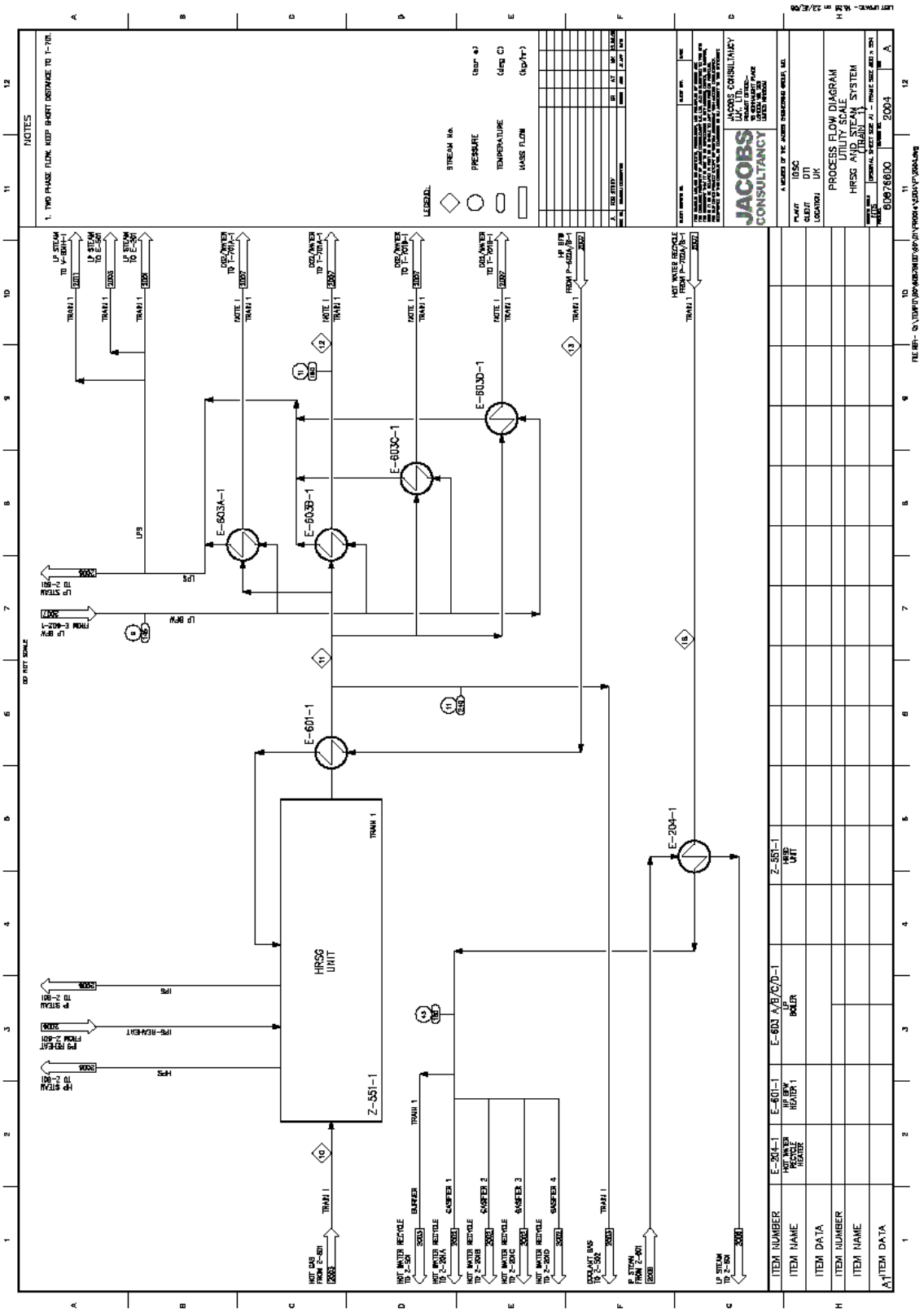
APPENDIX A – PFD

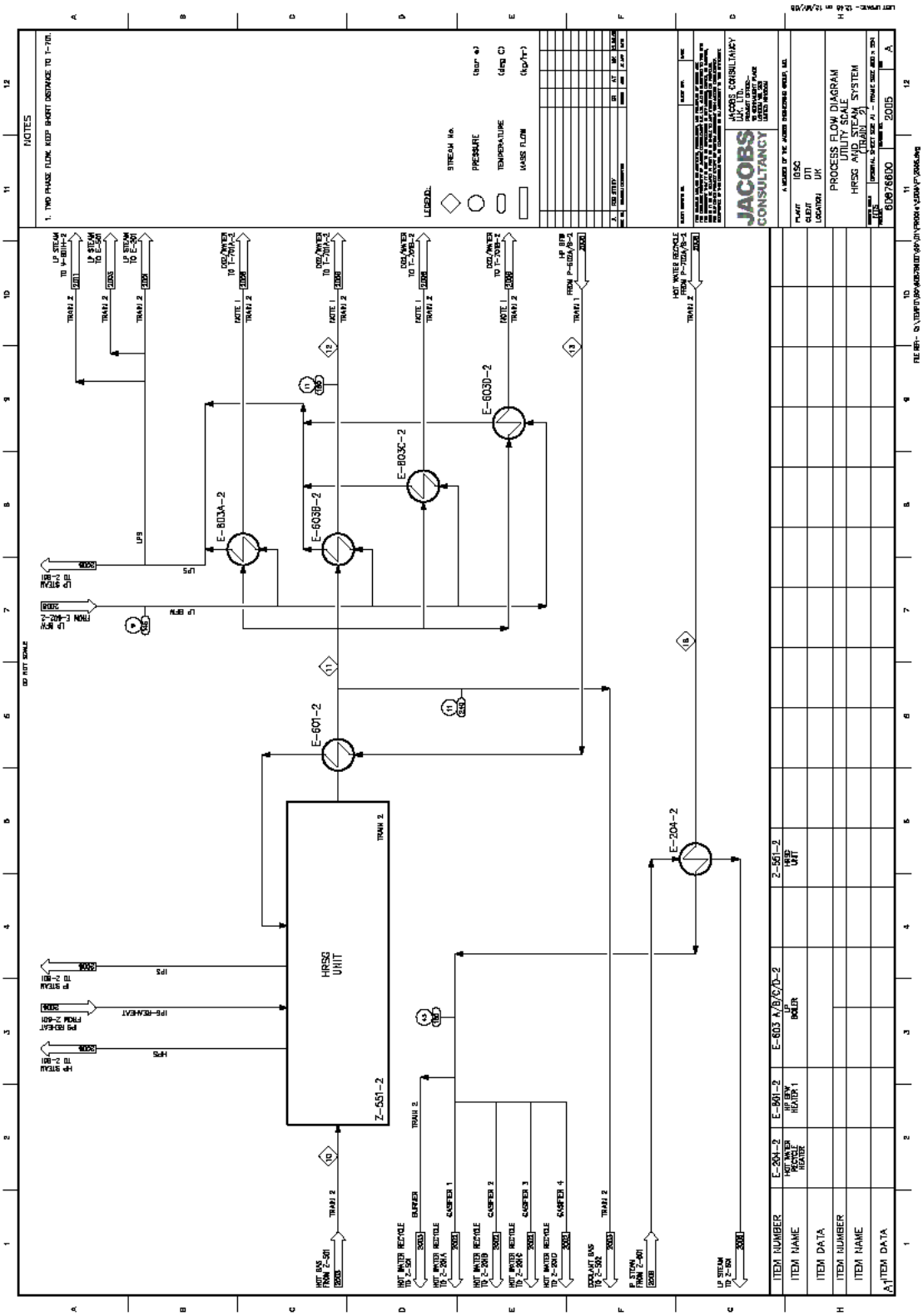
A1 Utility Case PFDs

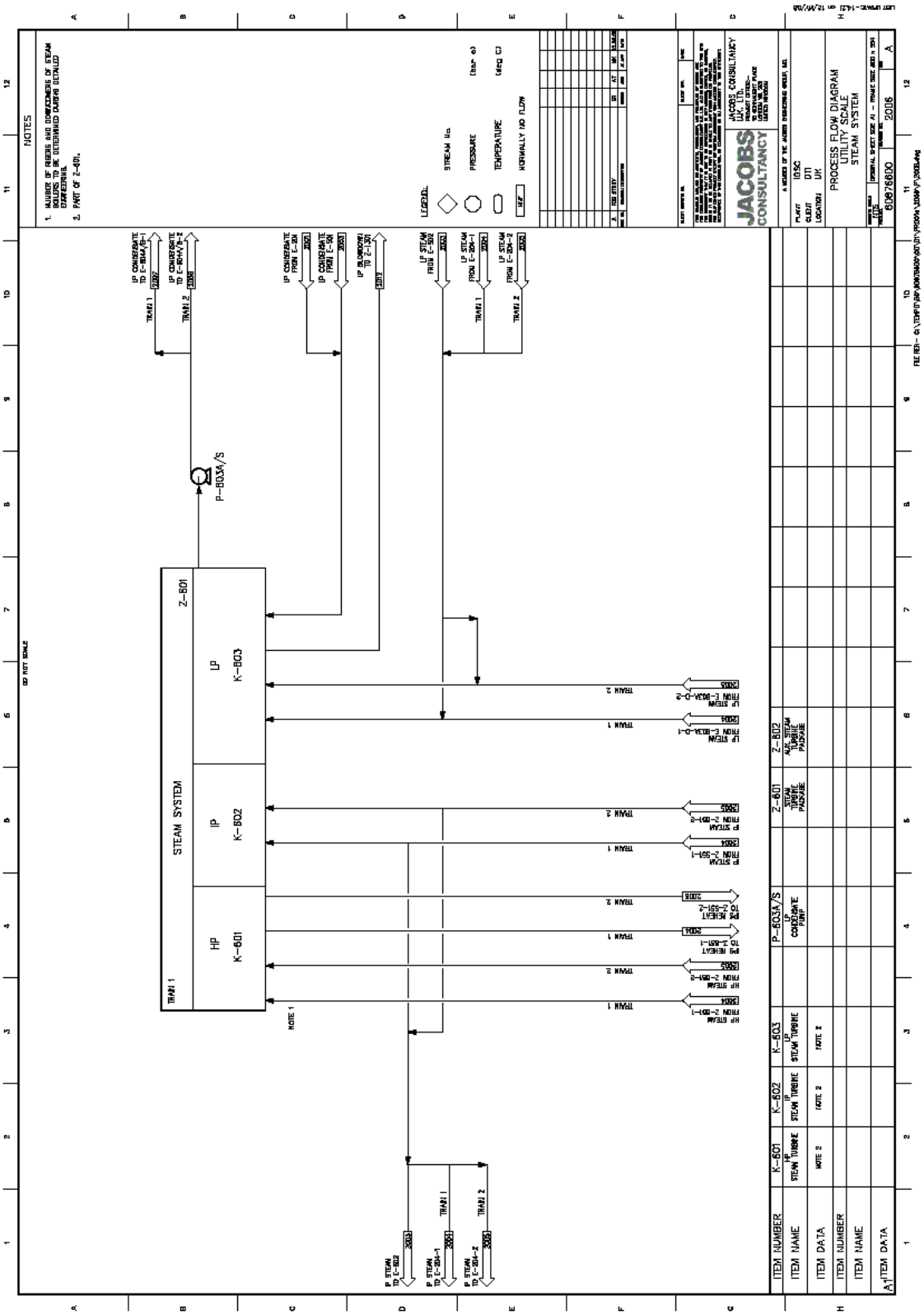


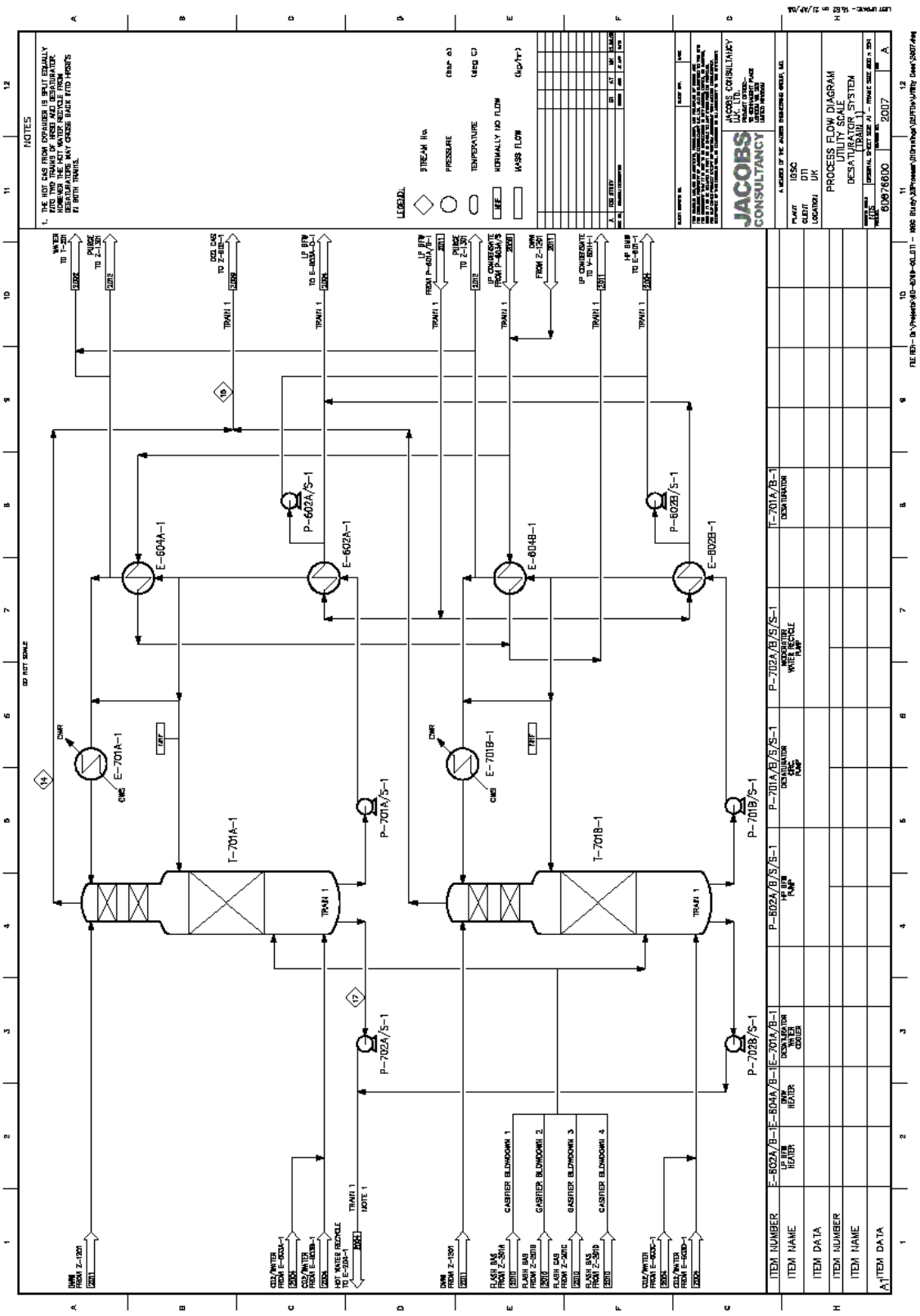

NOTES
1. THE FLOWSHEET SHOWS ONE OF FOUR GASIFICATION UNITS AND ITS ASSOCIATED ITEMS OF EQUIPMENT PART OF Z-201-A/B/C/D.
2. FOUR OF COAL SLURRYING PACKAGE Z-102-A/B/C/D, ITEMS OF COAL SLURRYING PACKAGE Z-102-A/B/C/D, ARE NOT SHOWN. HOWEVER THEY ARE SIMILAR TO COAL SLURRYING PACKAGE 1.
3. DETAILS OF GASIFIERS 2, 3 AND 4 AND ASSOCIATED BLOWDOWN SYSTEMS ARE NOT SHOWN. HOWEVER THEY ARE SIMILAR TO GASIFIER 1 AND ASSOCIATED BLOWDOWN SYSTEMS SHOWN ON PFD'S 3002 AND 3010.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
UTILITY SCALE
GASIFICATION UNIT 1
6U576600
2002
A
ITEM NUMBER
ITEM NAME
ITEM DATA
ITEM NUMBER
ITEM NAME
ITEM DATA

