COVER NOTE to Key Knowledge Document

Report title: Drax BECCS Project – CO_2 Compression and Dehydration Unit Report

This report is part of the work delivered under project CS359, "Negative CO_2 emissions from full scale BECCS utilising non-amine CCS chemistry", which is part of BEIS CCUS Innovation call.

The project

The project is looking at implementing CCL's technology onto existing infrastructure at Drax Power Station, applying it to BECCS (Bio-energy with Carbon Capture and Storage). Aspects of the project include scale-up, testing alternative gas-liquid contactors and feasibility studies to support the business case for full scale BECCS.

Summary of this KKD

After capturing the CO_2 from the flue gas and releasing it in the stripper at elevated pressure the CO_2 pressure of the product gas needs to be increased to pipeline pressure and CO_2 needs to be dehydrated to allow safe transport through a pipeline towards a sequestration site.
The CO_2 compression and dehydration are quite independent on the CO_2 capture technology apart from at what pressure the CO_2 is released initially. Different compression and dehydration technologies and configuration were evaluated to inform the optimal solution for Drax's boundary conditions.

The final project report is due April 2022.

Signed

Caspar Schoolderman (Project Director)

Drax BECCS Project

CO2 Compression and Dehydration Unit Stage 2 Report

Drax Corporate Limited

01 July 2021

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Document history

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Contents

Tables

Figures

1. Executive Summary

According to the recent IPCC summary for policy makers (Oct 2018), Bio-energy with Carbon Capture and Storage (BECCS) is one of the key methodologies required to keep the world on a 1.5°C greenhouse gas emission pathway. The BECCS Project being developed by Drax (with its partners National Grid and Equinor) will result in carbon being removed from the atmosphere with a negative carbon factor of around 470kgCO_2/MWh.

The BECCS Project is designed to capture up to 4 million tonnes per annum (mtpa) of CO_2 from one of its converted biomass units (Unit 2) and has a net capacity of 645 MW. The captured CO_2 will be compressed and dehydrated and sent via the National Grid CO_2 pipeline to a geological storage site under the North Sea.

Drax commissioned several studies covering a wide range of options across the full chain. These include the optimisation of process chemistry for the capture technology; re-purposing of the Flue Gas Desulphurisation Infrastructure for carbon capture; and a feasibility study into the transport and storage of the captured CO_2. One of the feasibility studies includes the optimum design of the CO_2 compression, dehydration and CHP packages. Drax commissioned Atkins to undertake this work in the following two stages:

- Stage 1 covering the technology options review and selection, as well as initiating data gathering from potential technology suppliers.
- Stage 2 report covering the conceptual design for the selected options. This includes preliminary HYSYS modelling, CAPEX and OPEX estimates (Class IV) for each of the selected options.[1]

This report presents the results of Stage 2 including all key concept design deliverables for the CO_2 compression and dehydration options. The following presents a summary of the results:

CO_2 Compression

Following Stage 1 further clarification was required prior to commencing Stage 2. The results of this analysis were presented in a Stage 2a interim design review and are summarised below:

Employing a pump to replace one or more compression stages:

- 15 – 20% higher CAPEX due to higher equipment cost and larger footprint
- 2.5 – 4% lower OPEX due to the lower total absorbed power

The resultant simple payback period is up to 9 years without considering increased maintenance cost and will result in added complexity. Hence, Atkins recommends not carrying forward this option to concept design.

Comparing an ‘in-line’ compressor with integrally geared:

- ~10% higher CAPEX for the in-line compressor due to higher equipment cost and larger footprint (up to 25%).
- A marginally higher OPEX is expected for the in-line compressor (following optimisation as recommended by compressor supplier) due to its lower efficiency and therefore higher absorbed power requirements.
- There is no difference in reliability / availability which is key learning established during the Stage 2a analysis (confirmed by compressor suppliers).
- One supplier suggested the use of an in-line compressor for the 1 x 100% train configuration (4 mtpa), due to power limitations of the drive gear when using an integrally geared machine.

Only integrally geared compressors will be developed during Stage 2 due to the higher costs associated with an in-line machine. Hence, the following four cases were further developed to concept design level:

Case 1:	2 x 50% Integrally geared compressors for 0.6 barg inlet pressure
Case 2:	2 x 50% Integrally geared compressors for 2 barg inlet pressure
Case 3:	2 x 50% Integrally geared compressors for 3 barg inlet pressure
Case 4:	1 x 100% Integrally geared compressor for 0.6 barg inlet pressure

The CO_2 compression conceptual design deliverables were developed for the above cases and used as the basis for the cost estimate. The cost estimate is largely based on equipment costs provided by suppliers. The results

[1] It should be noted that exact CAPEX and OPEX figures will typically not be shared if they have been obtained from a vendor, however the costs will be shown in a ratio to one another to allow a comparison between the scenarios considered.

were analysed and used to inform the technology assessments carried out at the end of Stage 2. The following is a summary of the Stage 2 results for CO_2 compression:

- Integrally geared and inline compression technologies provide viable options for the required CO_2 compression duty. However, integrally geared compressors are the favoured technology and offer savings in CAPEX, OPEX (following optimisation), efficiency and footprint. Both types of compressors offer the same high reliability and availability of around 98.5%.
- Operating the CO_2 stripper at higher operating pressures (therefore increasing suction pressure to the compressor to 3 barg) significantly reduces compressor's CAPEX and OPEX whilst also reducing the capture plant heat demand.
- Electrical drives for compressors present low CAPEX.
- The 2 x 50% train configuration (2 mtpa per train) presents ~1.7 times higher CAPEX, compared to a single 100% train configuration (4 mtpa).
- The 2 x 50% train arrangement offers significant OPEX advantages over 1 x 100% configuration if turndown below 50% is required for significant periods of time, since lower levels of gas recirculation are required. The annual power costs double when using a single train arrangement at turndowns of 30 – 50% compared to the two-train configuration.

Atkins recommends that further study is carried out to establish if 2 x 50% or 1 x 100% compression trains are preferred based on economic modelling that considers the annual duration where turndown below 50% is required. This recommendation is made as there is significant additional CAPEX investment required for the 2 x 50% configuration to deliver an improved OPEX over the turndown range.

Should C-Capture technology be utilised for the project then operation of the stripper at 3 barg is recommended as this lowers the overall CAPEX and OPEX for the compression train. This also indicates that higher stripper operating pressures are preferred for other capture technologies, although it should be noted a pressure of 3 barg may not be favoured for proprietary amine capture technology due to degradation issues.

CO_2 Dehydration

The following dehydration technology options were selected to be carried forward for Stage 2 concept design development and cost estimation:

Case 1: 2 x 50% Silica Gel adsorption dehydration

Case 2: 2 x 50% Molecular sieve adsorption dehydration

Case 3: 2 x 50% TEG absorption dehydration

2 x 50% train arrangement has been assumed as the base case to maintain the overall plant flexibility with both CO_2 capture plant and compression units likely to be split into 2 x 50% trains. The cost estimate is based on supplier information (as listed above), HYSYS modelling and in-house data.

The following is a summary of the Stage 2 results for CO_2 dehydration:

- All three CO_2 dehydration technologies (silica gel, molecular sieve and TEG) provide viable options for the required CO_2 capacity and are available products from a range of vendors.
- All three CO_2 dehydration technologies (silica gel, molecular sieve and TEG) offer high availability (above 98%) and can achieve the required minimum turndown of 33%.
- Absorption processes using TEG are less susceptible to impurities than desiccant beds.
- TEG units are often preferred by the CO_2 compressor vendors, due to their robustness against pressure ramps which can be seen at start-up and shutdown procedures. In comparison, an adsorption package will need to be completely isolated from the compressor for shutdown and start-up, as pressure ramps are not acceptable to the drier bed.
- The three CO_2 dehydration processes offer roughly the same CAPEX. Absorption with TEG has the highest CAPEX with the lowest OPEX per year. Adsorption with silica gel has the lowest CAPEX and a higher OPEX per year.
- Adsorption with molecular sieve can offer the lowest product moisture content of 1 ppmv but requires significant heat and power and thus the highest OPEX. The CAPEX is comparable to the other two technologies.