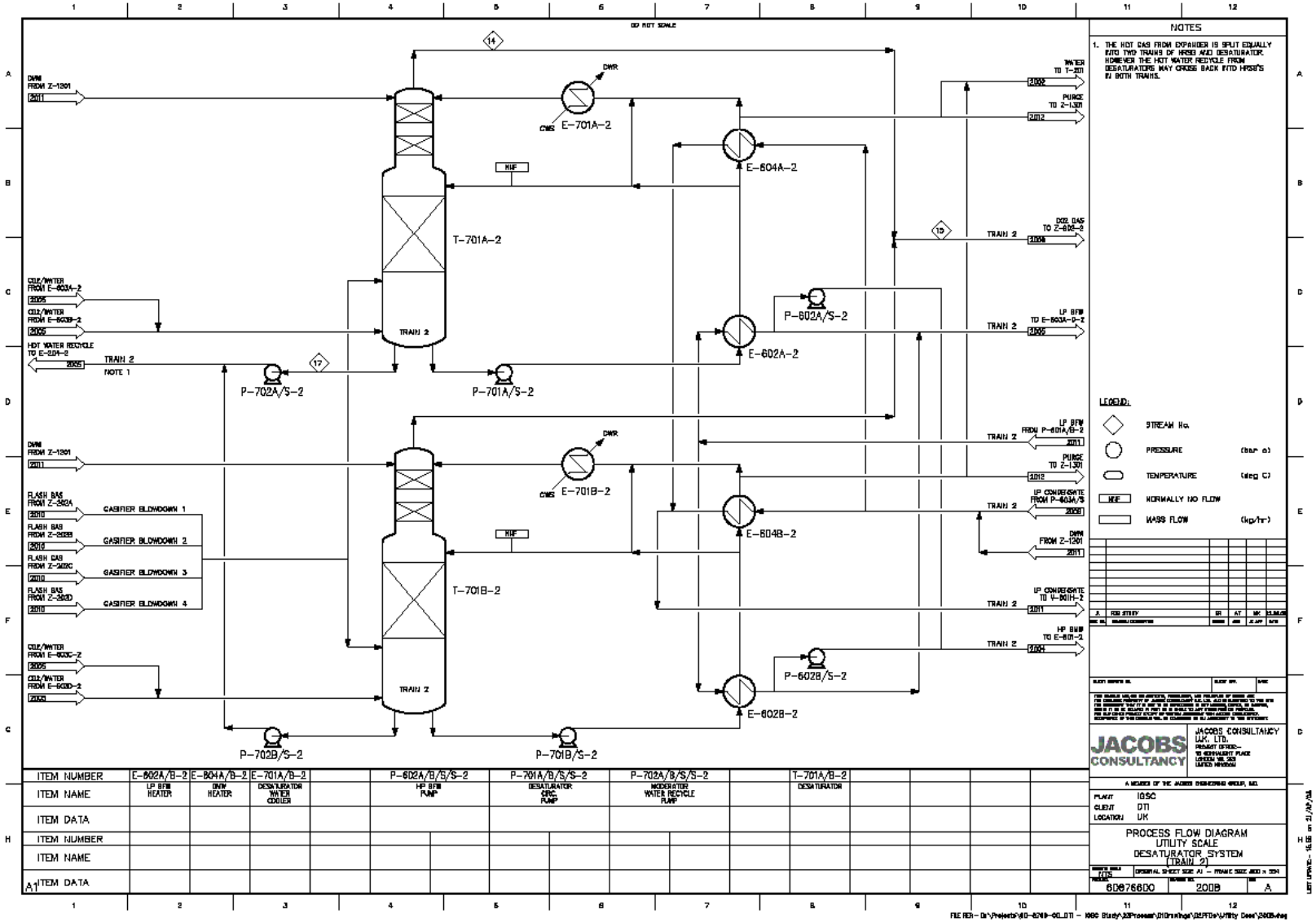

NOTES
1. SHOWING DETAILS OF GAGLE BURNER PROPRIETARY OF CLEAN ENERGY SYSTEMS. ACTUAL UNIT CONSISTS OF 24 BURNERS.
2. OPEN ONLY DURING START-UP.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
UTILITY SCALE
FIRED EXPANDER
(SINGLE UNIT)
PLANT ISGC
CLIENT DTI
LOCATION UK
DO NOT SCALE
COOLING WATER RETURN TO Z-1503
HOT GAS TO K-501
COOLING WATER SUPPLY FROM Z-1503
DETAIL 'A'
PILOT
X-501 NOTE 1
SYNGAS
NATURAL GAS TO PILOT
OXYGEN
HOT WATER RECYCLE
HOT GAS TO Z-501-1
HOT GAS TO Z-501-2
TRAIN 1
TRAIN 2
COOLANT GAS FROM Z-501-1
COOLANT GAS FROM Z-501-2
Z-502
M
X-501 (SEE DETAIL 'A')
K-501
Z-501
NOTE 2
E-501
E-502
GASIFIER 1
GASIFIER 2
GASIFIER 3
GASIFIER 4
ITEM NUMBER
ITEM NAME
ITEM DATA
E-501 BURNER OXYGEN HEATER
E-502 BURNER SYNGAS HEATER
K-501 HOT EXPANDER
X-501 GAS BURNER
Z-501 FIRED EXPANDER PASSIVE
Z-502 FIRED EXPANDER COOLING SYSTEM
A1 ITEM DATA
60676600
2003


NOTES
1. TWO PHASE FLOW. KEEP SHORT DISTANCE TO T-701.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
JACOBS CONSULTANCY UK LTD.
PLANT IGSC
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
UTILITY SCALE
HRSG AND STEAM SYSTEM
2004
A
DO NOT SCALE
HRSG UNIT
Z-551-1
E-601-1
E-603A-1
E-603B-1
E-603C-1
E-603D-1
E-204-1
HOT GAS FROM Z-601
HOT WATER RECYCLE TO Z-501
BURNER
GASFIRE 1
GASFIRE 2
GASFIRE 3
GASFIRE 4
DEAD-WIT GAS TO Z-501
P. STEAM FROM Z-601
LP STEAM TO Z-501
HP STEAM TO Z-601
IP STEAM TO Z-601
IP9 REHEAT FROM Z-601
LP STEAM TO Z-501
LP BFW FROM E-602-1
HP BFW FROM P-602A/B-1
HOT WATER RECYCLE FROM P-702A/B-1
ITEM NUMBER
ITEM NAME
ITEM DATA
E-204-1
HOT WATER RECYCLE HEATER
E-601-1
HP BFW HEATER 1
E-603 A/B/C/D-1
LP BOILER
Z-551-1
HRSG UNIT
A1

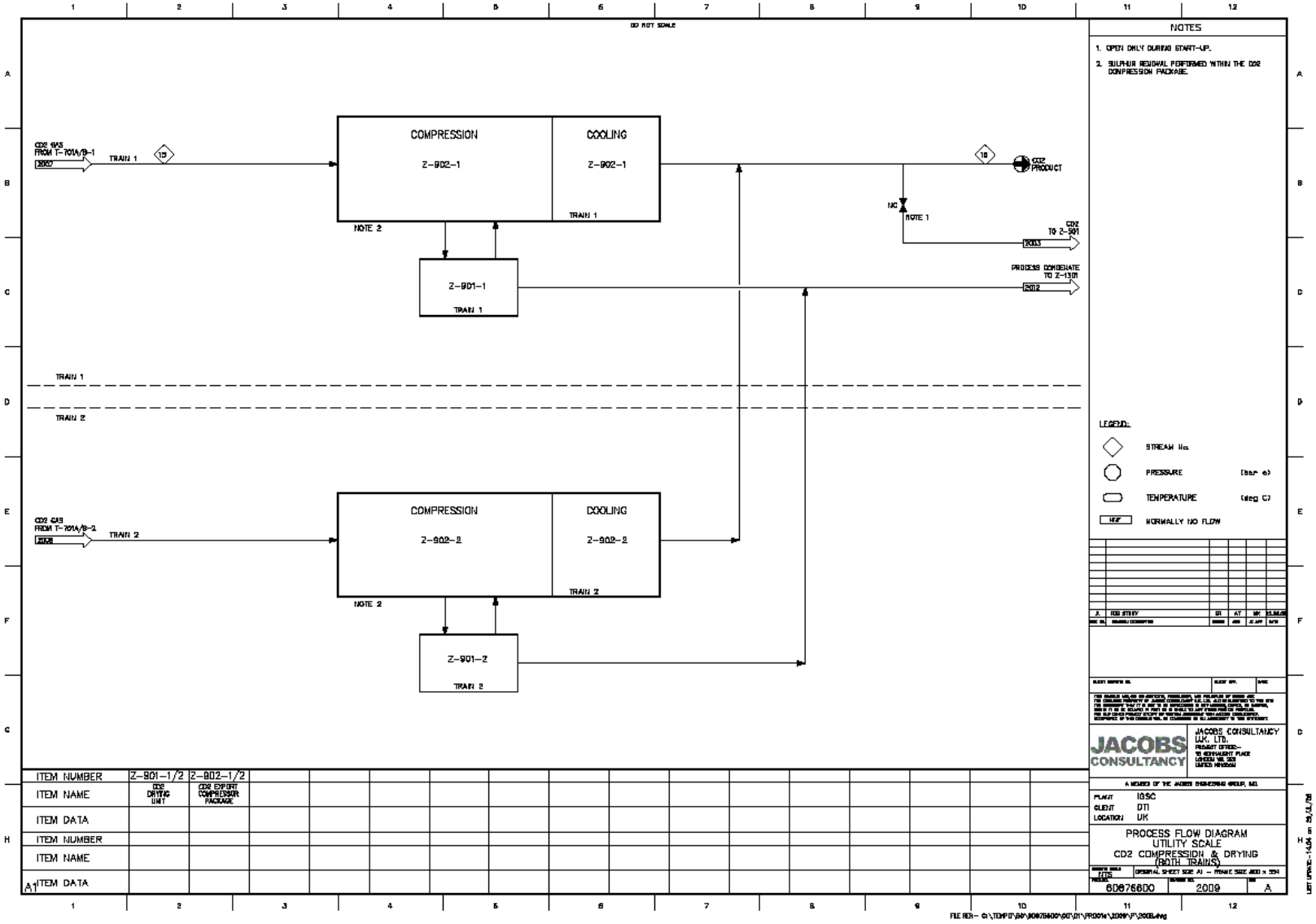

NOTES
1. TWO PHASE FLOW. KEEP SHORT DISTANCE TO T-701.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
UTILITY SCALE
HRSG AND STEAM SYSTEM
(TRAIN 2)
E-601-2
E-603A-2
E-603B-2
E-603C-2
E-603D-2
E-204-2
HRSG UNIT
Z-551-2
ITEM NUMBER
ITEM NAME
ITEM DATA
ITEM NUMBER
ITEM NAME
ITEM DATA

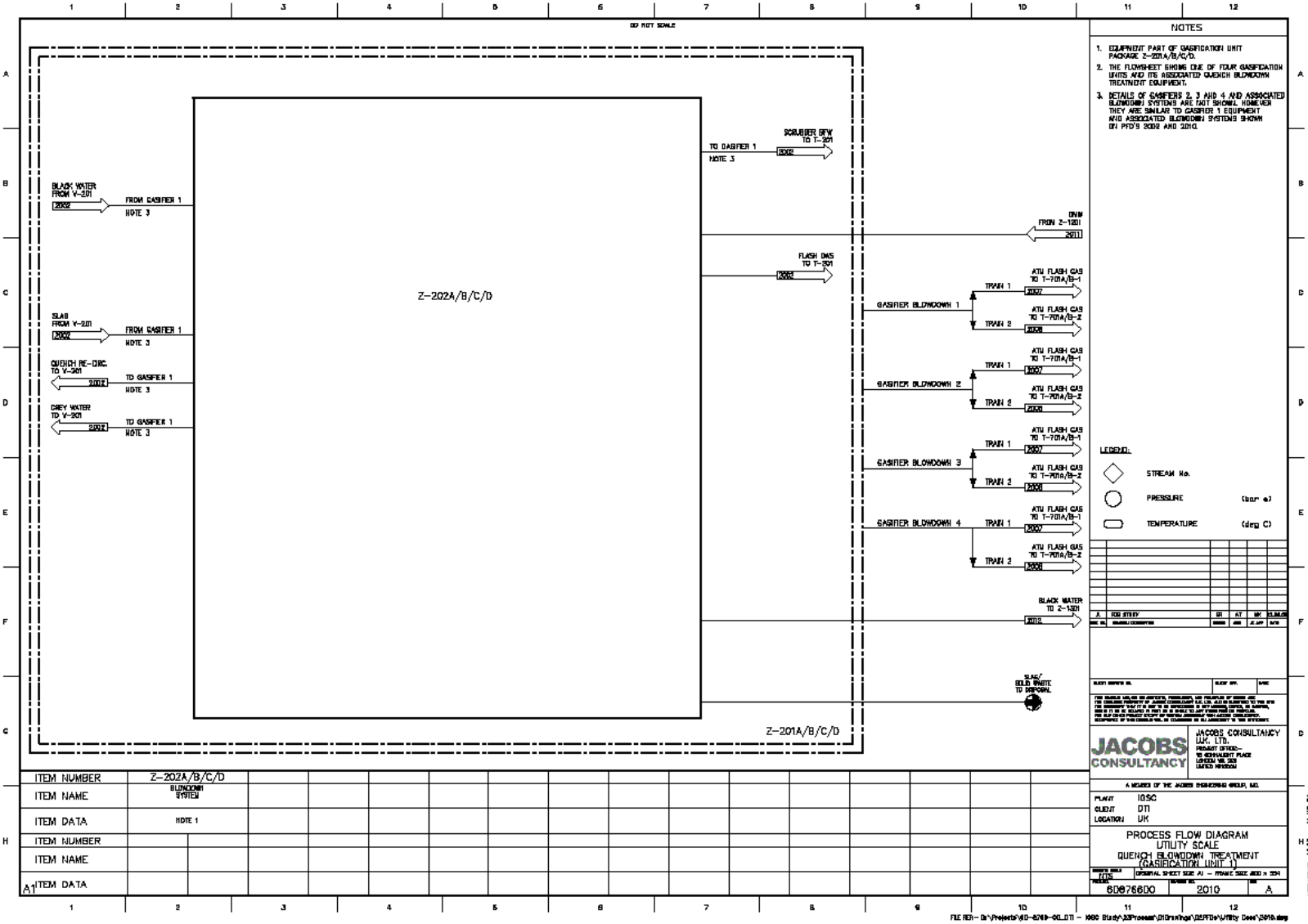

NOTES
1. NUMBER OF FIRERS AND DIMENSIONS OF STEAM BOILERS TO BE DETERMINED DURING DETAILED DESIGN PHASE.
2. PART OF Z-401.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
NORMALLY NO FLOW
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
UTILITY SCALE
STEAM SYSTEM
STEAM SYSTEM
Z-601
TRAIN 1
HP K-601
IP K-602
LP K-603
P-603A/S
NOT TO SCALE
ITEM NUMBER
ITEM NAME
ITEM DATA
K-601 HP STEAM TURBINE
K-602 IP STEAM TURBINE
K-603 LP STEAM TURBINE
P-603A/S LP CONDENSATE PUMP
Z-601 STEAM TURBINE PACKAGE
Z-602 AUX. STEAM TURBINE PACKAGE
2006

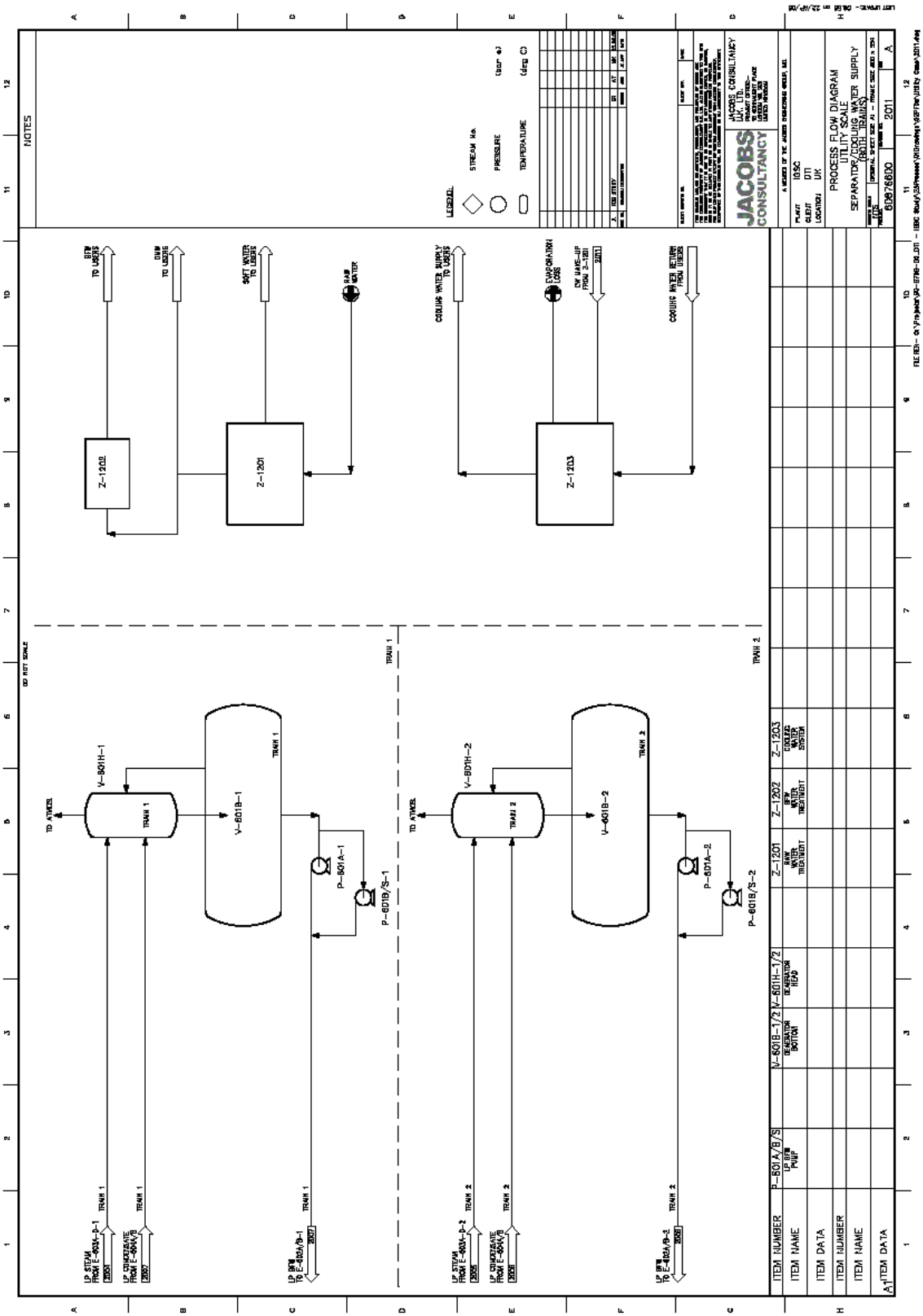

NOTES
1. THE HOT GAS FROM EXPANDER IS SPLIT EQUALLY INTO TWO TRAINS OF DESATURATOR. HOWEVER THE HOT WATER RECYCLE FROM DESATURATORS MAY CROSS BACK INTO HEADERS IN BOTH TRAINS.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
VOLUMETRICALLY FLOW
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
UTILITY SCALE
DESATURATOR SYSTEM
(TRAIN 1)
DO NOT SCALE
T-701A-1
T-701B-1
E-701A-1
E-701B-1
E-604A-1
E-602A-1
E-604B-1
E-602B-1
P-602A/S-1
P-602B/S-1
P-701A/S-1
P-701B/S-1
P-702A/S-1
P-702B/S-1
TRAIN 1
CASTER BLOWDOWN 1
CASTER BLOWDOWN 2
CASTER BLOWDOWN 3
CASTER BLOWDOWN 4
ITEM NUMBER
ITEM NAME
ITEM DATA

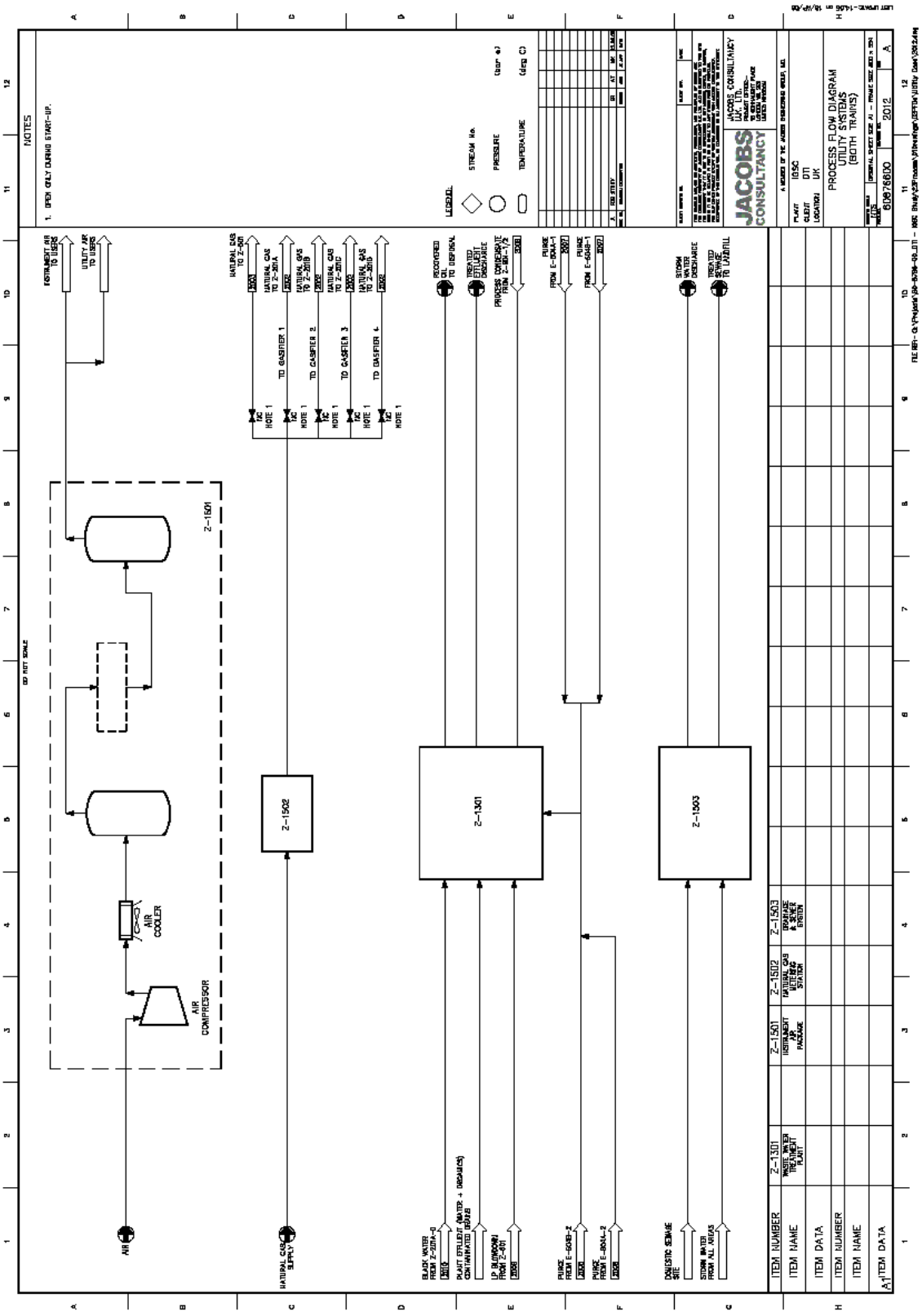

DO NOT SCALE
DWM FROM Z-1301
2011
COLD WATER FROM E-603A-2
2005
COLD WATER FROM E-603B-2
2005
HOT WATER RECYCLE TO E-204-2
2005
TRAIN 2
NOTE 1
P-702A/S-2
P-701A/S-2
T-701A-2
TRAIN 2
E-701A-2
CWR
CWS
E-604A-2
E-602A-2
P-602A/S-2
NWF
WATER TO T-201
2002
PURGE TO Z-1301
2012
CO2 GAS TO Z-605-2
2006
LP BFW TO E-603A-D-2
2005
LP BFW FROM P-601A/B-2
2011
LP CONDENSATE FROM P-603A/S
2008
DWM FROM Z-1301
2011
LP CONDENSATE TO V-801H-2
2011
HP BWW TO E-801-2
2004
FLASH GAS FROM Z-302A
2010
FLASH GAS FROM Z-302B
2010
FLASH GAS FROM Z-302C
2010
FLASH GAS FROM Z-302D
2010
GASIFIER BLOWDOWN 1
GASIFIER BLOWDOWN 2
GASIFIER BLOWDOWN 3
GASIFIER BLOWDOWN 4
COLD WATER FROM E-603C-2
2005
COLD WATER FROM E-603D-2
2005
P-702B/S-2
P-701B/S-2
T-701B-2
TRAIN 2
E-701B-2
E-604B-2
E-602B-2
P-602B/S-2
NOTES
1. THE HOT GAS FROM EXPANDER IS SPLIT EQUALLY INTO TWO TRAINS OF HRSG AND DESATURATOR. HOWEVER THE HOT WATER RECYCLE FROM DESATURATORS MAY CROSS BACK INTO HRSG'S IN BOTH TRAINS.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
NWF NORMALLY NO FLOW
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
JACOBS CONSULTANCY UK. LTD.
PROJECT OFFICE:-
'BS HERMITAGE PLACE
LONDON NW. 10A
UNITED KINGDOM
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.
PLANT IGSC
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
UTILITY SCALE
DESATURATOR SYSTEM
(TRAIN 2)
6D8766DO
2008
A
ITEM NUMBER
ITEM NAME
ITEM DATA
E-602A/B-2
LP BFW HEATER
E-604A/B-2
DWM HEATER
E-701A/B-2
DESATURATOR WATER COOLER
P-602A/B/S/S-2
HP BFW PUMP
P-701A/B/S/S-2
DESATURATOR SPRY PUMP
P-702A/B/S/S-2
MODERATOR WATER RECYCLE PUMP
T-701A/B-2
DESATURATOR

A8

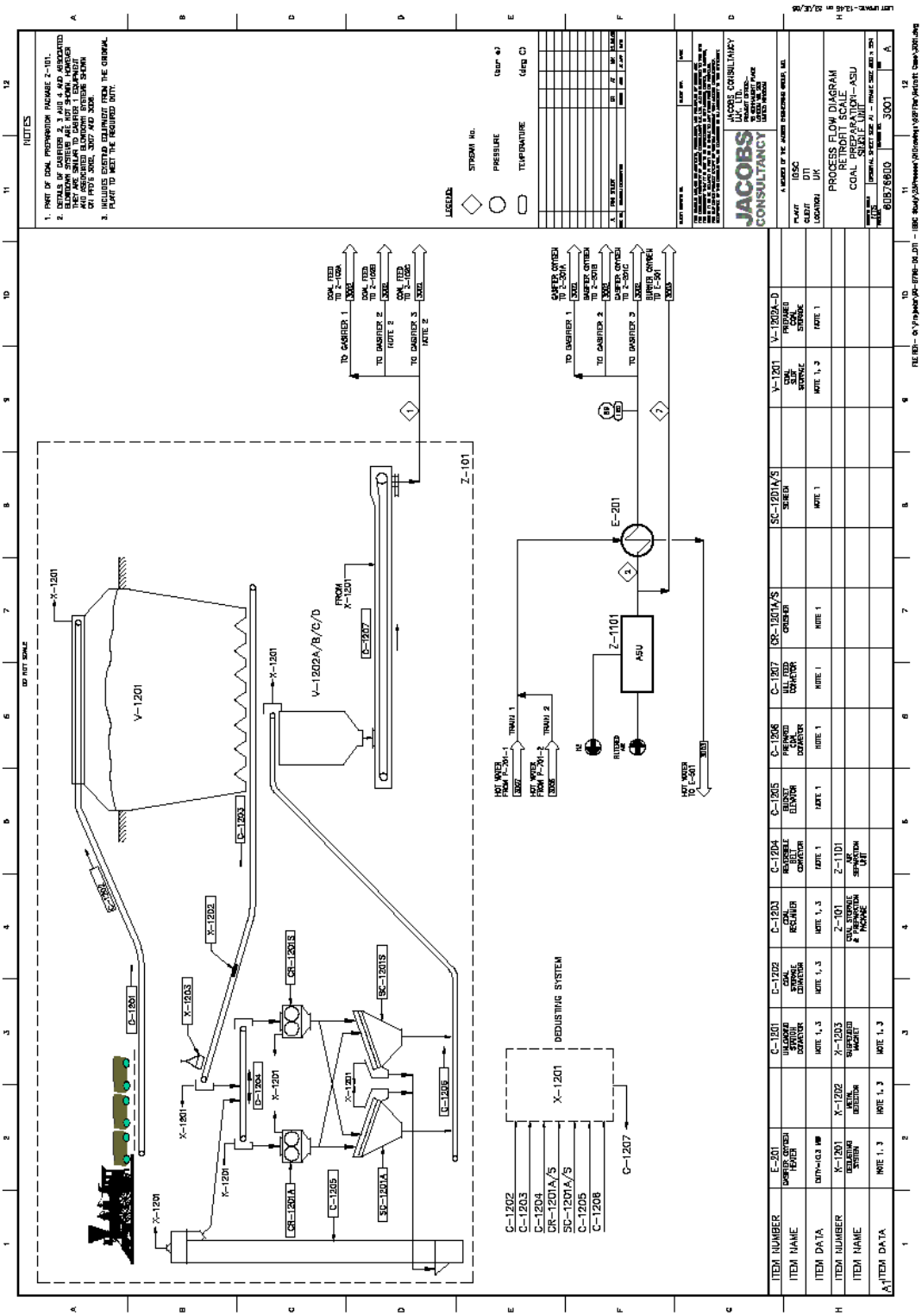

CO2 NOT SCALE
CO2 GAS FROM T-701A/B-1
TRAIN 1
COMPRESSION
Z-902-1
COOLING
Z-902-1
TRAIN 1
NOTE 2
Z-901-1
TRAIN 1
CO2 PRODUCT
NC
NOTE 1
CO2 TO Z-901
PROCESS CONDENSATE TO Z-1301
TRAIN 1
TRAIN 2
CO2 GAS FROM T-701A/B-2
TRAIN 2
COMPRESSION
Z-902-2
COOLING
Z-902-2
TRAIN 2
NOTE 2
Z-901-2
TRAIN 2
NOTES
1. OPEN ONLY DURING START-UP.
2. SULPHUR REMOVAL PERFORMED WITHIN THE CO2 COMPRESSION PACKAGE.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
NORMALLY NO FLOW
JACOBS CONSULTANCY
JACOBS CONSULTANCY UK. LTD.
PLANT IGSC
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
UTILITY SCALE
CO2 COMPRESSION & DRYING
(BOTH TRAINS)
6087660D
2009
A
ITEM NUMBER
Z-901-1/2
Z-902-1/2
ITEM NAME
CO2 DRYING UNIT
CO2 EXPORT COMPRESSOR PACKAGE
ITEM DATA
ITEM NUMBER
ITEM NAME
ITEM DATA
A1

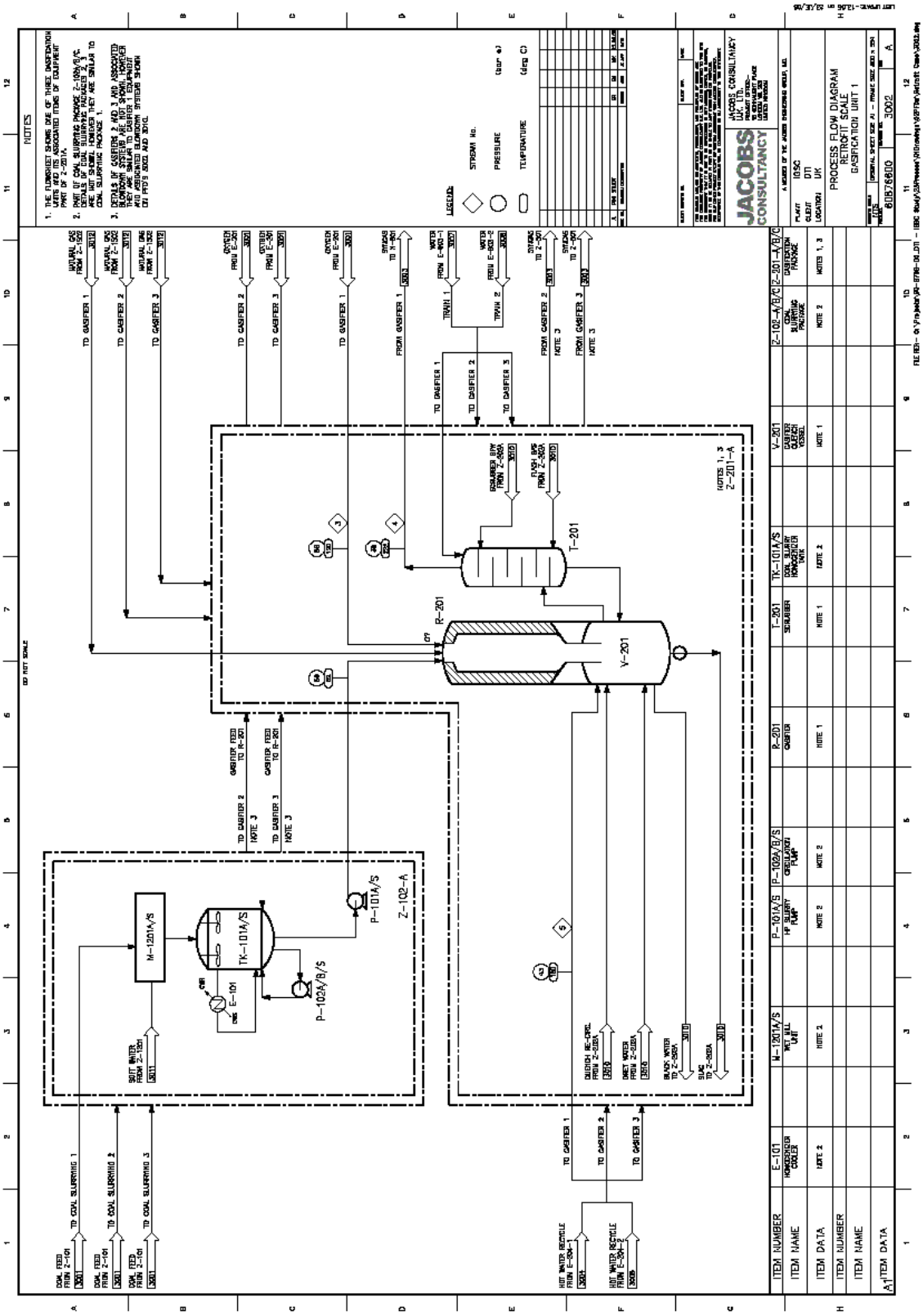

DO NOT SCALE
Z-202A/B/C/D
Z-201A/B/C/D
BLACK WATER FROM V-201
2002
FROM GASIFIER 1
NOTE 3
SLAG FROM V-201
2002
FROM GASIFIER 1
NOTE 3
QUENCH RE-CIRC. TO V-201
2002
TO GASIFIER 1
NOTE 3
GREY WATER TO V-201
2002
TO GASIFIER 1
NOTE 3
TO GASIFIER 1
NOTE 3
SCRUBBER BRW TO T-201
2002
FLASH GAS TO T-201
2002
GNM FROM Z-1001
2011
GASIFIER BLOWDOWN 1
GASIFIER BLOWDOWN 2
GASIFIER BLOWDOWN 3
GASIFIER BLOWDOWN 4
TRAIN 1
TRAIN 2
ATU FLASH GAS TO T-701A/B-1
ATU FLASH GAS TO T-701A/B-2
2007
2008
BLACK WATER TO Z-1301
2012
SLAG/ SOLID WASTE TO DISPOSAL
NOTES
1. EQUIPMENT PART OF GASIFICATION UNIT PACKAGE Z-201A/B/C/D.
2. THE FLOWSHEET SHOWS ONE OF FOUR GASIFICATION UNITS AND ITS ASSOCIATED QUENCH BLOWDOWN TREATMENT EQUIPMENT.
3. DETAILS OF GASIFIERS 2, 3 AND 4 AND ASSOCIATED BLOWDOWN SYSTEMS ARE NOT SHOWN, HOWEVER THEY ARE SIMILAR TO GASIFIER 1 EQUIPMENT AND ASSOCIATED BLOWDOWN SYSTEMS SHOWN ON PFD'S 3002 AND 2010.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
JACOBS CONSULTANCY
JACOBS CONSULTANCY U.K. LTD.
PROJECT OFFICE:-
18 GROSVENOR PLACE
LONDON SW1X 7HS
UNITED KINGDOM
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.
PLANT IGSC
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
UTILITY SCALE
QUENCH BLOWDOWN TREATMENT
(GASIFICATION UNIT 1)
SCALE NTS
ORIGINAL SHEET SIZE A1 – FRAME SIZE 800 x 594
6D876600
2010
A
ITEM NUMBER Z-202A/B/C/D
ITEM NAME BLOWDOWN SYSTEM
ITEM DATA NOTE 1
ITEM NUMBER
ITEM NAME
ITEM DATA
A1