- The OPEX is based on LP steam and additional electrical heating. The study shows this as an economic option reducing OPEX per year (in the case of molecular sieve). The resultant simple payback is less than one-year for adsorption with molecular sieve; for other options it may be up to three years.
- The option of recovering some of the heat of compression in the spent bed regeneration process would deliver an overall benefit with the increased CAPEX achieving less than a three-year simple payback.

Atkins recommend carrying forward both absorption and adsorption dehydration technologies to the next stage for a more detailed design and cost assessment. Silica Gel and TEG are preferred if significant value cannot be gained for the lower CO_2 water content (only achievable if molecular sieves are selected) from the transportation operator.

2. Introduction

Drax Power Station is a 4000MW, predominantly biomass fired power station located near York, in North Yorkshire, owned by Drax Group PLC ("Drax"). Drax Power Station has historically burned up to 10MTe's of coal per annum but since 2004 has been utilising biomass, initially at low percentages but culminating last year in a burn of c.7MTe's of biomass via the conversion of four of the 645MW units. The Power Station is the largest, cleanest and most efficient biomass plant in the UK and provides up to 7% of the UK's electricity.

Drax Power Station are now investigating the potential to further decarbonise and incorporate a carbon capture plant to process the flue gas from Unit 2, one of the biomass converted units. The captured carbon dioxide would be compressed and dehydrated to meet a pipeline specification for export via the National Grid CO_2 transportation system to a geological storage under the North Sea.

Capturing the carbon from Unit 2 would allow electricity to be generated with negative carbon emissions due to the carbon neutrality of the biomass fuel. This project in its entirety being developed by Drax and its partners (Pipeline development by National Grid Ventures and the Geological Storage development by Equinor) is referred to as 'The BECCS Project'. Drax have estimated the addition of carbon capture to a single Drax generating unit is expected to capture between 2.5Mte/y and 4Mte/y of carbon dioxide with a daily capacity of 10,960 tpd. This would allow generation of electricity with a negative carbon factor of ~ -470kgCO_2/MWh.

In pursuit of the BECCS project Drax have identified three discreet but closely linked work streams:

- A research and development project to determine optimal chemistry and develop a process design which maximises capture efficiency of the process, feeding information and design data for the absorber works into work stream '2'.
- A carbon capture facility located on Unit 2 within the design based upon re-purposing the Flue Gas Desulphurisation Infrastructure and space, building upon the design outputs from workstream '1' this would also include the ducting, booster fans and gas/gas heater infrastructure, electrical and C&I locations, and common plant and areas such as FGD Waste Water Treatment plant and storage locations. Battery limit for the facility will be the compression stage prior to transport & storage or utilisation.
- A Feasibility study with selected partner/s into the transport and storage of the CO2 captured by the carbon capture facility.

The second of these three work streams include the Pre-Front End Engineering Design (Pre-FEED) Feasibility study to determine the optimum design of CO_2 compression and dehumidification equipment that Atkins have been commissioned to undertake. The study has been delivered in two stages:

1. Stage 1 covering the technology options review and selection, as well as initiating data gathering from potential technology suppliers.
2. Stage 2 report will cover conceptual design for the selected options. This includes preliminary HYSYS modelling, CAPEX and OPEX estimates for each of the selected options.

Stage 1 work was successful in engaging with a range of equipment suppliers for both compression and dehydration equipment with a significant amount of data being fed into the technology evaluation and selection process. This provided a good basis for down selection of technology options, that was undertaken in collaboration with Drax at the Stage 1 review. However, further clarification was needed to fully evaluate dense phase pumping and in-line compression options. These clarifications were made in the early part of Stage 2 to confirm if these options were to be carried forward to conceptual design, under the title of Stage 2a (see Section 4). The options that were selected to be carried forward for Stage 2 concept design development and cost estimation were as detailed on the following page.

CO_2 Compression

1. 2 x 50% Integrally geared compressors for 0.6 barg inlet pressure
2. 2 x 50% Integrally geared compressors for 2 barg inlet pressure
3. 2 x 50% Integrally geared compressors for 3 barg inlet pressure
4. 1 x 100% Integrally geared compressor for 0.6 barg inlet pressure

CO_2 Dehydration

1. 2 x 50% Silica Gel adsorption dehydration.
2. 2 x 50% TEG absorption dehydration.
3. 2 x 50% Molecular sieve adsorption dehydration (agreed after the stage 1 review).

The purpose of the Stage 2 study is to develop the concept design to:

- Enable main plant equipment to be identified.
- Confirm vendor supply scope and CAPEX estimates for the various options.
- Confirm vendor plant performance data for the various options.
- Develop overall PFDs and H&MBs.
- Identify main plant equipment within and outside vendor supply scope.
- Develop design basis and sizing for main equipment within and outside vendor scope.
- Develop capital cost estimates for the various options to AACE Class IV.
- Estimate utility requirements and develop utility summaries.
- Develop OPEX estimates for the various options.
- Estimate plant footprint requirements.
- Produce a desktop HAZID/ENVID for the compression and dehydration units.
- Develop operations and maintenance philosophy.

This report details the results of the Stage 2 study work and presents the concept design for the selected compression and dehydration options, as detailed above.

The Stage 2 report also includes a summary of the findings of the following technology assessments:

- Heat of compression
- Operating pressure of stripper
- Compressor drives
- Construction availability assessment
- Contaminants impact
- Flexible operation
- Reliability, availability and maintenance assessment

The report concludes by providing a list of recommendations based on the findings of the Stage 1 and Stage 2 study work.

3. Basis of Study

The Drax Functional Specification [1] set out the basis for the Atkins CO_2 Compression Study, the key requirements and basis for the study are summarised below.

3.1. Required CO_2 Pipeline Specification

The Carbon Dioxide produced at Drax Power Station will likely be distributed via a pipeline owned and operated by National Grid. National Grid have produced a specification NGC/SP/PIP/25 which defines the Carbon Dioxide quality requirements for pipeline transportation.

The required pipeline entry pressure shall be 135 barg and we have assumed a maximum acceptable CO_2 temperature of 45°C.

The design of the compressors/pumps and dehydration units shall meet the above criteria.

3.2. Capture Process

Drax is considering the scale up of the C-Capture process currently being trialled at Drax Power Station with a 1tpd pilot scale unit. The C-Capture process uses a novel absorption solvent which is believed to have benefits over more conventional amine based absorption processes.

The Functional Specification [1] was based around the use of the C-Capture process, however subsequent discussion with Drax have identified that they are also considering amine based absorption processes. Hence, amine based technologies are also considered as part of the technical assessments associated with operating pressure of stripper and impact on contaminants.

The CO_2 supplied to the compression unit shall have the following conditions [1]:

- Temperature 30°C.
- Mol. Fraction 0.962 CO2
- Mol. Fraction 0.038 H2O
- Inlet pressure (based on operating pressure of the stripper):
  - The stripper operates at atmospheric pressure (not considered further due to higher associated costs)
  - The stripper operates at 0.6 barg (applicable to both amine based technology and C-Capture)
  - The stripper operates at 2.0 barg
  - The stripper operates at 3.0 barg
- It is anticipated that the fly ash solids will be removed by the Carbon Capture plant, but other contaminants may be carried over into the CO_2 collected. In addition, small amounts of VOC from the capture process may be carried over from the stripper.

The contaminants present in the CO_2 supplied to the compression and dehydration processes have been reviewed based on the Heat and Mass Balance Data provided by C-Capture [2].

3.3. Turndown

The compression and dehydration design shall be capable of turn down to 50%, reflective of single capture train operation and 33% reflective of the generating unit minimum stable generation. The impact on operating efficiency shall be considered with turndown being affected through:

- Variable speed drives
- Inlet guide vane control
- Train sizing/capacity
- Other technologies

4. Stage 2A Interim Design Review

4.1. Compression & pumping case

Employing a pump with a lower parasitic workload to replace one or more compression stages could potentially lead to energy savings and lower OPEX. This stems from the fact that, if the pressure increase applied on a fluid is the same, the enthalpy increase is much less in the liquid state than in the gas state, which would result in less shaft power input for the liquid state. Therefore, one option is to liquefy CO_2 at a supercritical pressure. In this strategy, CO_2 is first pressurised to a supercritical pressure by multistage compression, liquefied and then pumped to the battery limit pressure of 135 barg. This configuration is presented in Figure 4-1.