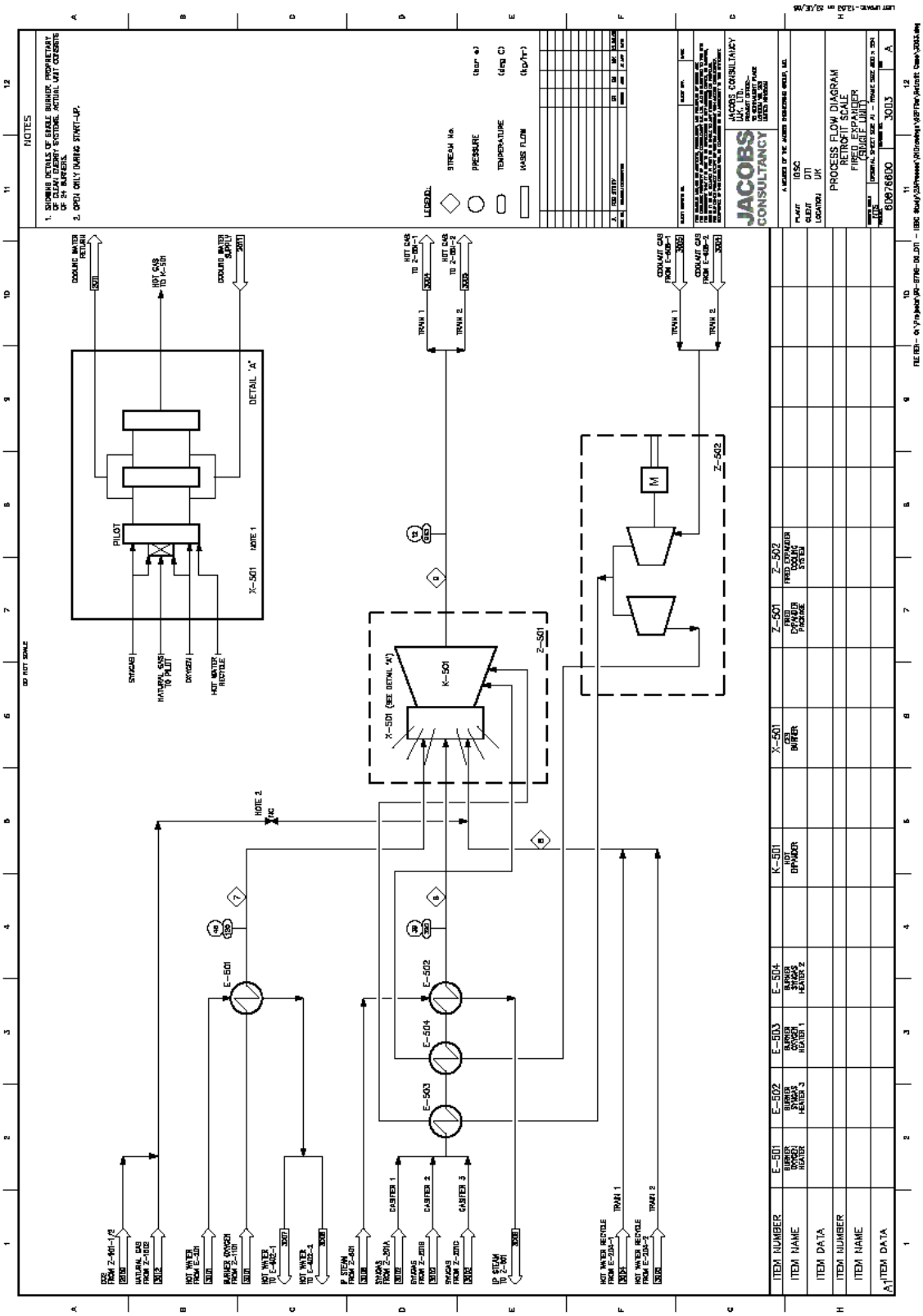

NOTES
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
JACOBS CONSULTANCY
JACOBS CONSULTANCY UK LTD.
PROJECT DETAILS:
PLANT 1GSC
SUBUNIT D71
LOCATION UK
PROCESS FLOW DIAGRAM
UTILITY SCALE
SEPARATOR/COOLING WATER SUPPLY
(DATA TRAINS)
DRAWING NUMBER 61967-6100
ISSUE NO. 2011
A
Z-1202
Z-1201
Z-1203
DEM TO USERS
DEM TO USERS
SOFT WATER TO USERS
RAW WATER
COOLING WATER SUPPLY TO USERS
EVAPORATION LOSS
CW MAKE-UP FROM Z-1201 2011
COOLING WATER RETURN FROM USERS
TO ATMOS.
V-601H-1
TRAIN 1
V-601B-1
P-601A-1
P-601B/S-1
V-601H-2
TRAIN 2
V-601B-2
P-601A-2
P-601B/S-2
LP STEAM FROM E-402A/B-1 2005
LP CONDENSATE FROM E-404A/B 2007
LP BFW TO E-402A/B-1 2007
LP STEAM FROM E-402A/B-2 2005
LP CONDENSATE FROM E-404A/B 2008
LP BFW TO E-402A/B-2 2008
ITEM NUMBER
ITEM NAME
ITEM DATA
P-601A/B/S
LP BFW PUMP
V-601B-1/2
DEAERATOR BOTTOM
V-601H-1/2
DEAERATOR HEAD
Z-1201
RAW WATER TREATMENT
Z-1202
BFW WATER TREATMENT
Z-1203
COOLING WATER SYSTEM
A1

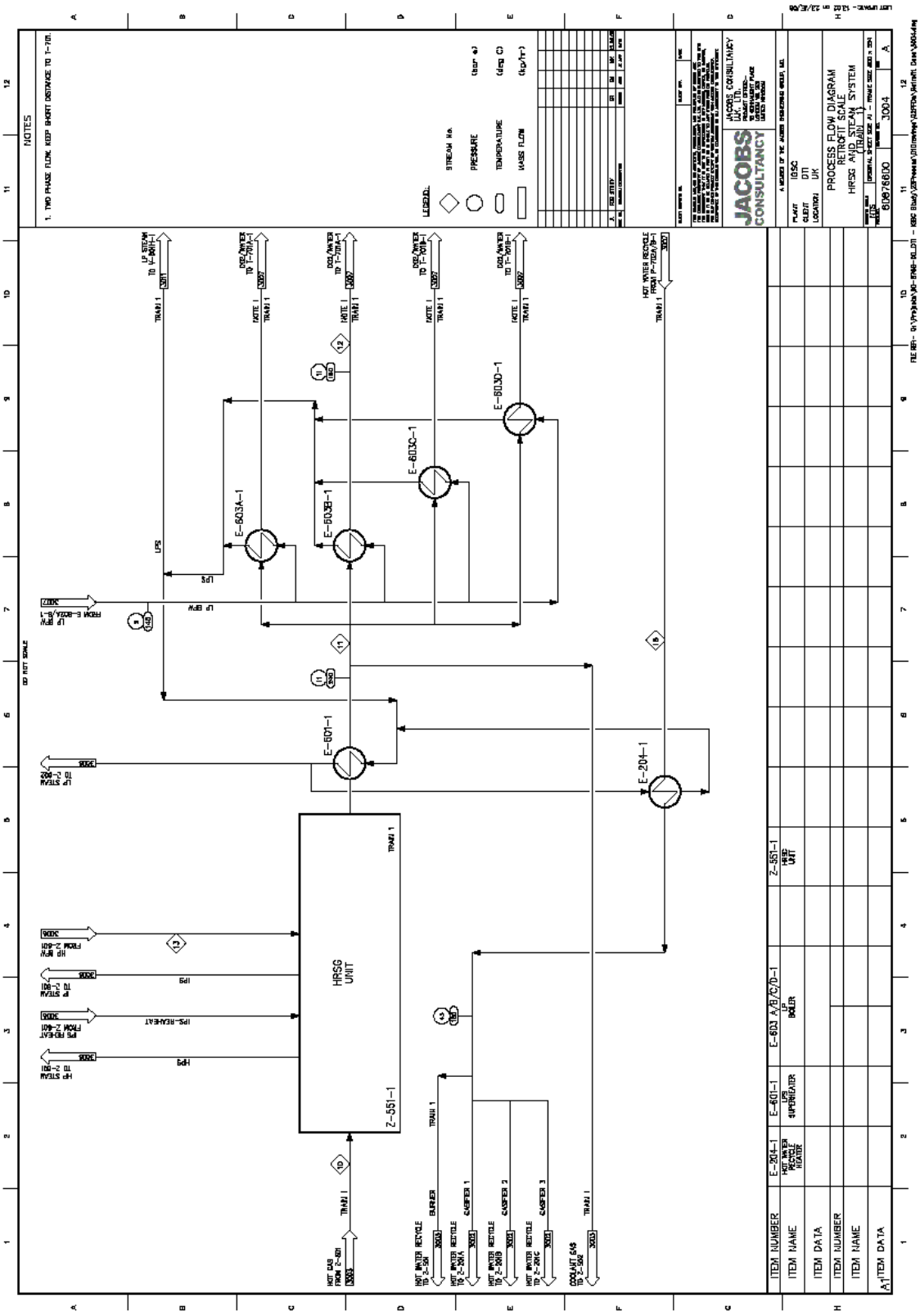

NOTES
1. OPEN ONLY DURING START-UP.
LEGEND
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
UTILITY SYSTEMS
(BOTH TRAINS)
2012
Z-1501
AIR COMPRESSOR
AIR COOLER
Z-1502
Z-1301
Z-1503
TO GASIFIER 1
TO GASIFIER 2
TO GASIFIER 3
TO GASIFIER 4
RECOVERED OIL TO DISPOSAL
TREATED EFFLUENT TO DISCHARGE
PROCESS CONDENSATE FROM Z-301-1/2
PURGE FROM E-604A/1
PURGE FROM E-604A/2
STORM WATER DISCHARGE
TREATED SEWAGE TO LANDFILL
AIR
NATURAL GAS SUPPLY
BLACK WATER FROM Z-301A-D
PLANT EFFLUENT (WATER + DISCHARGES) CONTAMINATED (BOUB)
LP BLOWDOWN FROM Z-401
PURGE FROM E-604B/2
PURGE FROM E-604A/2
DOMESTIC SEWAGE SITE
STORM WATER FROM ALL AREAS
ITEM NUMBER
ITEM NAME
ITEM DATA
A1

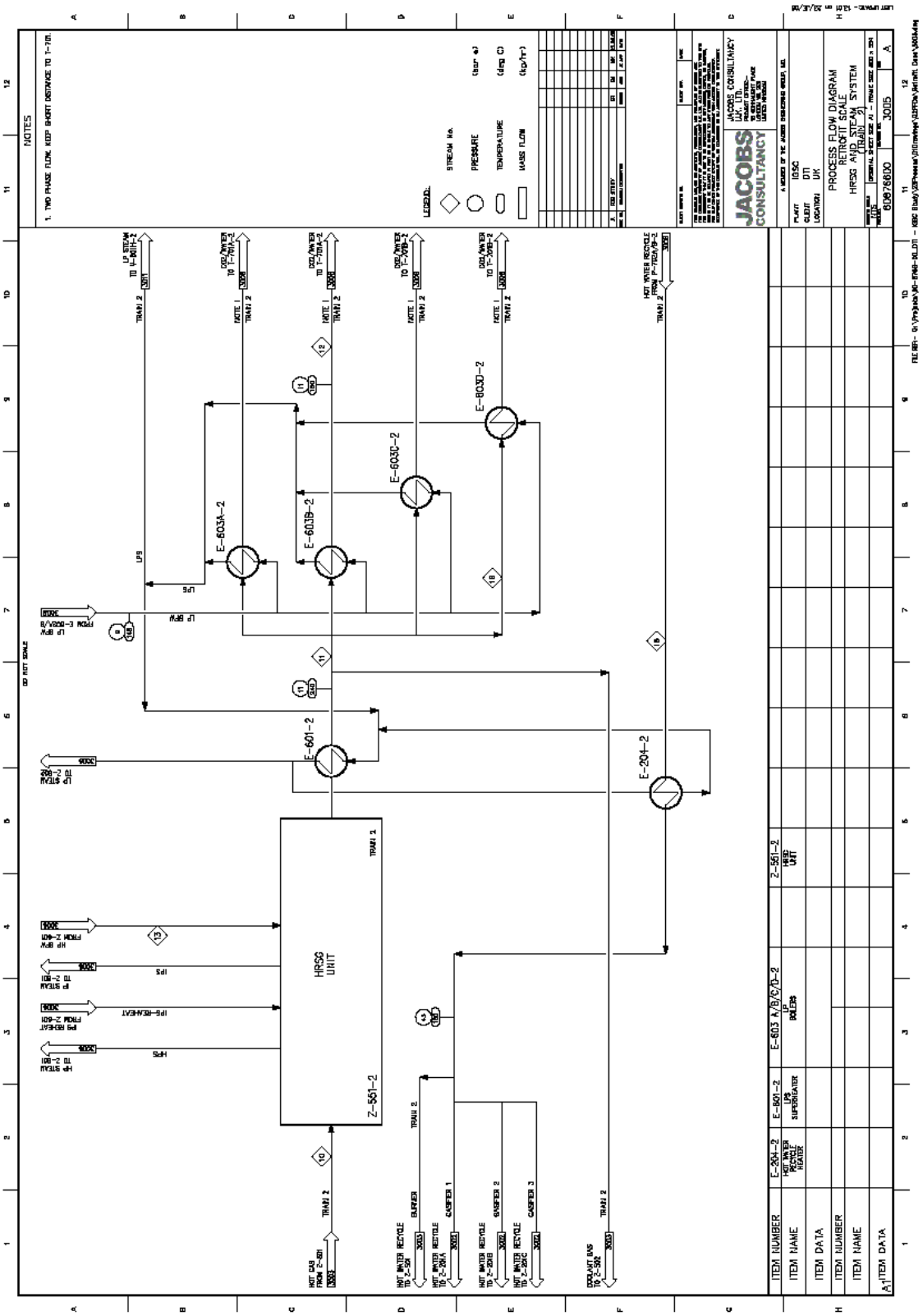
A2 Retrofit Case PFDs

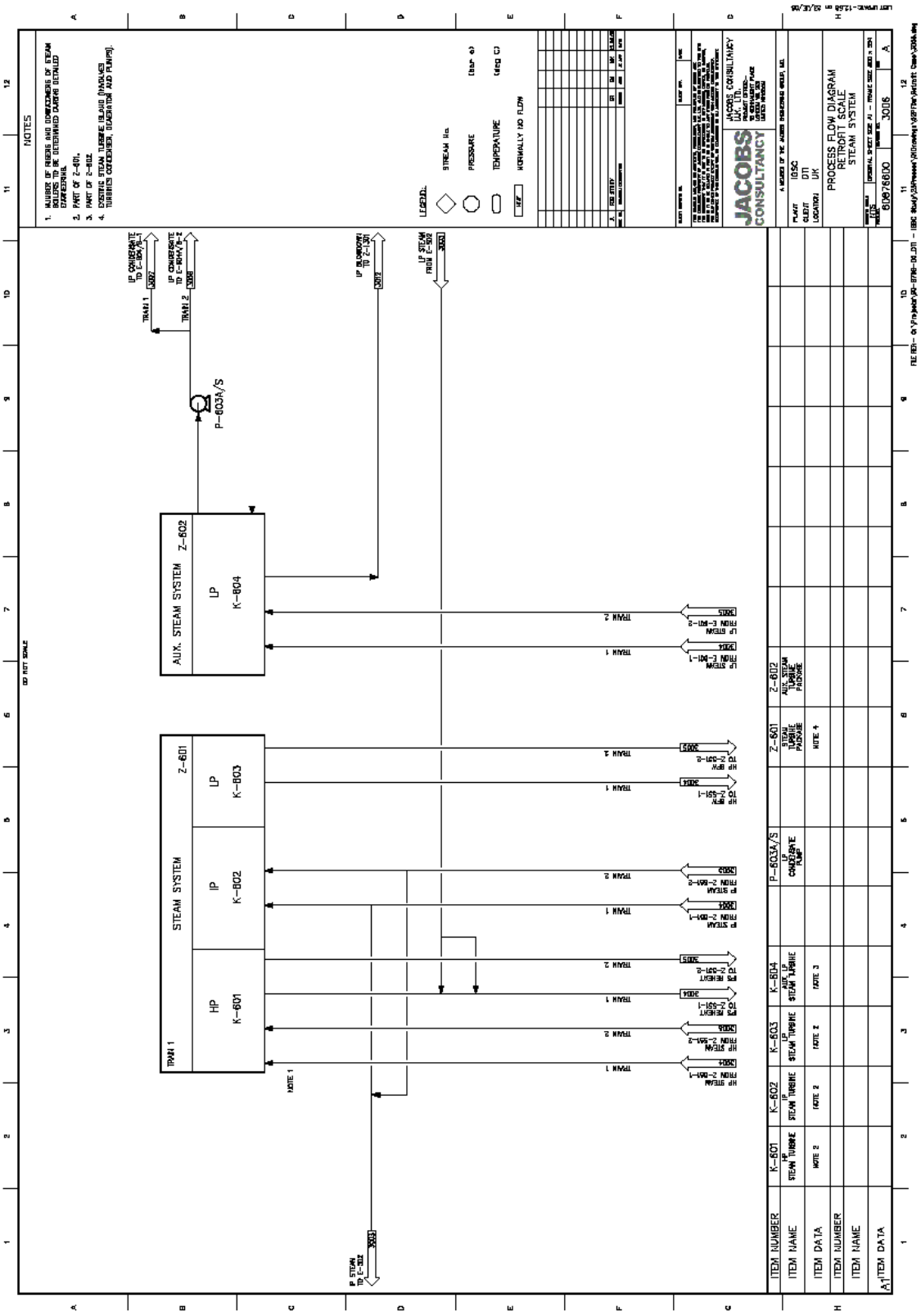


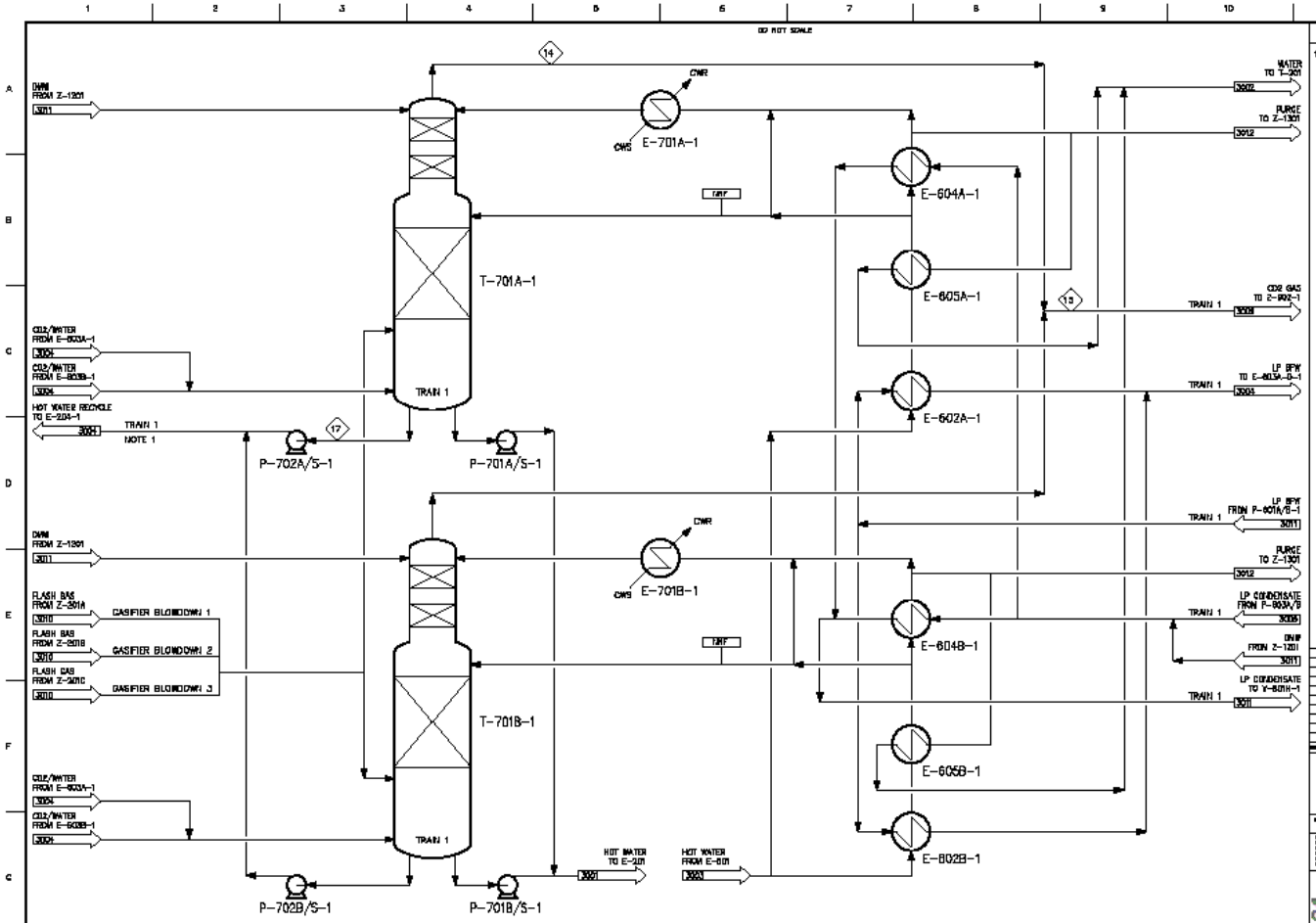

NOTES
1. THE FLOWSHEET SHOWS ONE OF THREE GASIFICATION UNITS AND ITS ASSOCIATED ITEMS OF EQUIPMENT PART OF Z-201A.
2. PARTS OF COAL SLURRYING PACKAGE Z-102A/B/C DETAILS OF COAL SLURRYING PACKAGES 2 & 3 ARE NOT SHOWN, HOWEVER THEY ARE SIMILAR TO COAL SLURRYING PACKAGE 1.
3. DETAILS OF GASIFIER 2 AND 3 AND ASSOCIATED TEMPERATURE, PRESSURE AND FLOW SENSORS ARE NOT SHOWN, HOWEVER THEY ARE SIMILAR TO GASIFIER 1 AND ASSOCIATED ELEMENTS SYSTEMS SHOWN ON PFD'S 3002 AND 3012.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
GASIFICATION UNIT 1
3002
NOT SCALE
Z-201
T-201
R-201
V-201
TK-1101A/S
M-1201A/S
E-101
P-101A/S
P-102A/B/S
Z-102-A
Z-102-A/B/C
ITEM NUMBER
ITEM NAME
ITEM DATA


NOTES
1. SHOWING DETAILS OF SINGLE BURNER. PROPRIETARY OF CLEAN ENERGY SYSTEMS. ACTUAL UNIT CONSISTS OF 24 BURNERS.
2. OPEN ONLY DURING START-UP.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
FIRED EVAPORATOR
(SINGLE UNIT)
DO NOT SCALE
DETAIL 'A'
X-501
NOTE 1
PILOT
K-501
Z-501
Z-502
E-501
E-502
E-503
E-504
TRAIN 1
TRAIN 2
NOTE 2
ITEM NUMBER
ITEM NAME
ITEM DATA


NOTES
1. TWO PHASE FLOW. KEEP SHORT DISTANCE TO T-701.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
HRSG AUD STEAM SYSTEM
(TRIAL)
PLANT IGSC
CLIENT DTI
LOCATION UK
DO NOT SCALE
HRSG UNIT
Z-551-1
E-601-1
E-603A-1
E-603B-1
E-603C-1
E-603D-1
E-204-1
LP STEAM TO V-801H-1
DEA/WATER TO T-701A-1
DEA/WATER TO T-701B-1
DEA/WATER TO T-701C-1
DEA/WATER TO T-701D-1
HOT WATER RECYCLE FROM P-702A/B-1
LP STEAM TO Z-602
HP STEAM TO Z-601
IP STEAM TO Z-601
IPS REHEAT FROM Z-601
HP STEAM FROM Z-601
LP GEN FROM E-603A/B-1
HOT GAS FROM Z-601
HOT WATER RECYCLE TO Z-501
HOT WATER RECYCLE TO Z-603A
HOT WATER RECYCLE TO Z-603B
HOT WATER RECYCLE TO Z-603C
COOLANT GAS TO Z-502
ITEM NUMBER
ITEM NAME
ITEM DATA
E-204-1 HOT WATER RECYCLE HEATER
E-601-1 LPS SUPERHEATER
E-603 A/B/C/D-1 LP BOILER
Z-551-1 HRSG UNIT
6109766D0
3004
A


NOTES
1. TWO PHASE FLOW, KEEP SHORT DISTANCE TO T-701.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
HRSG AND STEAM SYSTEM
(TRAIN 2)
PLANT 1050
CLIENT DTI
LOCATION UK
DOC NOT SCALE
HRSG UNIT
Z-551-2
E-601-2
E-603A-2
E-603B-2
E-603C-2
E-603D-2
E-204-2
E-801-2
E-603 A/B/C/D-2
ITEM NUMBER
ITEM NAME
ITEM DATA
A1


NOTES
1. NUMBER OF RISERS AND DOWNCOMERS OF STEAM BOILERS TO BE DETERMINED DURING DETAILED DESIGN PHASE.
2. PART OF Z-601.
3. PART OF Z-602.
4. EXISTING STEAM TURBINE (LEAD) (INCLUDES TURBINES CONDENSER, EVACUATION AND PUMPS).
LEGEND.
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
NORMALLY NO FLOW
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
STEAM SYSTEM
DO NOT SCALE
STEAM SYSTEM Z-601
TRAIN 1
HP K-601
IP K-602
LP K-603
AUX. STEAM SYSTEM Z-602
LP K-604
P-603A/S
ITEM NUMBER
ITEM NAME
ITEM DATA
K-601 HP STEAM TURBINE
K-602 IP STEAM TURBINE
K-603 LP STEAM TURBINE
K-604 AUX. LP STEAM TURBINE
P-603A/S LP CONDENSATE PUMP
Z-601 STEAM TURBINE PACKAGE
Z-602 AUX. STEAM TURBINE PACKAGE
NOTE 1
NOTE 2
NOTE 3
NOTE 4
A1 ITEM DATA



ITEM NUMBER	E-602A/B-1	E-604A/B-1	E-605A/B-1	E-701A/B-1		P-701A/B/S/S-1	P-702A/B/S/S-1		T-701A/B-1				
ITEM NAME	LP BFW HEATER	DMW HEATER	SCRUBBER WATER HEATER	DESATURATOR WATER COOLER		DESATURATOR CIRC. PUMP	MODERATOR WATER RECYCLE PUMP		DESATURATOR				
ITEM DATA													
ITEM NUMBER													
ITEM NAME													
ITEM DATA													

NOTES

1. THE HOT GAS FROM EXPANDER IS SPLIT EQUALLY INTO TWO TRAINS OF HRSG AND DESATURATOR. HOWEVER THE HOT WATER RECYCLE FROM DESATURATORS MAY CROSS BACK INTO HRSG'S IN BOTH TRAINS.

LEGEND:

◇	STREAM No.	
○	PRESSURE	(bar a)
⬭	TEMPERATURE	(deg C)
NRF	NORMALLY NO FLOW	
▭	MASS FLOW	(kg/hr)

A	FOR STUDY	BR	BM	MK	13.06.08
DWG NO.	DRAWING DESCRIPTION	DRAWN	CHKD	JC APP	DATE

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK. LTD.
PROJECT OFFICE:-
75 KEYMARKET PLACE
LONDON NW 1QN
UNITED KINGDOM

A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.

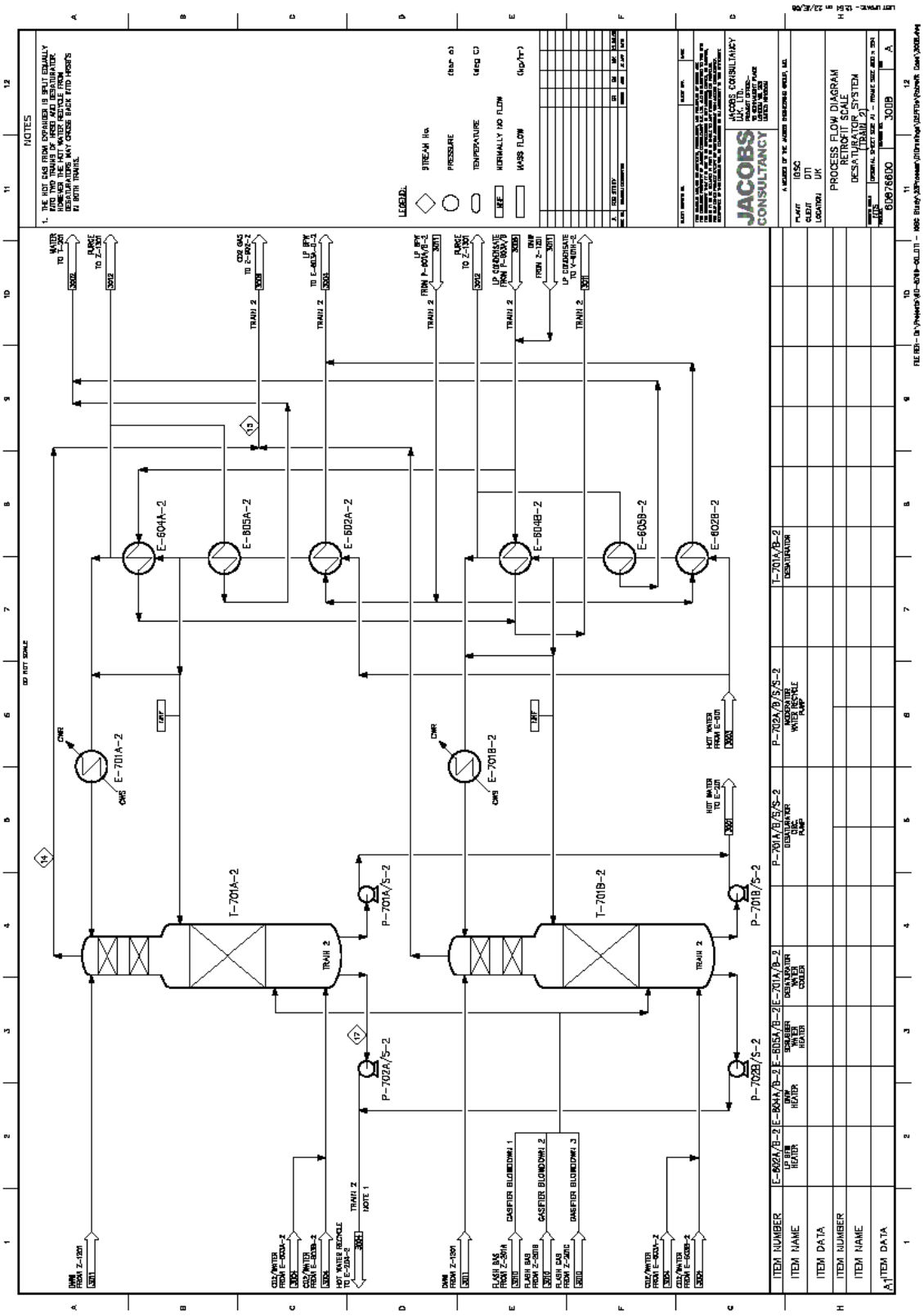
PLANT: IGSC
CLIENT: DTI
LOCATION: UK

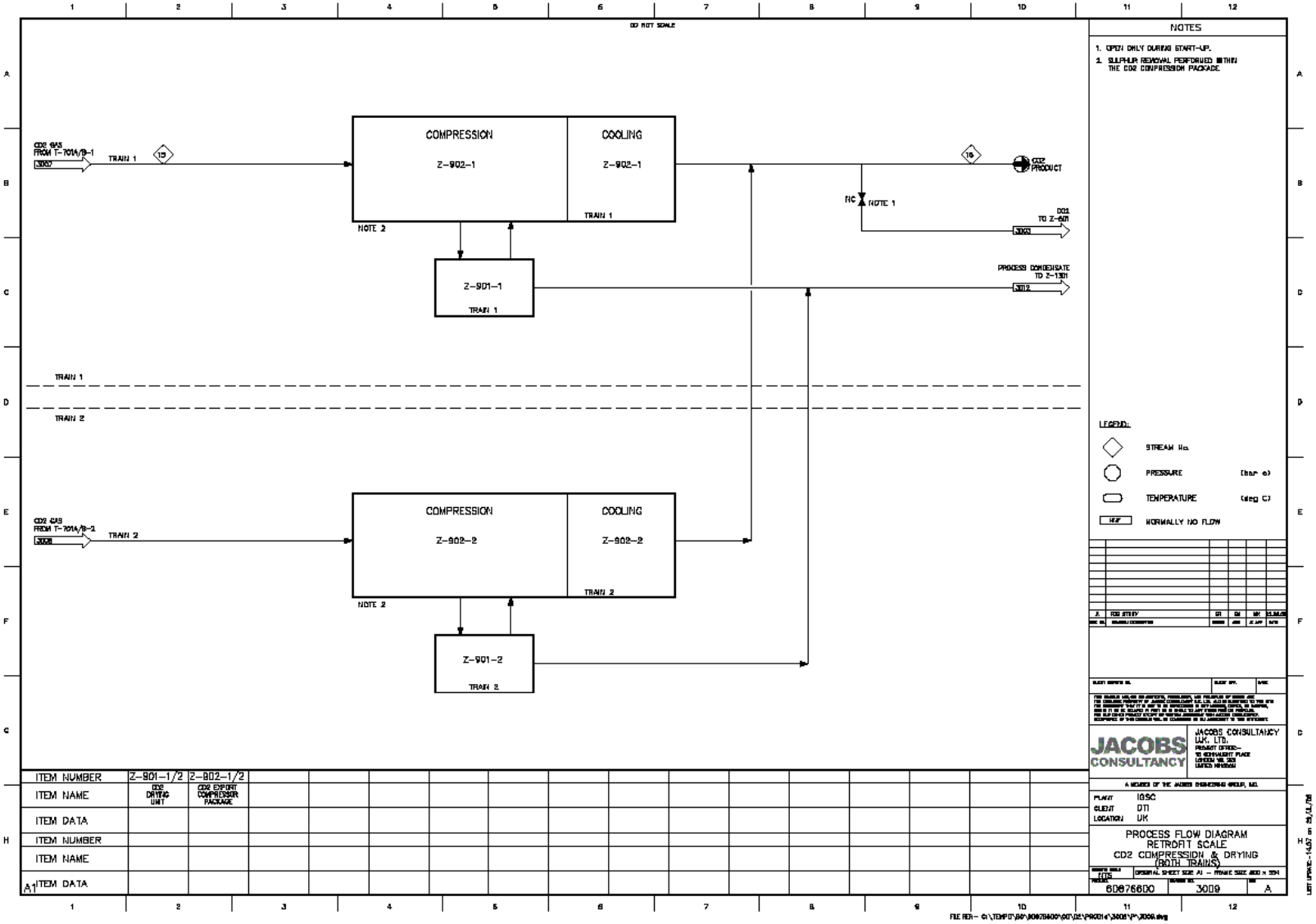
PROCESS FLOW DIAGRAM
RETROFIT SCALE
DESATURATOR SYSTEM
(TRAIN 1)