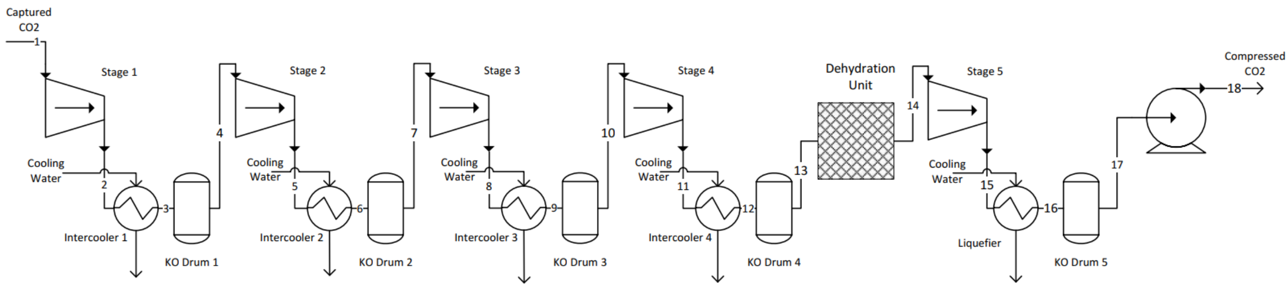


Figure 4-1 - Multistage integrally geared compression & pumping

Two compression & pump cases were examined during stage 2A, namely:

- Case 1B: 2 x 50% at 0.6 barg suction pressure using a 5-stage integrally geared compressor and a 5-stage dense phase pump
- Case 2B: 2 x 50% at 2 barg suction pressure using a 5-stage stage integrally geared compressor and a 6-stage dense phase pump.

It was assumed that the pressure at the pump inlet is between 80 and 90 barg. The above cases were compared to the integrally geared multistage compression only cases and the results are presented in Table 4-1.

Table 4-1 - Comparison of compression versus compression + pumping for two different suction pressures

	Case 1	Case 1B	Case 2	Case 2B
Data Source	Vendor / HYSYS	Vendor / HYSYS	Vendor / HYSYS	Vendor / HYSYS
Train Arrangement	2 x 50%	2 x 50%	2 x 50%	2 x 50%
Compression stages	6	5	6	5
Pump stages	-	5	-	6
Compression suction	0.6 barg / 30 °C	0.6 barg / 30 °C	2 barg / 30 °C	2 barg / 30 °C
Inlet of Pumping stage	-	86 barg / 32 °C	-	85 barg / 17.5 – 37.5 °C
Discharge	135 barg / 128.8°C	135 barg / 45°C	135 barg / 117°C	135 barg / 24-57°C
Intercoolers	4	5	4	5
Aftercoolers	1	0	1	0
Footprint (per train)	16.5 x 11.5	21.3 x 14.1	12.5 x 10.5	20 x 16

	Case 1	Case 1B	Case 2	Case 2B
Absorbed power (total)	40.8 MW	38.7 MW	37.2 MW	36.3 MW
Cooling water requirements (total)	5,506 m^3	5,631 m^3	5,101 m^3	5,004 m^3
Availability/Reliability	99% / 99.5%	98% / 99%	99% / 99.5%	98% / 99%

Figure 4-2 presents a comparison of the installed CAPEX for the above cases. The CAPEX for cases 2-4 are shown as a percentage of the CAPEX for case 1. It is notable that for compression + pumping cases resulted in higher CAPEX. Specifically, case 1B and 2B presented ~20% and ~15% higher CAPEX compared to cases 1 and 2, respectively. It should be noted that the reason for higher cost difference between cases 1/1B stems from the fact that two different vendors were contacted for the compression + pumping case and their design is not integrated in one package. In contrast, cases 2 and 2B are both integrated packages from the same vendor.

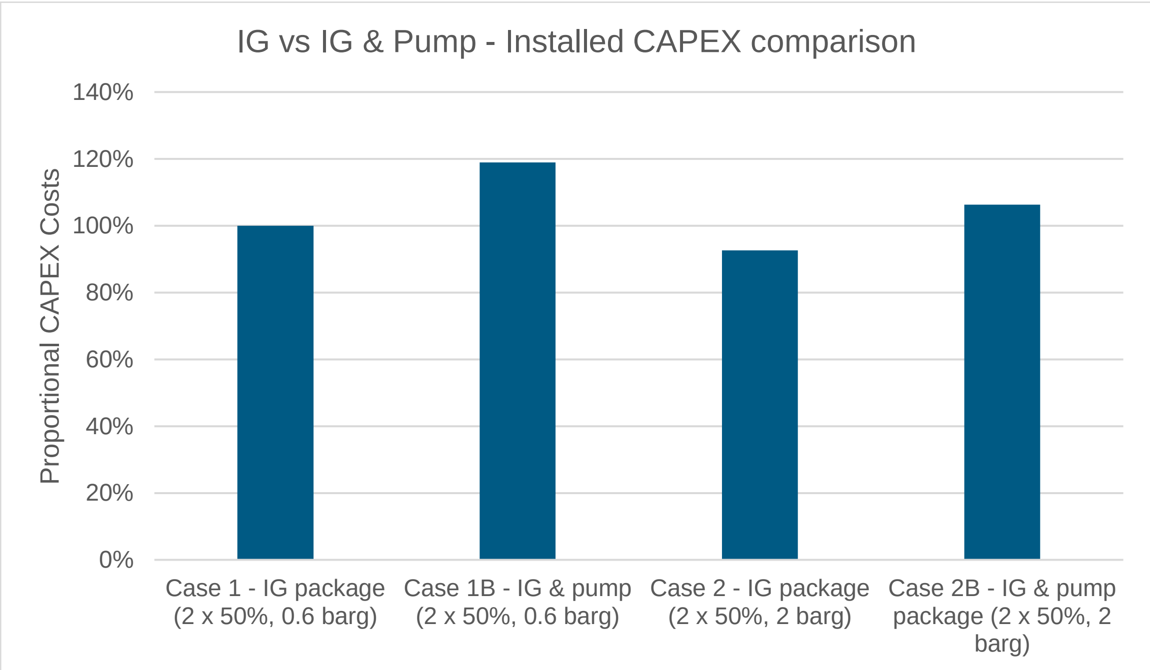


Figure 4-2 - Installed CAPEX comparison for the integrally geared versus the IG + pumping cases

Figure 4-3 presents a comparison of the OPEX calculated from the absorbed power and cooling water requirements for each case. The OPEX for each case is demonstrated as a percentage of the OPEX cost for case 1. As expected, both Case 1B and 2B resulted in lower power requirements and as such lower OPEX, compared to cases 1 and 2, respectively. Specifically, compression + pumping case 1B presented a 4% reduction in annual OPEX, mainly due to the lower absorbed energy required (38.7 MW instead of 40.8 MW). Cooling water requirements are shown in light blue on the graph and were similar for both cases. Similarly, for the 2 barg suction pressure (case 2B), a reduction of 2.5% in annual OPEX was evident, also stemming from the lower absorbed power requirements (36.3MW compared to 37.2 MW).