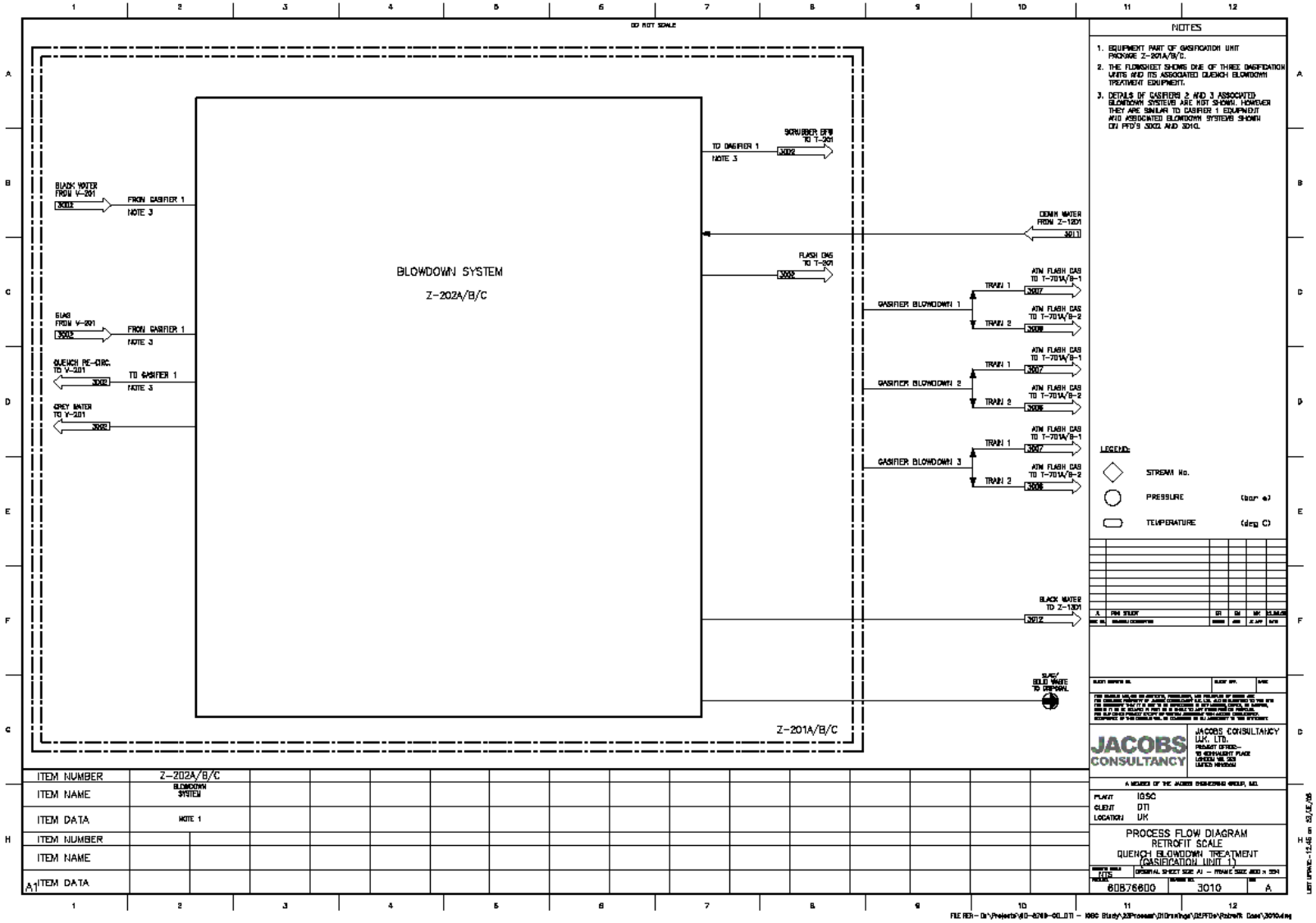
DRAWN SCALE: FOR
ORIGINAL SHEET SIZE A1 — FRAME SIZE 840 x 594
PROJECT: 6087660D
DRAWING NO.: 3007
REV: A

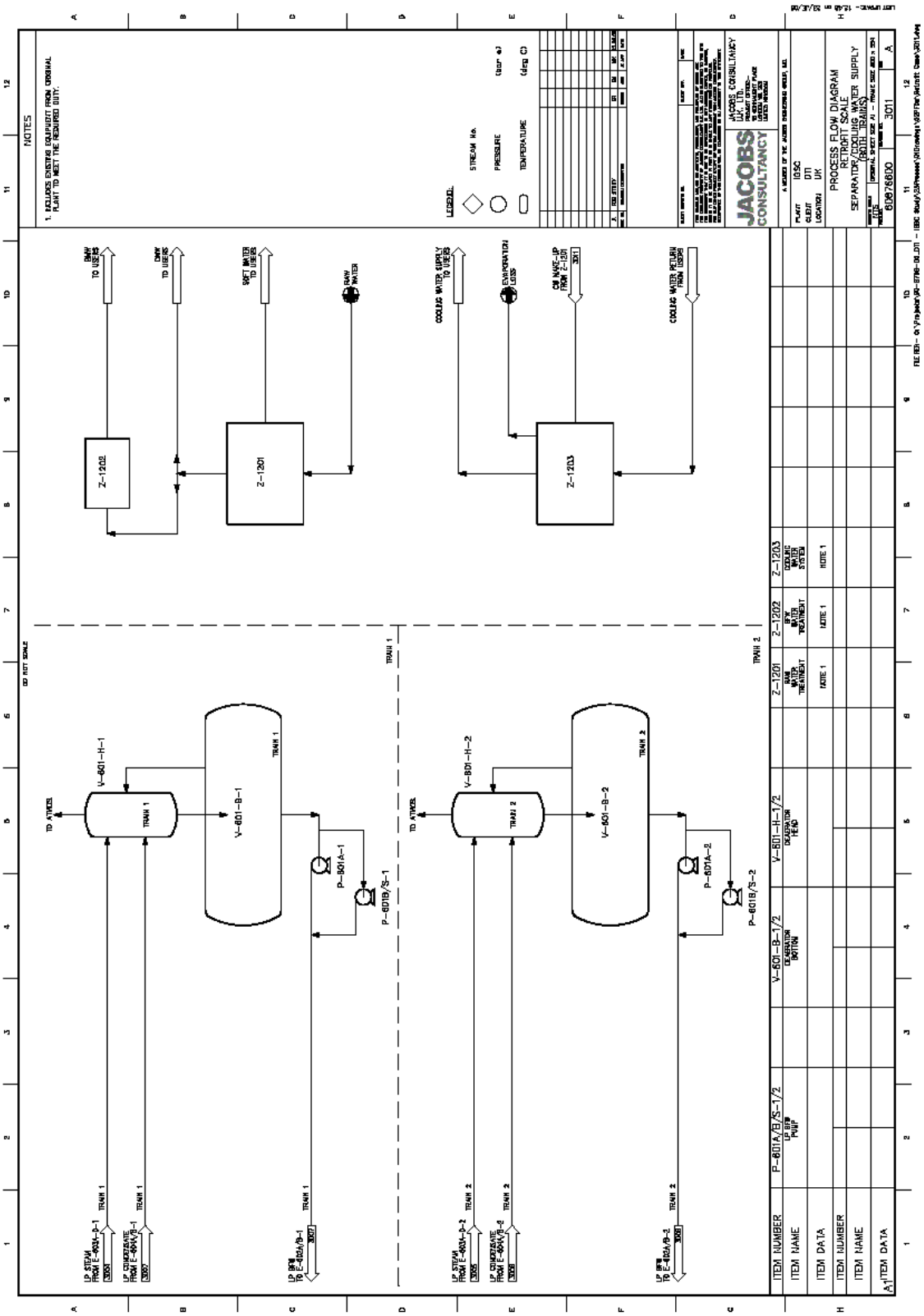
LAST UPDATED - 13.07 on 13/JUN/08

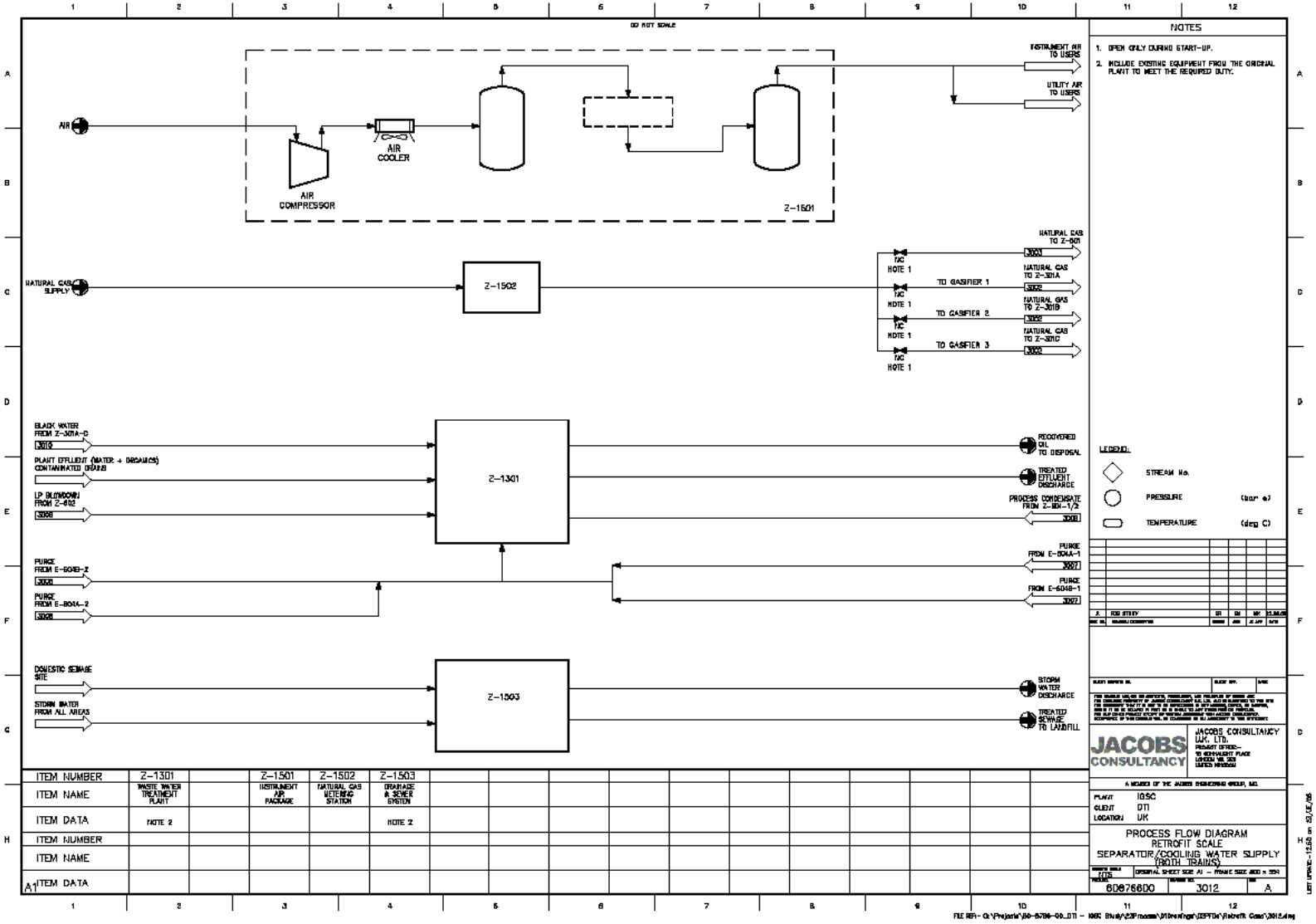
FILE REF - D:\Projects\60-6087-00_DTI - IGSC Study\30Process\210Drawings\02FFDs\Retrofit Case\3007.dwg


NOTES
1. THE HOT GAS FROM EXPANDER IS SPLIT EQUALLY INTO TWO TRAIN DESUPERHEATER TO GENERATE HOMOGENEOUS THE HOT WATER RECYCLE FROM DESATURATORS MAY CROSS BACK INTO HOSPITS BY BOTH TRAINS.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
NORMALLY NO FLOW
MASS FLOW (kg/hr)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
DESATURATION SYSTEM
E-604A-2
E-605A-2
E-602A-2
E-604B-2
E-605B-2
E-602B-2
E-701A-2
E-701B-2
T-701A-2
T-701B-2
P-701A/S-2
P-701B/S-2
P-702A/S-2
P-702B/S-2
TRAIN 2
CWR
CWS
DWM FROM Z-1301
FLASH GAS FROM Z-301A
FLASH GAS FROM Z-301B
FLASH GAS FROM Z-301C
GASIFIER BLOWDOWN 1
GASIFIER BLOWDOWN 2
GASIFIER BLOWDOWN 3
HOT WATER RECYCLE TO E-304-2
HOT WATER FROM E-601
HOT WATER TO E-601
ITEM NUMBER
ITEM NAME
ITEM DATA
ITEM NUMBER
ITEM NAME
ITEM DATA


DO NOT SCALE
CO2 GAS FROM T-701A/B-1
3007
TRAIN 1
13
COMPRESSION
Z-902-1
COOLING
Z-902-1
TRAIN 1
NOTE 2
Z-901-1
TRAIN 1
16
CO2 PRODUCT
FIC
NOTE 1
CO1 TO Z-601
3001
PROCESS CONDENSATE TO Z-1301
3012
TRAIN 1
TRAIN 2
CO2 GAS FROM T-701A/B-2
3008
TRAIN 2
COMPRESSION
Z-902-2
COOLING
Z-902-2
TRAIN 2
NOTE 2
Z-901-2
TRAIN 2
NOTES
1. OPEN ONLY DURING START-UP.
2. SULPHUR REMOVAL PERFORMED WITHIN THE CO2 COMPRESSION PACKAGE.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
NORMALLY NO FLOW
A. FOR STUDY
JACOBS CONSULTANCY
JACOBS CONSULTANCY (U.K. LTD.
PROJECT OFFICE:-
10 GOSWALLWELL PLACE
LONDON NW1 5DX
UNITED KINGDOM
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.
PLANT IGSC
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
RETROFIT SCALE
CO2 COMPRESSION & DRYING
(BOTH TRAINS)
FLOW
ORIGINAL SHEET SIZE A1 – FRAME SIZE 800 x 594
6D876600
3009
A
ITEM NUMBER
Z-901-1/2
Z-902-1/2
ITEM NAME
CO2 DRYING UNIT
CO2 EXPORT COMPRESSOR PACKAGE
ITEM DATA
ITEM NUMBER
ITEM NAME
ITEM DATA
A1


DO NOT SCALE
BLOWDOWN SYSTEM
Z-202A/B/C
Z-201A/B/C
BLACK WATER FROM V-201
3002
FROM GASIFIER 1
NOTE 3
SLAG FROM V-201
3003
FROM GASIFIER 1
NOTE 3
QUENCH RE-CIRC. TO V-201
3002
TO GASIFIER 1
NOTE 3
GREY WATER TO V-201
3002
TO GASIFIER 1
NOTE 3
SCRUBBER EFFN TO T-201
3002
FLASH GAS TO T-201
3002
DEMIN WATER FROM Z-1201
3011
GASIFIER BLOWDOWN 1
GASIFIER BLOWDOWN 2
GASIFIER BLOWDOWN 3
TRAIN 1
TRAIN 2
ATM FLASH GAS TO T-701A/B-1
3007
ATM FLASH GAS TO T-701A/B-2
3008
BLACK WATER TO Z-1201
3012
SLAG/ SOLID WASTE TO DISPOSAL
NOTES
1. EQUIPMENT PART OF GASIFICATION UNIT PACKAGE Z-201A/B/C.
2. THE FLOWSHEET SHOWS ONE OF THREE GASIFICATION UNITS AND ITS ASSOCIATED QUENCH BLOWDOWN TREATMENT EQUIPMENT.
3. DETAILS OF GASIFIERS 2 AND 3 ASSOCIATED BLOWDOWN SYSTEMS ARE NOT SHOWN. HOWEVER THEY ARE SIMILAR TO GASIFIER 1 EQUIPMENT AND ASSOCIATED BLOWDOWN SYSTEMS SHOWN ON PFD'S 3002 AND 3010.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
A FIRM ISSUE
JACOBS CONSULTANCY
JACOBS CONSULTANCY U.K. LTD.
PROJECT OFFICE:-
10 GRESHAM PLACE
LONDON WC2V 7AD
UNITED KINGDOM
A MEMBER OF THE JACOBS ENGINEERING GROUP, INC.
PLANT 10SC
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
RETROFIT SCALE
QUENCH BLOWDOWN TREATMENT
(GASIFICATION UNIT 1)
DTI
ORIGINAL SHEET SIZE A1 — FRAME SIZE 800 x 594
80876600
3010
A
ITEM NUMBER
Z-202A/B/C
ITEM NAME
BLOWDOWN SYSTEM
ITEM DATA
NOTE 1
ITEM NUMBER
ITEM NAME
ITEM DATA
A1
LAST UPDATE - 12:46 on 03/8/05


NOTES
1. INCLUDES EXISTING EQUIPMENT FROM ORIGINAL PLANT TO MEET THE REQUIRED DUTY.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
JACOBS CONSULTANCY
PROCESS FLOW DIAGRAM
RETROFIT SCALE
SEPARATOR/COOLING WATER SUPPLY
(BOTH TRAINS)
Z-1202
Z-1201
Z-1203
RAW WATER TO USERS
SOFT WATER TO USERS
RAW WATER
COOLING WATER SUPPLY TO USERS
EVAPORATION LOSS
CW MAKE-UP FROM Z-1201
COOLING WATER RETURN FROM USERS
TO ATMOS.
V-601-H-1
V-601-B-1
V-601-H-2
V-601-B-2
TRAIN 1
TRAIN 2
P-601A-1
P-601B/S-1
P-601A-2
P-601B/S-2
LP STEAM FROM E-402A-D-1
LP CONDENSATE FROM E-404V/S-1
LP STEAM FROM E-402A-D-2
LP CONDENSATE FROM E-404V/S-2
LP STEAM TO E-402A/B-1
LP STEAM TO E-402A/B-2
ITEM NUMBER
ITEM NAME
ITEM DATA
P-601A/B/S-1/2
LP STEAM PUMP
V-601-B-1/2
DEAERATION BOTTOM
V-601-H-1/2
DEAERATION HEAD
Z-1201
RAW WATER TREATMENT
Z-1202
SOFT WATER TREATMENT
Z-1203
COOLING WATER SYSTEM
NOTE 1
PLANT: 1050
CLIENT: DTI
LOCATION: UK
PROJECT NUMBER: 61067660
DRAWING NO.: 3011
A


DO NOT SCALE
AIR
AIR COMPRESSOR
AIR COOLER
Z-1501
INSTRUMENT AIR TO USERS
UTILITY AIR TO USERS
NATURAL GAS SUPPLY
Z-1502
NATURAL GAS TO Z-601
NATURAL GAS TO Z-301A
NATURAL GAS TO Z-301B
NATURAL GAS TO Z-301C
TO GASIFIER 1
TO GASIFIER 2
TO GASIFIER 3
NOTE 1
BLACK WATER FROM Z-301A-C
PLANT EFFLUENT (WATER + DRAINS) CONTAMINATED DRAINS
LP BLOWDOWN FROM Z-602
Z-1301
RECOVERED OIL TO DISPOSAL
TREATED EFFLUENT DISCHARGE
PROCESS CONDENSATE FROM Z-101-1/2
PURGE FROM E-503B-2
PURGE FROM E-503A-2
PURGE FROM E-503A-1
PURGE FROM E-503B-1
DOMESTIC SEWAGE SITE
STORM WATER FROM ALL AREAS
Z-1503
STORM WATER DISCHARGE
TREATED SEWAGE TO LANDFILL
NOTES
1. OPEN ONLY DURING START-UP.
2. INCLUDE EXISTING EQUIPMENT FROM THE ORIGINAL PLANT TO MEET THE REQUIRED DUTY.
LEGEND:
STREAM No.
PRESSURE (bar a)
TEMPERATURE (deg C)
ITEM NUMBER Z-1301 Z-1501 Z-1502 Z-1503
ITEM NAME WASTE WATER TREATMENT PLANT INSTRUMENT AIR PACKAGE NATURAL GAS METERING STATION DRAINAGE & SEWER SYSTEM
ITEM DATA NOTE 2 NOTE 2
JACOBS CONSULTANCY
JACOBS CONSULTANCY (UK) LTD.
PLANT 1050
CLIENT DTI
LOCATION UK
PROCESS FLOW DIAGRAM
RETROFIT SCALE
SEPARATOR/COOLING WATER SUPPLY (BOTH TRAINS)
6D076600
3012
A

APPENDIX B – EQUIPMENT LIST UTILITY CASE

JDD94A/1 Printed 14:20 06-Oct-08 Filename: 8766-00_DTI - IGSC Study\23Process\03Schedules (Lists)\01Master Schedules\Utility Case\[Equipment_LIST_ALL_AREAS Rev

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

DEPARTMENT/GROUP		Copies
PROJECT MANAGER	M. KARMARKAR	1+0
PROJECT DPE	D. FRANCIS	0
PROCESS CONSULTANT	J. GRIFFITHS	1
PROCESS	E. MARGONO	1
PROCESS	A. TVELENEV	0
PROCESS	T. NANDI	0
PROCESS		
SAFETY	C. TOPHAM	1
VESSELS		
ELECTRICAL		
INSTRUMENTS		
MECHANICAL		
PIPING		
PROCUREMENT		
Q.A.		
PLANNING	K .FOSTER	
COMMISSIONING		
ESTIMATING	A.R.NORZIHAN	1
OTHER PARTIES	MAN TURBO SIEMENS	
	GE CES	
CLIENT	DTI	

PLANT: IGSC STUDY

CLIENT: DTI

LOCATION: CONFIDENTIAL

JOB NO.: 60.8766.00

SECTION :

OPTION:

NOTES

Contents **Page**

Rev.	Made by	Date	Checked by	Date	Approved by	Date	Description
A	SV	08/02/08	MK	13/02/08	MK	14/02/08	PRELIMINARY - UTILITY CASE
B	AT	11/09/08	MK	19-09-08	MK	19-09-08	FINAL - UTILITY CASE

Sheet 1 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 100- Coal Handling			
	C-1201	1	0	UNLOADING STATION CONVEYOR	NO	NO	PART OF Z-101.
	C-1202	1	0	COAL STORAGE CONVEYOR	NO	NO	PART OF Z-101.
	C-1203	1	0	COAL RECLAIMER	NO	NO	PART OF Z-101.
	C-1204	1	0	REVERSIBLE BELT CONVEYOR	NO	YES	PART OF Z-101.
	C-1205	1	0	BUCKET ELEVATOR	NO	YES	PART OF Z-101.
	C-1206	1	0	PREPARED COAL CONVEYOR	NO	NO	PART OF Z-101.
	C-1207	1	0	MILL FEED CONVEYOR	NO	NO	PART OF Z-101.
	CR-1201A/S	1	1	CRUSHER	NO	YES	PART OF Z-101.
	E-101 A/B/C/D	4	0	HOMOGENIZER COOLER	YES	NO	PART OF Z-102 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	M-1201 A/S	4	4	WET MILL UNIT	NO	NO	PART OF Z-102 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	P-101A/S	4	4	HP SLURRY PUMP	YES	YES	PART OF Z-102 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	P-102 A/B/C/S	12	4	CIRCULATION PUMP	YES	YES	PART OF Z-102 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 2 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 100- Coal Handling (CONT.)			
	SC-1201 A/S	1	1	SCREEN	NO	NO	PART OF Z-101.
	TK-101 A/S	4	4	COAL SLURRY HOMOGENIZER TANK	NO	NO	PART OF Z-102 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	V-1201	1	0	COAL SLOT STORAGE	NO	NO	PART OF Z-101.
	V-1202 A/B/C/ D/E/F	6	0	PREPARED COAL STORAGE	NO	NO	PART OF Z-101.
	X-1201	1	0	DEDUSTING SYSTEM	NO	NO	PART OF Z-101.
	X-1202	1	0	METAL DETECTOR	NO	NO	PART OF Z-101.
	X-1203	1	0	SUSPENDED MAGNET	NO	NO	PART OF Z-101.
	Z-101	1	0	COAL STORAGE & PREPARATION PACKAGE	NO	YES	
	Z-102 A/B/C/D	4	0	COAL SLURRYING PACKAGE	YES	YES	ASSOCIATED WITH 4 GASIFIERS.

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 3 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 200 - Gasification			
	E-201	1	0	GASIFIER OXYGEN HEATER	YES	NO	
	E-204 - 1	1	0	HOT WATER RECYCLE HEATER - TRAIN 1	YES	NO	
	E-204 - 2	1	0	HOT WATER RECYCLE HEATER - TRAIN 2	YES	NO	
	R-201	4	0	GASIFIER	YES	NO	PART OF Z-201 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	T-201	4	0	SCRUBBER	YES	NO	PART OF Z-201 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	V-201	4	0	GASIFIER QUENCH VESSEL	YES	YES	PART OF Z-201 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.
	Z-201 A/B/C/D	4	0	GASIFICATION PACKAGE	YES	YES	INCLUDES 4 GASIFIERS.
	Z-202 A/B/C/D	4	0	BLOWDOWN SYSTEM	YES	YES	PART OF Z-201 A/B/C/D. ASSOCIATED WITH 4 GASIFIERS.

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 4 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 500 - Fired Expander			
	E-501	1	0	BURNER OXYGEN HEATER	YES	NO	
	E-502	1	0	BURNER SYNGAS HEATER	YES	NO	
	K-501	1	0	FIRED EXPANDER	YES	NO	PART OF Z-501.
	X-501	24	0	CES BURNER	YES	NO	PART OF Z-501.
	Z-501	1	0	FIRED EXPANDER PACKAGE	YES	NO	
	Z-502	1	0	FIRED EXPANDER COOLING SYSTEM	YES	YES	

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 5 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 550 - HRSG UNIT			
	Z-551- 1	1	0	HRSG (HEAT RECOVERY STEAM GENERATION UNIT) - TRAIN 1	YES	NO	ONE UNIT OPERATING PER TRAIN .
	Z-551- 2	1	0	HRSG (HEAT RECOVERY STEAM GENERATION UNIT) - TRAIN 2	YES	NO	ONE UNIT OPERATING PER TRAIN

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 6 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 600 - Steam System & Deaerator			
	E-601 - 1	1	0	HP BFW HEATER 1 - TRAIN 1	YES	NO	
	E-601 - 2	1	0	HP BFW HEATER 1 - TRAIN 2	YES	NO	
	E-602 A/B - 1	2	0	LP BFW HEATER 2 - TRAIN 1	YES	NO	
	E-602 A/B - 2	2	0	LP BFW HEATER 2 - TRAIN 2	YES	NO	
	E-603 A/B/C/D - 1	4	0	LP BOILER - TRAIN 1	YES	NO	
	E-603 A/B/C/D - 2	4	0	LP BOILER - TRAIN 2	YES	NO	
	E-604 A/B - 1	2	0	DEMINERALISED WATER HEATER - TRAIN 1	YES	NO	
	E-604 A/B - 2	2	0	DEMINERALISED WATER HEATER - TRAIN 2	YES	NO	
	K-601	1	0	HP STEAM TURBINE	YES	NO	PART OF Z-601.
	K-602	1	0	IP STEAM TURBINE	YES	NO	PART OF Z-601.
	K-603	1	0	LP STEAM TURBINE	YES	NO	PART OF Z-601.
	P-601 A/B/S-1	2	1	LP BFW PUMP - TRAIN 1	NO	YES	
	P-601 A/B/S-2	2	1	LP BFW PUMP - TRAIN 2	NO	YES	
	P-602 A/S/B/S-1	2	2	HP BFW PUMP - TRAIN 1	NO	YES	
	P-602 A/S/B/S-2	2	2	HP BFW PUMP - TRAIN 2	NO	YES	
	P-603 A/S	1	1	LP CONDENSATE PUMP	NO	YES	

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 7 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 600 - Steam System & Deaerator			
	V-601 - 1	1	0	DEAERATOR - TRAIN 1	YES	NO	INCL. HEAD (V-601-H) & B'TT'M (V-601-B).
	V-601 - 2	1	0	DEAERATOR - TRAIN 2	YES	NO	INCL. HEAD (V-601-H) & B'TT'M (V-601-B).
	Z-601	1	0	STEAM TURBINE PACKAGE	YES	YES	ONE UNIT OPERATING PER TRAIN FOR TWO TRAINS .

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 8 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 700 - DESATURATOR SYSTEM			
	E-701 A/B - 1	2	0	DESATURATOR WATER COOLER - TRAIN 1	YES	NO	
	E-701 A/B - 2	2	0	DESATURATOR WATER COOLER - TRAIN 2	YES	NO	
	P-701 A/S/B/S - 1	2	2	DESATURATOR CIRCULATION PUMP - TRAIN 1	YES	YES	
	P-701 A/S/B/S - 2	2	2	DESATURATOR CIRCULATION PUMP - TRAIN 2	YES	YES	
	P-702 A/S/B/S - 1	2	2	MODERATOR WATER RECYCLE PUMP - TRAIN 1	YES	YES	
	P-702 A/S/B/S - 2	2	2	MODERATOR WATER RECYCLE PUMP - TRAIN 2	YES	YES	
	T-701 A/B - 1	2	0	DESATURATOR - TRAIN 1	YES	NO	
	T-701 A/B - 2	2	0	DESATURATOR - TRAIN 2	YES	NO	

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 9 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 900 - CO2 COMPRESSION AND DRYING			
	Z-901 - 1	1	0	CO2 DRYING UNIT - TRAIN 1	YES	YES	
	Z-902 - 1	1	0	CO2 EXPORT PACKAGE - TRAIN 1	YES	YES	
	Z-901 - 2	1	0	CO2 DRYING UNIT - TRAIN 2	YES	YES	
	Z-902 - 2	1	0	CO2 EXPORT PACKAGE - TRAIN 2	YES	YES	

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 10 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 1100- ASU & OXYGEN SUPPLY			
	Z-1101	1	0	AIR SEPARATION UNIT	YES	YES	
				AREA 1200 - WATER TREATMENT			
	Z-1201	1	0	RAW WATER TREATMENT	NO	YES	
	Z-1202	1	0	BFW TREATMENT	NO	YES	
	Z-1203	1	0	COOLING WATER SYSTEM	NO	YES	
				AREA 1300 - WASTE WATER TREATMENT			
	Z-1301	1	0	WASTE WATER TREATMENT	NO	YES	