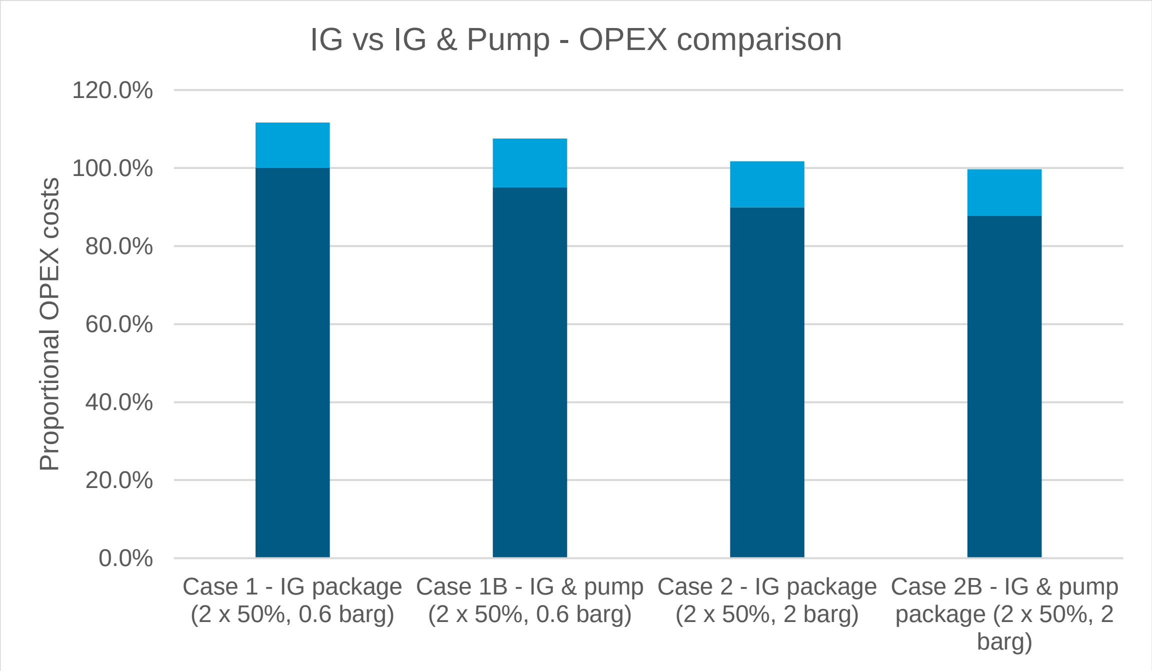


Figure 4-3 - OPEX comparison for the IG versus the IG + Pumping cases

For cases 1B and 2B the OPEX savings compared to cases 1 and 2 result in a simple payback for the increased installed CAPEX investments of <10 years for both. However, it is expected that the payback period would be longer when including annual maintenance costs, since two different units will require maintenance for the compression + pumping case. As such, the long simple payback period combined with the added complexity and significantly larger footprint of the compression + pumping cases, suggest that this configuration is not to be examined further.

4.2. Integrally geared vs in-line compressors

A typical integrally-geared centrifugal compression process is split into several stages, separated into groups of two or perhaps one stage. Each of the stage groups is connected to a single pinion. This setup makes it possible to apply optimal speeds to each two-stage pairing. Such optimization is not possible on a single-shaft machine, because all of the stages run at the same speed, since all impellers are on this single shaft.

Generally, a single-shaft in-line compressor requires a bigger footprint than an integrally geared solution. Typically, the arrangement consists of a low pressure (LP) and a high pressure (HP) casing featuring more impellers than comparable integrally geared machines. LP and HP casings are connected directly or via an intermediate gear and coupling.

Six compressor vendors with previous CCS experience were contacted throughout the duration of this study, however, only one vendor offered an in-line multistage compressor for this application. As such, a comparison between those two machines offered by this vendor is presented in Table 4-2.

Table 4-2 - Comparison of integrally geared vs inline centrifugal compressor

	Case 2	Case 2C
Data Source	Vendor / HYSYS	Vendor / HYSYS
Train Arrangement	2 x 50%	2 x 50%
Number of Stages	6	2 LP horizontal split compressor[2] 2 HP vertically split barrel compressor
Inlet Conditions	2 barg / 30 °C	2 barg / 30 °C
Discharge Conditions	135 barg / 117 °C	135 barg / 113 °C
Intercoolers	4	3
Aftercoolers	1	1
Footprint (per train)	12.5 x 10.5	14.5 x 12
Absorbed power (total)	37.2 MW	36 MW
Cooling water requirements (total)	5,101 m^3	5,004 m^3
Turndown to (per train) - IGVs[3]	80%	80% (70% when using VSDs)
Availability / Reliability	99% / 99.5%	99% / 99.5%

Figure 4-4 presents a comparison of installed CAPEX between the integrally geared and in line centrifugal compressors, according to the vendor's quotes. The installed cost for the in-line centrifugal compression unit is shown as a percentage of the installed cost for the integrally geared compression unit which is estimated to be approximately £32 million. It is notable that even though there are fewer stages and intercoolers in the in line compressor, it presents a 10% higher CAPEX compared to the integrally geared machine. This is due to there being two separate pressure casings and off skid inter coolers requiring additional piping and civils costs.

[2] There are some safety considerations around the horizontal split due to its long seal length compared to the radial split casing, according to Atkins's past experience, however, use on the LP compressor reduces this risk.
[3] IGVs: Inlet Guide Vanes

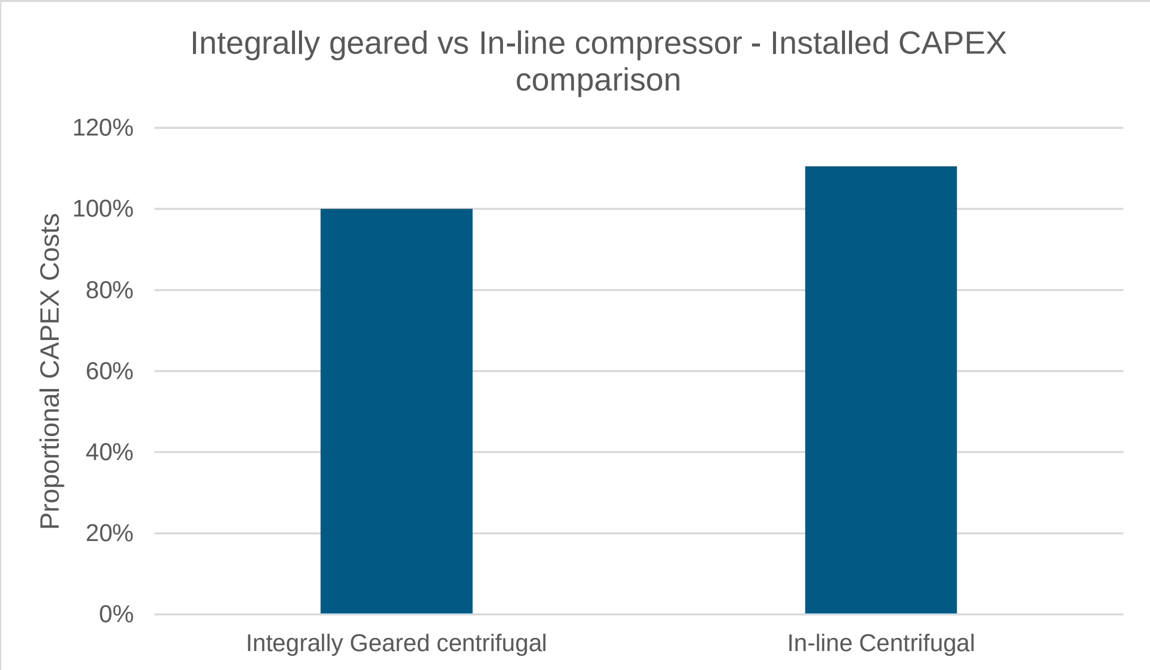


Figure 4-4 - Installed CAPEX comparison for the integrally geared versus the in-line compressor case

Figure 4-5 presents a comparison of annual OPEX between the integrally geared and in line centrifugal compressors, according to information received from the vendor in relation to absorbed power. Cooling water requirements were calculated using HYSYS modelling. In is notable that the in line configuration resulted in annual OPEX savings as a result of the 3.5% lower absorbed power requirements compared to the integrally geared compressor. However, it should be noted that the vendor made it clear that further optimisation of the integrally geared compressor would result in the absorbed power being similar for both compressor types and as such there would be no significant difference in the annual OPEX figures.