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 11 of 12

JACOBS CONSULTANCY

JACOBS CONSULTANCY UK LTD

EQUIPMENT LIST

Document No. 60876600-01-00/PRO.03a/0001/B

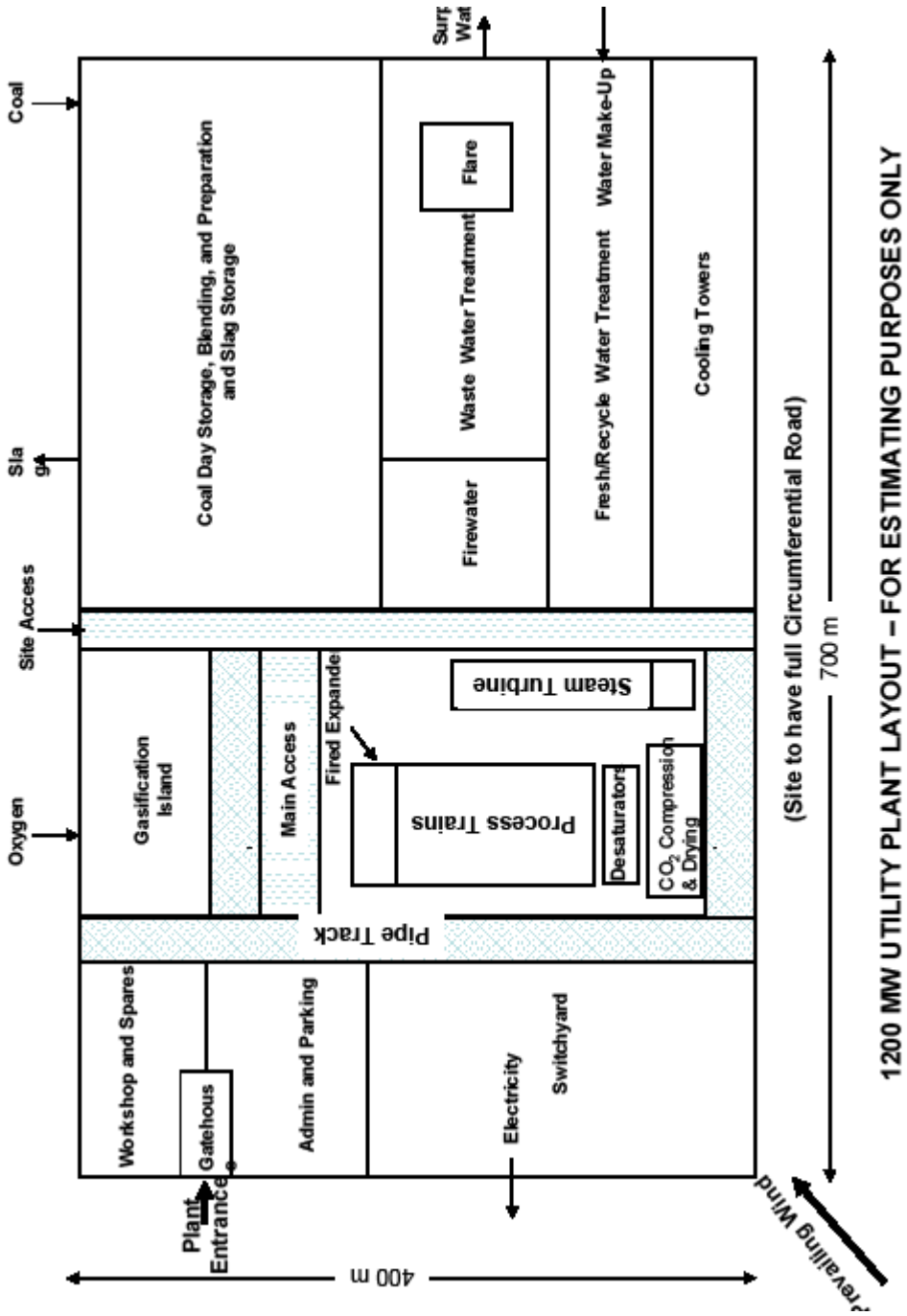
PLANT: IGSC STUDY
CLIENT: DTI
JOB NO.: 60.8766.00
LOCATION: CONFIDENTIAL

Rev.	Item Number	No. Installed W'king	No. Installed St'by	Description	Insulation Required	Electricity Required	Remarks
				AREA 1400- ELECTRICAL			
	Z-1401			ELECTRICAL SWITCHYARD	NO	YES	
				132kV/11kV TRANSFORMERS	NO	YES	PART OF Z-1401
				11kV/3kV TRANSFORMERS	NO	YES	PART OF Z-1401
				3kV/480V TRANSFORMERS	NO	YES	PART OF Z-1401
				AREA 1500 - MISC. UTILITIES			
	Z-1501	1	0	INSTRUMENT AIR PACKAGE	NO	YES	
	Z-1502	1	0	NG METERING	NO	YES	
	Z-1503	1	0	DRAINAGE & SEWER SYSTEM	NO	YES	
				AREA 1600 - MISC. UTILITIES			
				CONTROL ROOM			
				SWITCH ROOM			
				TURBINE HALL			
				ADMIN. BUILDING			
				WORKSHOP			
				MISC. BUILDINGS			VARIOUS

Rev	Made by	Date	Made by	Date	Approved by	Date	Description
							PRELIMINARY - UTILITY CASE
							FINAL - UTILITY CASE

Sheet 12 of 12

APPENDIX C – UTILITY CASE SCHEMATIC PLANT LAYOUT



APPENDIX D – ESTIMATE DETAILS

Appendix D1: Details of Elements that form Plant Installed Costs

a) Direct Field Material Costs

Direct field material costs are the costs of the permanent physical plant facilities and include the following elements:

- Excavation and Civil--Includes piling, roads, asphalt paving, and clean structural fill.
- Concrete and Fireproofing--Includes foundations, concrete structures, retaining walls, floor slabs, concrete area paving and concrete fireproofing.
- Structural Steel--Includes steel structures, pipe racks, handrails, ladders, stairs, platforms and miscellaneous supports.
- Buildings— Includes control, electrical substation, office, compressor, laboratory, warehouse, canteen, workshop and gatehouse buildings including framing, walls, exterior cladding and roofing, HVAC, electrical lighting and power, interior fixtures and finishes.
- Equipment-- Includes tanks, vessels, combustion turbines, steam turbines, compressors, heat exchangers, heat recovery steam generators (HRSG's), pumps, material processing equipment, material handling equipment, and miscellaneous equipment (e.g. filters, strainers, etc.)
- Piping-- Includes aboveground and underground pipe, fittings, valves, flanges, gaskets, shoes and guides, specialty items, and non-destructive examination.
- Electrical-- Includes major electrical equipment (transformers, breakers, switches, bus bars, etc.), power wire and cable, conduit, cable tray, push-button stations, welding and power receptacles, lighting, grounding, and instrument wire and cable, connection to the grid.

- Instrumentation--Includes process instruments, analyzers, process connections, control house consoles, distributed control systems, and instrument mountings.
- Paint-- Includes paint and coatings for plant equipment, piping, and structures.
- Insulation-- Includes hot, cold and personnel protection insulation for plant equipment and piping.

b) Subcontract Labour Costs

The subcontract labour costs are derived by multiplying estimates of field labour man-hours by a composite "all-in" average wage rate of £50/hr. The direct field labour man-hours are estimated utilising labour efficiency factors appropriate to the location.

The subcontract wage rate includes salaries or wages, payroll burdens, travel/living allowance, construction equipment and tools, field supervision, temporary facilities, and subcontractor overhead and profit.

c) Construction Management

The construction management cost includes the total cost of the construction supervisory staff provided by the construction managing contractor. Included are salaries, allowances, burdens, benefits, overhead and international expenses. This cost is factored based on Jacobs' construction experience with projects of similar magnitude.

d) Temporary Facilities & Other Services

These costs include the construction managing contractor's temporary field offices, office equipment and supplies, warehouse and lay down area, guard and medical facility, heavy haul road and road maintenance.

e) Home Office Engineering Costs

Home office engineering costs are factored from direct field costs based on Jacobs' historical experience with adjustments made to reflect the execution plan of the project. These costs cover the following areas:

- Engineering, design and procurement man-hours, and labour costs;

- Office expenses such as computer costs, reproduction and communication costs and travel;
- Office burdens, benefits and overhead costs.

f) Freight

The direct field material costs are based on worldwide procurement of material. For that material, charges have been included for inland freight to the shipping port, port charges, ocean freight, shipping insurance and inland freight to the project site.

g) Project Managing Contractor

The project managing contractor coordinates and oversees the work being performed by the various licensers, vendors, and engineering or construction contractors performing work on the project. The cost is based on Jacobs' experience with previous similar projects.

h) Contingency

Contingency is a special monetary provision in the estimate to cover uncertainties or unforeseeable elements of time/cost within the scope of the project. Costs associated with the following items are included in contingency:

- Material cost changes (other than scope changes)
- Labour rate changes
- Labour efficiency changes
- Design changes (other than scope changes)
- Schedule slippage
- Estimate methodology inaccuracies

Contingency excludes the following items:

- Scope changes
- Changes in government regulations

- Major design changes
- Catastrophic events
- Extreme weather
- Unknown field conditions
- Labour strikes

An allowance of 15% has been made for the contingency.

i) Escalation

Escalation is considered in detail in the economic analysis and takes into account the number of years required to develop and construct the project

Appendix D2: Details of plant sections and the systems incorporated in each.

(a) Coal Receiving, Storage & Handling

- Receiving
- Storage
- Reclaim
- Conveying

(b) Gasification

- Feed Grinding & Slurrying
- Quench Gasification
- Syngas Scrubbing
- Slag Handling
- Process Primary Water Treating

(c) Fired expander

- CES burners
- Hot expander
- Power generator

(d) HRSG

- Steam superheater coil
- BFW heater coil
- Once through Boiler

(e) Steam Turbine System & Deaerator

- HP/IP/LP Turbines
- Condenser
- Feed heating system
- Deaerator

(f) Desaturator / LT Heat Recovery

- BFW heater

- LP boilers
- Desaturator
- Pumps
- Condensate and Boiler Feed Water

(g) CO_2 Compression

- CO_2 Compression
- Drying System

(h) Air Separation

- Oxygen Plant
- Oxygen Storage
- Nitrogen Compression

(i) Raw Water and Secondary Water Treatment

- RO plant
- Demin plant
- Chemical Dosing Units
- BFW
- Waste water treatment
- Filtration

(j) Electrical

- Transformers
- HV Switch gear
- MV switch gear
- LV switch gear
- MCC
- Electrical distribution

(k) Utilities, Offsites and Other Costs

- Power Distribution
- UPS System

- Communications System
- Steam & Condensate Distribution
- Natural Gas Metering System
- Fire Water
- Plant Control and Management Information System
- Site Preparation
- Roads, Paving, Fencing and Lighting
- General Buildings
- Cooling Water
- Potable/Utility Water
- Raw Water and Waste Water Treatment
- Demineralisation
- Plant & Instrument Air
- Flare
- Sewers
- Sanitary Waste Treating
- Nitrogen System
- Fuel Gas System

(l) Interconnecting piping & large piperacks

- Interconnecting Piping Among Process Units
- Large piperacks
- Supports
- Special hangars etc.

Appendix D3: General execution schedule

The attached schedule is a management level development and execution schedule for the project. It displays the durations and timing of the major engineering, procurement, and construction activities of the project. Major milestones are also indicated on the schedule. The purpose of this overview schedule at this early stage of project development is to provide an indication of the overall duration of the project for planning purposes. It is not intended to be the final execution plan for the project.

The schedule assumes that a preliminary phase, including the selection of process technology licensers and combustion turbine vendor, has been completed and that the contracting philosophy to be employed by the owner includes the preparation of a Front-End Engineering and Design (FEED) package as the next activity after the preliminary phase. During preparation of the FEED package sufficient engineering is completed to define the project in sufficient detail to obtain lump sum turnkey bids from EPC contractors. The time required for the FEED package can vary depending upon the amount of detail developed for the package.

To shorten the overall project schedule, long lead time items can be identified and Request for Quotation (RFQ) packages issued for these items during the FEED package phase. The longest lead time item is typically the Air Separation Unit (ASU). The schedule assumes the ASU is contracted on an LSTK basis and takes 28 months to design, fabricate, deliver and construct. Combustion turbine design, fabrication and delivery time is assumed to be 20 months. These durations will need to be confirmed at the time of order. Typically no actual procurement of the long lead items is done until full project release is issued when environmental permitting is complete, the EPC contractor is selected, and financing has been obtained.

A capital cost estimate is also prepared during the FEED phase to enable the owner to confirm project economics and to use as a check against EPC bid prices to confirm understanding of the project scope.

Also during preparation of the FEED package an Invitation to Bid (ITB) is prepared by the owner and/or the FEED contractor for soliciting lump sum bids from the EPC contractors. The completed FEED package is issued with the ITB to define the project, and time is allowed for preparation of the bids, evaluation by the owner and award/negotiation of an EPC contract.

By the time the EPC contractor is selected and purchase orders for long lead equipment are ready to be issued, other owner activities not shown on the schedule should be completed. These include

environmental permitting, contracting (feedstock, products, operations & maintenance, etc.), governmental approvals if any, formation of the ownership company, and financing. The schedule assumes that the engineering activities are not delayed by these owner activities and that financing is not non-recourse.

Once construction financing has been closed and full EPC release for the project has been given, the long lead time equipment orders can be placed. Detailed engineering is initiated and additional equipment requests for quotations (RFQs) can be prepared. The procurement section of the schedule reflects the estimated time spans from inquiries through final jobsite deliveries for project material and equipment.

The construction portion of the schedule commences with site preparation and the construction of temporary facilities. Effective construction begins when sufficient engineering has been completed (typically 50-60%) to sustain a significant manpower build up. Mechanical completion is defined as the end of the plant construction period. Mechanical completion of individual units occurs over a period of time prior to this point starting with completion of utility systems.

Commissioning and start up are initiated as systems become mechanically complete. Commissioning and testing of individual units/systems occurs over a period of time followed by a short-term performance test for the complete plant to demonstrate achievement of the performance guarantees. The schedule assumes that 50% of design capacity is obtained after three months and 100% after twelve months based on utilizing personnel experienced in starting up and operating gasification plants.

11.0 GLOSSARY

ADT	Acid Dewpoint Temperature
ASU	Air Separation Unit
Capex	Capital expenditure
CCS	Carbon Capture & Storage
CEC	California Energy Commission
CES	Clean Energy Systems Inc
C&I	Control and Instrumentation
CCGT	Combined Cycle Gas Turbine
COS	Carbonyl sulphide
DCS	Distributed Control System
DCF	Discounted Cash Flow
DOE	Department Of Energy (USA)
EGV	Exit Guide Vanes
EOR	Enhanced Oil Recovery
EPC	Engineering Procurement and Construction
EPRI	Electric Power Research Institute
ESD	Emergency Shut Down
ESI	Electricity Supply Industry
ETS	European Trading Scheme
FCI	Fixed Capital Investment
FEED	Front –End Engineering and Design
FGD	Flue Gas Desulphurisation
GCV	Gross Calorific Value

GT	Gas Turbine
HCN	Hydrogen Cyanide
H_2S	Hydrogen Sulphide
HGPI	Hot Gas Path Inspection
HHV	Higher Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HSE	Health & Safety Executive
IGCC	Integrated Gasification Combined Cycle
IGSC	Integrated Gasification Steam Cycle
IGV	Inlet Guide Vane
I/O	Input / Output
IP	Intermediate Pressure
IRR	Internal Rate of Return
LHV	Lower Heating Value
LP	Low Pressure
LSTK	Lump Sum Turn Key
MW_{th}	Mega Watt thermal
NCV	Net Calorific Value
NETL	National Energy Technology Laboratory (USA)
NGCC	Natural Gas Combined Cycle
NPV	Net Present Value
OEM	Original Equipment Manufacturer
O&M	Operating & Maintenance
Opex	Operating Expenditure

PFD	Process Flow Diagram
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume diluted to oxygen %.
RFQ	Request for Quotation
ROI	Return On Investment
ROM	Run Of Mine
ST	Steam Turbine
TCE	Total Capital Employed
TIT	Turbine Inlet Temperature
WC	Working Capital
WDT	Water Dewpoint Temperature
WTP	Water Treatment Plant

12.0 REFERENCES

[1] BERR, *CCS demonstrator will put UK ahead in global race for clean coal*, BERR website news listings, NDS, 9th October 2007 Last retrieved from http://nds.coi.gov.uk/environment/fullDetail.asp?ReleaseID=321108&NewsAreaID=2&NavigatedFromDepartment=True on 1st October 2008.

[2] ZENG, *ZENG AS ZeroEemission Norwegian gas homepage*, last retrieved from http://www.zeng.no/ on 1st October 2008.

[3] LAND, *Monitor cold-end corrosion and sulphuric acid aerosol emission in oil/coal fired boilers* webpage, last retrieved from http://www.landinst.com/combustion/products/combustion/440_acid_dewpoint.htm on 1st October 2008

[4] Clean Energy Systems, *Durability and Reliability Demonstration of a Near-zero-emission Power Plant,* California Energy Commission, USA, July 2006

[5] J. L. Klara, National Energy Technology Laboratory, Gasification Technologies Council Annual Conference, October 2007.

[6] Metz, B. and IPCC, *IPCC special report on carbon dioxide capture and storage*, Cambridge University Press, New York, 2005

[7] Vince White, International Oxy-Combustion Research Network, 2nd Workshop, Windsor, CT, USA , January, 2007

[8] Crovetto,R.; Mather, A. E., "Evaluation of Solubility Data of the System CO_2 + H_2O from 273 K to the critical Point of Water", in "Carbon Dioxide in Water and Aqueous Electrolyte Solutions", IUPAC Solubility Series, Vol 62, Scharlin, P. (ed), Oxford University Press, Oxford (1994) 5-12.

[9] Battino, R.; “Sulphur Dioxide, Chlorine, Fluorine and Chlorine Oxides, IUPAC Solubility Data Series, Vol 12, Young, C. L. (ed), Pergamon Press, Oxford (1983) 3-5.

[10] Wagner, W.; Pruss, A.; “The IAPWS Formulation 1995 for the Thermodynamic Properties of Ordinary Water Substance for General and Scientific Use”, J. Phys. Chem. Ref. Data, 31 (2002) 387-535

[11] Zawisza, A.; Malesinska, B.; J. Chem. Eng. Data 26 (1981) 388-391.

[12] Rumpf, B.; Maurer, G.; Fluid Phase Equilib. 81 (1992) 241-260.

[13] Bosen, A.; Engels, H.; Fluid Phase Equilibria 43 (1988) 213-230.

Acknowledgements

This Report is dedicated to the memory of Dave Robson who pioneered and completed the first successfully converged solution of a full flow scheme simulator model for IGSC. He passed away before the final results of his work could be evaluated.

The Consortium would like to thank the following organisations that contributed over and above their original commitments:

Air Products
BOC (Linde)
MAN
SPX Dehydration & Filtration.

The consortium would also like to thank BERR for their financial contribution.

1