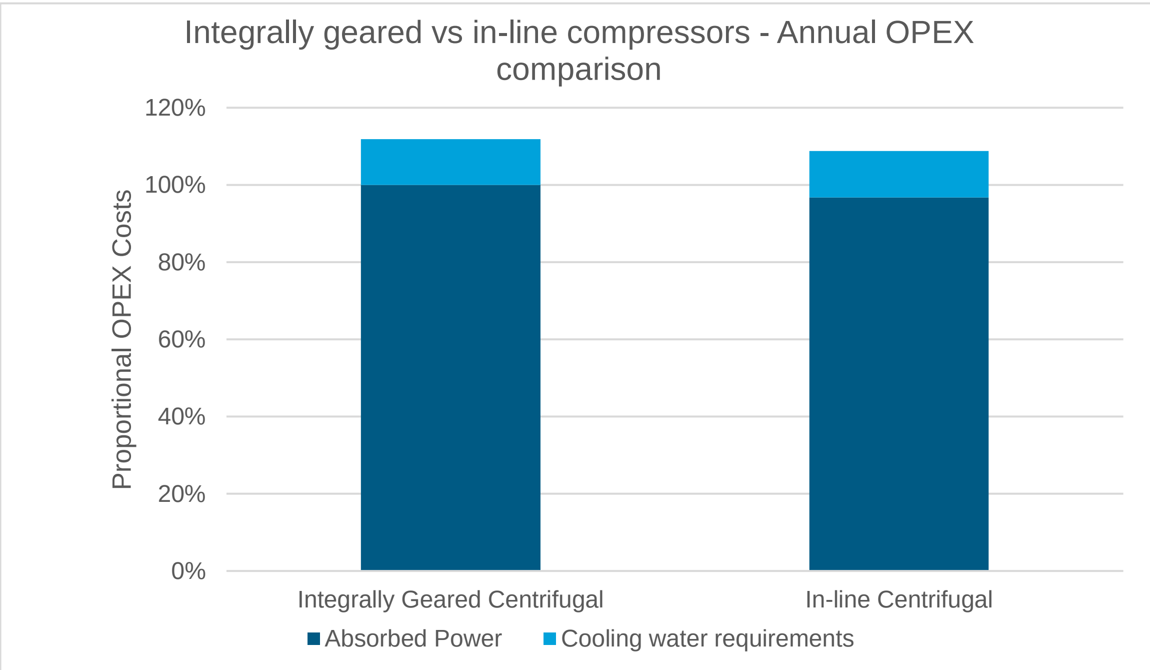


Figure 4-5 - OPEX comparison for the integrally geared versus the in-line compressor case

4.3. Stage 2A Summary and Recommendations

Stage 2A compared the following cases:

- Integrally geared compressor vs integrally geared compressor + pumping
- Integrally geared compressor vs in line compressor

Table 4-3 presents a summary of the findings and consequent recommendations.

Table 4-3 - Summary of findings and recommendations from Stage 2A study

Multistage IG compression vs multistage IG compression + pumping	
Summary of findings	• CAPEX: 15-20% higher for the compressor + pumping case • OPEX: 2.5-4% lower for the compression + pumping case, due to the lower total absorbed power required (~3% savings in power requirements). Similar cooling water requirements for both cases • Simple payback: 6.5-9 years without considering increased maintenance costs for the compression + pumping case • Complexity: The dense phase pump represents an additional unit operation that adds on to the overall complexity of the system • Process equipment: Compression + pump systems would require an additional CO_2 accumulator, acting as a holding vessel during pump recirculation. This can be eliminated in the compression only case • Footprint: 40-60% smaller footprint for the compressor only case • Performance guarantee for single compressor duty more attractive for Client and Execution Contractor than the interface between guarantees for compressor duty and subsequent pump duty. • Lower overall availability/reliability for compression + pumping case, due to two different type of machines (97% compared to 98.5%)
Recommendations	• Atkins suggestion: 2.5-4% OPEX savings do not justify the selection of a compression + pump configuration due to increased CAPEX, higher maintenance costs, added complexity and larger footprint. Atkins recommends not to proceed with this case further
Integrally geared vs in line centrifugal compressors	
Summary of findings	• CAPEX: ~10% higher for the in-line compressor • OPEX: ~3% lower for the in-line compressor, due to the lower total absorbed power required (~3% savings in power requirements). However, optimisation would reduce the absorbed power required to similar levels (or even lower) as in the in-line compressor case. Similar cooling water requirements for both cases. • Simple payback: ~5 years, assuming that the difference in absorbed power remains the same after optimisation of the integrally geared compressor • Footprint: ~25% smaller footprint for the integrally geared compressor • Total Reliability/Availability: 98.5% - no difference between the two compressors designs (confirmed by vendors) • Only one vendor out of the six contacted offered an in-line compressor for the BECCS application. This could potentially create issues during procurement. Lack of competition could also result in high CAPEX
Recommendations	• Vendor suggestion: Use of an in-line compressor for the 1 x 100% train configuration, due to power limitations of the gear when using an integrally geared machine. For the 2 x 50% case, the integrally geared compressor is generally the preferred option, as it presents lower CAPEX, smaller footprint and similar OPEX (after optimisation). • Atkins suggestion: Continue to allow for the inline compressor option for a 1 x 100% train selection, as some vendors may prefer to offer this solution and it presents similar performance characteristics with the integrally geared machine. However, this option may be down-selected during procurement exercise. Atkins recommends integrally geared compressors for the 2 x 50% case.

5. Concept Design

5.1. Selected Options

During Stage 1 Atkins approached a wide range of equipment vendors of compressor, super critical pump and dehydration equipment. Whilst not all vendors responded those that did have engaged very positively and provided valuable input to the study. The vendor data received covered all the selected technologies and train sizes enabling a good evaluation of cost and performance to be made.

During Stage 1, the supersonic shockwave technology was ruled out, due to the commercial and technological disadvantages it presented compared to the well-established inline/integrally geared compressors.

During Stage 2A, the inline compressor and the compressor + pump cases were examined, and the results are presented in Section 4.

The Stage 1 findings were updated using the findings from stage 2A and are summarised in Table 5-1.

Table 5-1 - Summary of findings of stage 1 preliminary design for compression

	In-line single shaft centrifugal	Integrally geared multishaft centrifugal	Supersonic shockwave	Compressor + pump
Readiness	TRL 9	TRL 9	TRL 8	TRL 9, but usually used for higher outlet pressures
CAPEX[4]	111%	100%	156%	113-128% when using IG compressors
OPEX[5]	96%	100%[5]	• No heat recovery: 178% • With recovery: 130%	96%[6]
Operability	High. Well established	High. Well Established	Unknown	More complexity due to the addition of the pump
Availability/ Reliability (total)	98.5% Well established technology with various installed references	98.5% Well established technology with various installed references	Unknown - Not commercial yet	97% Well established technologies, however, the additional unit results in a small drop in total %
Turndown to	• With VFDs: 70% • With recycle: 0% • Lower turndown can be achieved with IGVs for the	• With IGVs: 75% • With recycle: 0% • Lower turndown can be achieved with IGVs for the	• With IGVs: 80% • No info on recycle • Only the 100% train arrangement is possible, resulting in lower flexibility	• With IGVs: 75% • With recycle: 0% • Lower turndown can be achieved with IGVs for the

[4] CAPEX and OPEX values are shown as a percentage of the integrally geared compressor option for comparison.
[5] Due to time constraints, no optimisation of the integrally geared machine was conducted. It is anticipated that after optimisation, both inline and integrally geared machines will present similar OPEX.
[6] Compressor + pump case used integrally geared compressors for the compression stages. No optimisation of the integrally geared machine was conducted. It is anticipated that after optimisation, the compressor + pump case will result in 2.5-4% savings compared to the inline/integrally geared only cases.

	In-line single shaft centrifugal	Integrally geared multishaft centrifugal	Supersonic shockwave	Compressor + pump
	50% and 33% train arrangements	50% and 33% train arrangements	compared to other compressors	50% and 33% train arrangements
Footprint (m x m)	14.5 x 12 (supplied by vendor)	12.5 x 10.5 (supplied by vendor)	Very compact due to high compression efficiency	20 x 16 (supplied by vendor)
Risk	Low – well established technology	Low – well established technology	High risk as only single reference	Higher compared to compression only solution, mainly due to not being proven at low discharge pressure. Also, the pump adds extra complexity

The dehydration technology findings of the Stage 1 study are summarised in Table 5-2.

Table 5-2 - Summary of findings of stage 1 preliminary design for dehydration

	Adsorption – Activated alumina	Adsorption – Silica gel	Adsorption – Molecular sieves	Absorption – TEG
Readiness	TRL9 (Commercial)	TRL9 (Commercial)	TRL9 (Commercial)	TRL9 (Commercial)
CAPEX[7]	100%	100%	100%	66%
OPEX[6]	122%	100%	165 – 225%	33 – 66%
Operability	Desiccant life = 2 yr. Agglomerated clumps Sensitive to contaminants	Desiccant life = 5 yr Agglomerated clumps Sensitive to contaminants	Desiccant life = 3-4 yr Agglomerated clumps Sensitive to contaminants	TEG entrainment in CO_2; Lower CO_2 capture rate (0.2% potentially vented)
Reliability	Stable process with potential operability issues	Stable process with potential operability issues	Stable process with potential operability issues	Stable process with potential operability issues
Turndown	30% turndown	30% turndown	30% turndown	10% turndown
Footprint				Smaller than adsorption
Risk	Proven with CO_2	Proven with CO_2	Proven with CO_2	Proven with CO_2

[7] CAPEX and OPEX values are taken as a percentage of the Adsorption – Silica gel scenario costs as a basis for comparison.

Taking the above findings into consideration, the options that were selected to be carried forward for Stage 2 concept design development and cost estimation were:

CO_2 Compression

1. 2 x 50% Integrally geared compressors for 0.6 barg inlet pressure
2. 2 x 50% Integrally geared compressors for 2 barg inlet pressure
3. 2 x 50% Integrally geared compressors for 3 barg inlet pressure
4. 1 x 100% Integrally geared compressor for 0.6 barg inlet pressure

CO_2 Dehydration

1. 2 x 50% Silica Gel adsorption dehydration.
2. 2 x 50% TEG absorption dehydration.
3. 2 x 50% Molecular sieve adsorption dehydration (agreed after the stage 1 review).

5.2. Basis of Design

The following section summarises the basis of design for the CO_2 compression plant, which has been presented to and discussed with the compressor and dehydration technology suppliers for their initial performance and cost estimates.

- Design CO_2 flowrate: 10,960 tonnes / day net throughput (~4 mtpa CO_2)
- Compression:
    - Feed composition (mol):
        - 0.962 CO_2
        - 0.038 H_2O
        - It is anticipated that the fly ash solids will be removed by the Carbon Capture plant, but other contaminants may be carried over into the CO_2 collected. In addition, small amounts of VOC from the capture process may be carried over from the stripper. Suppliers were asked to comment on the likely impact of such contaminants on the CO_2 compressor.
    - Suction pressure:
        - 0.6 barg
        - 2 barg
        - 3 barg
    - Suction Temperature: 30°C
    - Discharge Pressure: 135 barg
    - Train arrangements:
        - 1 x 100% mass flow rate
        - 2 x 50% mass flow rate
- Dehydration
    - Inlet Pressure: 40 - 60 barg
    - Inlet Temperature: 35-40 °C
    - Feed composition: Saturated CO_2 with approximately 0.3 mol% H_2O (~3000 ppm)
    - Target product moisture content: 50 ppmv.
        - A moisture content of less than 1 ppmv has been considered in the preliminary design of the adsorption package with molecular sieve.
    - Train arrangement:
        - 2 x 50% mass flow rate
- Availability of cooling water temperature on site: 7.3 - 27.5°C (17.3°C average)

5.3. Process Simulation

5.3.1. General Simulation Assumptions

The following general assumptions were used to define the CO_2 compression and dehydration HYSYS simulation models.

- General:
    - Property package: Peng-Robinson (EOS). During FEED verify equation of state used by suppliers and by FEED/EPC contractor (refer to HAZID/ENVID). The actual critical point for Drax CO_2 will be established once impurities are verified by the capture plant technology provider.
    - Quality of available cooling water: Brackish water
    - Condensate separated from the Knock Out (KO) drums is circulated to the previous KO drum and is discharged from the first

- Pressure
  - KO drums ΔP: 0.1 bar
  - Compressor inter-coolers:
    - Shell side ΔP: 0.4 bar
    - Tube side ΔP: 0.2 bar
  - Dehydration unit ΔP: 0.9 bar (assumed value for the compression models)
- Temperature
  - Cooling water inlet temperature: 27.5°C
  - Cooling water outlet temperature limited to 40°C
  - Low pressure steam temperature at ~150°C and 4 barg
  - Compression discharge temperature from aftercooler: 45°C
- Efficiency:
  - Polytropic efficiency of compressors has been adjusted to meet vendors' specifications of their units
  - Adiabatic pump efficiency: 75%

5.3.2. Heat exchanger design assumptions

Aspen's Exchanger Design and Rating (EDR) was used to design and size the heat exchangers that were not included in the vendors' quotes. These were:

- Compression:
  - Aftercoolers
- Dehydration:
  - Regeneration gas steam heaters
  - Regeneration gas coolers

The following assumptions were used for the EDR models:

- Heat exchanger type: Shell and tube
- Location of hot fluid: Shell side
- Location of cold fluid: Tube side
- Fouling:
  - Steam: 00009 m^2K/W
  - Carbon dioxide: 0.00018 m^2K/W
  - Brackish water: 0.00018 m^2K/W
- Geometry:
  - Front head type: B – Bonnet bolted or integral with tubesheet
  - Shell type: E – one pass shell
  - Rear head type: M – bonnet
  - Position: horizontal
  - Tube pattern: triangular
- Cylinder material: Stainless Steel 316L
- Tube material: Stainless Steel 316L[8]
- Design specification:
  - TEMA class: C – general service
  - Material standard: ASME

[8] Tube material to be reviewed during pre-FEED study. Depending on the cooling water quality analysis, the tube may need to be upgraded to a higher material, according to Atkins's past experience

5.4. CO_2 Compression Unit

Following the recommendations from stage 2A presented in Section 4.3 and after discussions with Drax, four cases were taken forward for full analysis. During stage 1 meeting with Drax, it was agreed that due to vendor resource constraints, each vendor previously contacted would focus only on one case.

A summary of the cases is presented in Table 5-3.

Table 5-3 - Summary of the four cases examined for the CO_2 compression unit

	Case 1	Case 2	Case 3	Case 4
Data source	Vendor / HYSYS	Vendor / HYSYS	Vendor / HYSYS	Vendor / HYSYS
Compressor type	Integrally geared	Integrally geared	Integrally geared	Integrally geared
Train Configuration	2 x 50%	2 x 50%	2 x 50%	1 x 100%
Suction Pressure	0.6 barg	2 barg	3 barg	0.6 barg
Discharge Conditions	135 barg / 45°C[9]	135 barg / 45°C	135 barg / 45°C	135 barg / 45°C
Intercoolers (per train)	4	4	3	4
Aftercoolers (per train)	1	1	1	1
Footprint (per train)	16.5 x 11.5 x 9 m	12.5 X 10.5 m	13 x 11 m	15.5 x 14 x 8.5 m
Absorbed Power (total)	40,760 kW	37,200 kW	32,620 kW	40,690 kW
Water Req (total)	5,554 m^3/h	5,101 m^3/h	5,028 m^3/h	5,545 m^3/h

5.4.1. PFDs and H&MB

This section presents the Process Flow Diagrams (PFDs) and associated Heat and Mass balances (H&MB) for the four CO_2 compression cases. All cases were modelled in Aspen HYSYS according to information received from vendors. The assumptions used in the models are presented in Section 5.3.1 and 5.3.2.

[9] A case reducing the CO_2 discharge temperature to 36°C was also assessed. For more information, please refer to Section 7.3

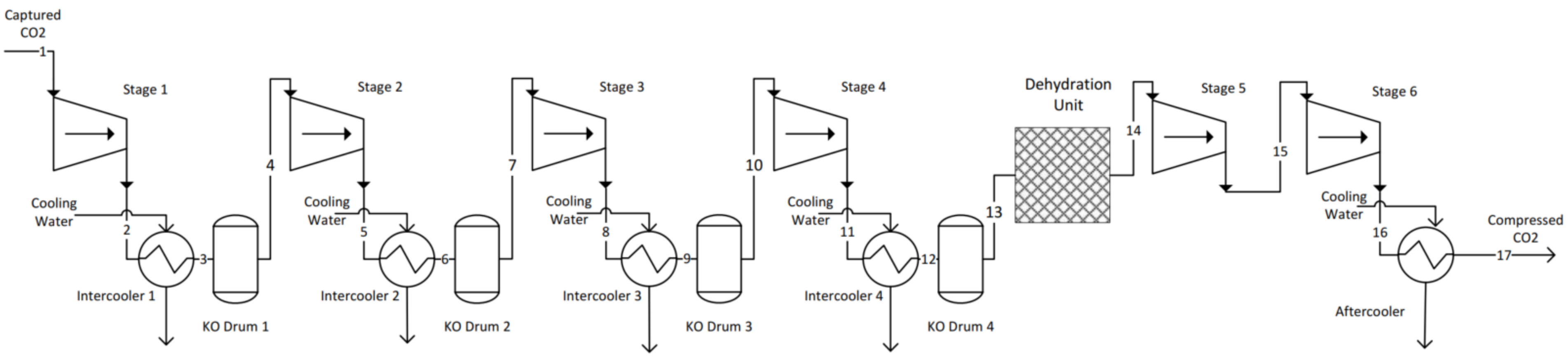


Figure 5-1 - Case 1 - 2 x 50% (0.6 barg) PFD

Table 5-4 - Case 1 - 2 x 50% (0.6 barg) stream conditions

Stream	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	17b[10]
Temperature (°C)	30	124.4	35.5	35.4	111.5	35.5	35.4	109.6	35.5	35.4	110.2	35.5	35.4	34.5	80.3	126.5	45	36
Pressure (barg)	0.6	3.56	3.2	3.16	9.139	8.739	8.65	21.69	21.29	21.19	50.05	49.65	49.55	49.05	82.73	135	134.6	134.6
Mass Flow rate (t/h)	228.4	228.4	228.4	226.1	226.1	226.1	225.4	225.4	225.4	225.1	225.1	225.1	225.0	224.8	224.8	224.8	224.8	224.8
Density (kg/m^3)	2.8	6.1	7.3	7.3	14.2	17.6	17.4	33.1	43.3	43.0	80.1	123.1	122.8	121.8	173.5	236.0	660.3	751.1
% CO_2 (% mol)	96.20%	96.20%	96.20%	98.56%	98.56%	98.56%	99.32%	99.32%	99.32%	99.64%	99.64%	99.64%	99.70%	100.00%	100.00%	100.00%	100.00%	100.00%
% H_2O (% mol)	3.80 %	3.80 %	3.80 %	1.44 %	1.44 %	1.44 %	0.68 %	0.68 %	0.68 %	0.36 %	0.36 %	0.36 %	0.30 %	0%	0%	0%	0%	0%

[10] 17b represents the discharge conditions when using an upgraded aftercooler as discussed in Section 7.3

Figure 5-2 - Case 2 - 2 x 50% (2 barg) PFD

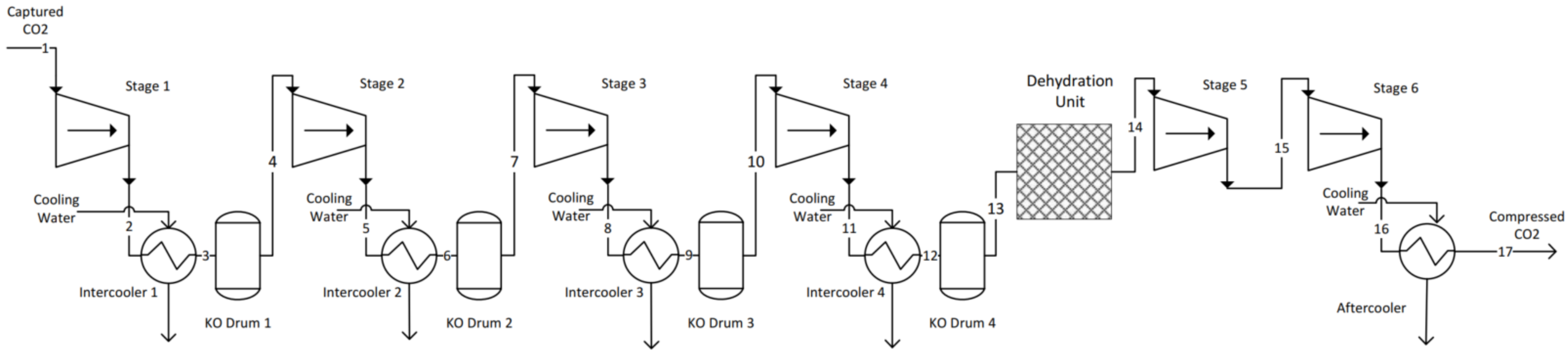


Figure 5-2 - Case 2 - 2 x 50% (2 barg) PFD

Table 5-5 - Case 2 - 2 x 50% (2 barg) stream conditions

Stream	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Temperature (°C)	30	136	37.5	37.37	119	37.5	37.4	106.8	37.5	37.4	79.49	40.1	40	39	80.8	117	45
Pressure (barg)	2	8	7.6	7.5	19	18.6	18.5	39	38.6	38.5	60.5	60.1	60	59.1	94	135	134.6
Mass Flow rate (t/h)	228.4	228.4	228.4	225.5	225.5	225.5	225.1	225.1	225.1	225	225	225	225	224.7	224.7	224.7	224.7
Density (kg/m^3)	5.2	11.8	15.3	15.1	28.1	37.1	36.8	61.7	85.8	85.5	116.0	158.6	158.3	155.7	206.5	253.7	660.3
% CO_2 (% mol)	96.20 %	96.20 %	96.20 %	99.16 %	99.16 %	99.16 %	99.57 %	99.57 %	99.57 %	99.70 %	99.70 %	99.70 %	99.70 %	100.00%	100.00%	100.00%	100.00%
% H_2O (% mol)	3.80 %	3.80 %	3.80 %	0.84 %	0.84 %	0.84 %	0.43 %	0.43 %	0.43 %	0.30 %	0.30 %	0.30 %	0.30 %	0.00%	0.00%	0.00%	0.00%

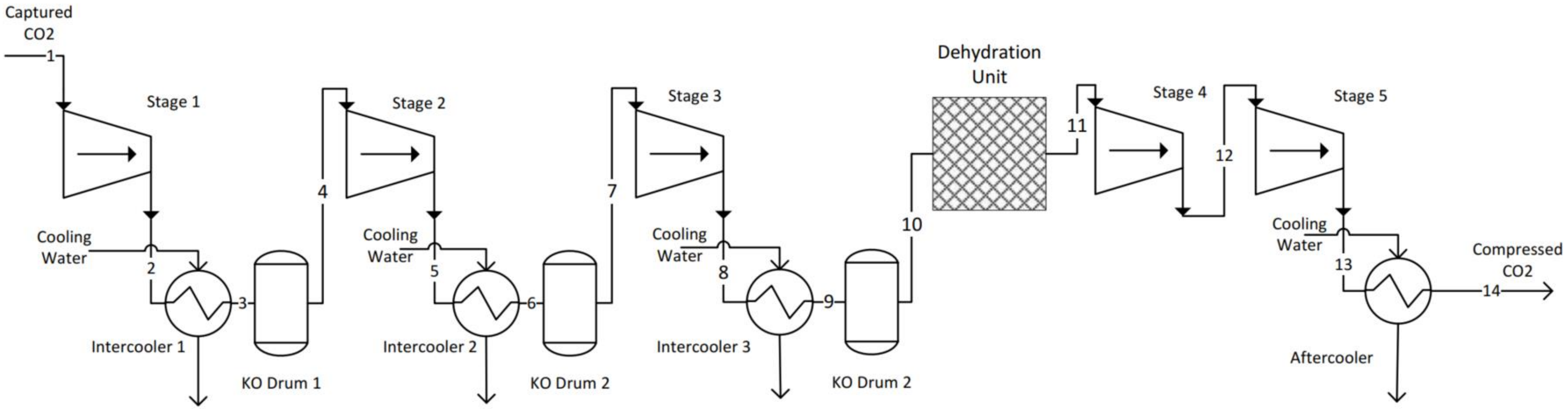


Figure 5-3 - Case 3 - 2 x 50% (3 barg) PFD

Table 5-6 - Case 3 - 2 x 50% (3 barg) stream conditions

Stream	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Temperature (°C)	30	139.2	37.5	37.39	113	37.5	37.4	97	37.5	37.4	37	78.4	126.8	45
Pressure (barg)	3	12.1	11.7	11.6	27.53	27.13	27.25	52.31	51.91	51.81	51.82	82	135	134.6
Mass Flow rate (t/h)	228.4	228.4	228.4	225.3	225.3	225.3	225.0	225.0	225.0	225.0	224.7	224.7	224.7	224.7
Density (kg/m^3)	7.2	17.1	23.1	22.9	41.8	56.1	55.9	89.1	129.1	128.8	129.1	174.0	235.6	660.3
% CO_2 (% mol)	96.20 %	98.88 %	98.88 %	99.40 %	99.40 %	99.40 %	99.65 %	99.65 %	99.65 %	99.70 %	100.00 %	100.00 %	100.00 %	100.00 %
% H_2O (% mol)	3.80%	1.12%	1.12%	0.60%	0.60%	0.60%	0.35%	0.35%	0.35%	0.30%	0.00%	0.00%	0.00%	0.00%

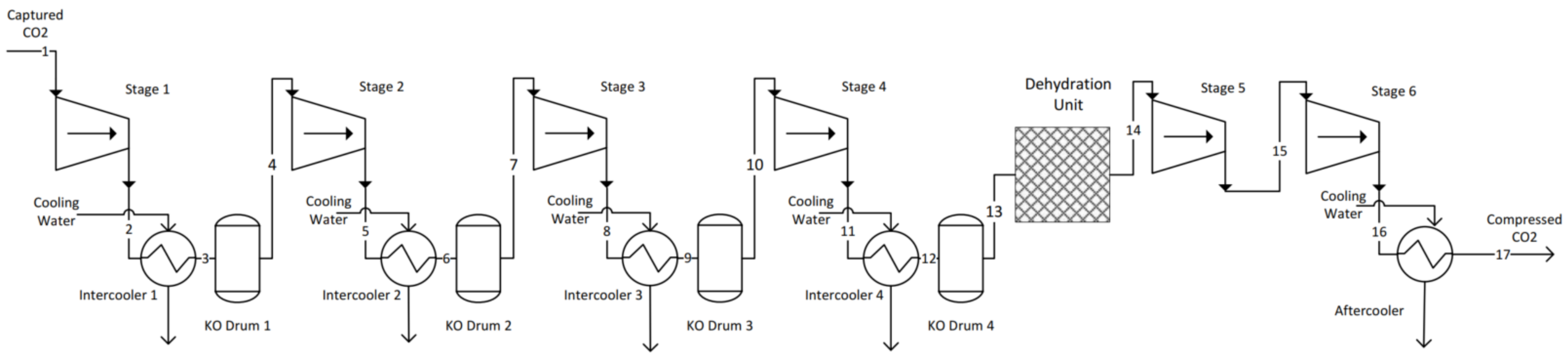


Figure 5-4 - Case 4 - 1 x 100% (0.6 barg) PFD

Table 5-7 - Case 4 - 1 x 100%(0.6 barg) stream conditions

Stream	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Temperature (°C)	30	124.4	35.5	35.4	111.5	35.5	35.4	109.6	35.5	35.4	110.2	35.5	35.4	34.5	80.3	126.5	45
Pressure (barg)	0.6	3.56	3.2	3.16	9.139	8.739	8.65	21.69	21.29	21.19	50.05	49.65	49.55	49.05	82.73	135	134.6
Mass Flow rate (t/h)	456.0	456.0	456.0	451.4	451.4	451.4	450.0	450.0	450.0	449.4	449.4	449.4	449.2	448.7	448.7	448.7	448.7
Density (kg/m^3)	2.8	6.1	7.3	7.3	14.2	17.6	17.4	33.1	43.3	43.0	80.1	123.1	122.8	121.8	173.5	236.0	660.3
% CO_2 (% mol)	96.20 %	96.20 %	96.20 %	98.56 %	98.56 %	98.56 %	99.32 %	99.32 %	99.32 %	99.64 %	99.64 %	99.64 %	99.70 %	100.00%	100.00%	100.00%	100.00%
% H_2O (% mol)	3.80 %	3.80 %	3.80 %	1.44 %	1.44 %	1.44 %	0.68 %	0.68 %	0.68 %	0.36 %	0.36 %	0.36 %	0.30 %	0%	0%	0%	0%

5.4.2. Process Description

Integrally geared compressor technology is based around a central (integral) gear box in which a main bull gear drives a number of separate pinions, forming a compact skid with small footprint. These pinions supply power to compression stages that are paired sequentially into stage groups of two. All shafts are mounted in oil-lubricated hydrodynamic bearings. The inlet flow of the compressor is typically controlled by Inlet Guide Vanes (IGVs) positioned in front of each stage. IGVs provide stable compressor operation over a wide range of conditions at a constant discharge pressure. IGVs regulate inlet flow to ensure accurate process control and give a significant efficiency increase.

As discussed previously, a typical integrally-geared centrifugal compression process is split into several stages, the number of which depends mainly on the suction pressure of the CO_2 inlet stream. For the low suction pressure cases (0.6 – 2 barg), six compression stages are used, whereas five stages are required for the higher suction pressure case (3 barg). Each compression stage presents a pressure ratio of 1.7-3.2 between outlet and inlet and the polytropic efficiency of each stage is 80-85%. These are multi-shaft arrangement with different speeds.

The CO_2 capture system will recover 456,000 t/h of 96.2% (mol.) CO_2 from boiler flue gases. This CO_2 stream is first compressed to 50-60 barg using 3 or 4 compression stages, depending on the suction pressure as discussed above. At that pressure the stream is directed to the dehydration unit, which was considered as a black box for the compression modelling cases. The dehydration unit dries the water content in the product gas to 50 ppmv (or less). After successful separation of H_2O, the CO_2 stream returns to the compression skid for a further 2-stage compression to 135 barg.

All cases utilise intercoolers between the stages up to the dehydration unit. Intercooling is key to maximising compression efficiency since it allows the overall compression process to follow a path closer to an ideal, isothermal process. The architecture of integrally geared machines makes it simple to intercool between stages. Since each stage is mounted in a separate housing and the discharge is collected in a volute for transfer to the next stage, it is simple and inexpensive to incorporate intercooling between stages. However, care must be taken in the design of the inter-stage components to ensure that the performance improvement (power reduction) obtained by intercooling is not nullified by excessive pressure drop through the coolers and piping.

Water condensed in the intercoolers in the wet stages of the compressor, i.e. before the dehydration unit, drains into the KO drums. The condensate is then recycled to the previous KO drum and is eventually rejected from the first KO drum.

Late-stage intercooling (after the dehydration unit) is not added in order to create a tolerance zone above the critical temperature of CO_2. When the CO_2 is above its critical point (73.9 bara at 31 °C) the CO_2 is known as a supercritical fluid. If the temperature drops to below its critical temperature, then the fluid turns into a dense liquid. Hence, by maintaining the CO_2 above its critical point prevents dense liquid from entering the final stage of compression.

The last two compression stages are the dry stages, where the dry CO_2 gas (>99.9% mol.% CO_2) is compressed from the dehydration outlet pressure (40-60 barg) to the battery limit pressure of 135 barg. After the last compression stage (135 barg), the CO_2 stream is at 110-130°C, hence the use of an aftercooler is required to cool down the CO_2 stream prior to entering the pipeline for transport. The temperature of the compressed CO_2 stream at the outlet of the compression plant has been assumed to be 45 °C (to be verified during next stage of design).

5.4.3. Major Equipment List

The major equipment items within the four compression package options are listed in Table 5-8.

Table 5-8 - Major equipment list for each compression case

Equipment	Case 1	Case 2	Case 3	Case 4
Data source	Vendor / HYSYS	Vendor / HYSYS	Vendor / HYSYS	Vendor / HYSYS
Compressor type	IG	IG	IG	IG
Train Configuration	2 X 50%	2 X 50%	2 X 50%	1 X 100%
Equipment Included in the quotes				
Compressor package	2	2	2	1
Interstage coolers	8	8	6	4
Aftercoolers	-	-	2	-
Knock out Drums	8	8	6	4
Lube oil unit	2	2	2	1
Seal System	2	2	2	1
Pipework, instrumentation	1	1	1	1
Interconnecting pipework / manifolds	1	1	1	0
Skid mounting/Base Plate	2	2	2	1
PSVs, Control Valves, Vents & Drains	1	1	1	1
Anti-surge control	4	4	4	2
Electric Motor	2	2	2	1
Unit Control Panel	2	2	2	1
Equipment sized and costs calculated internally				
Aftercoolers	2	2	-	1
HV Switchgear 11kV, breakers & VSD protection system	1	1	1	1
Other equipment required and costs estimated from past projects				
Harmonic filter for frequency converter	1	1	1	1
Discharge silencer wet section	1	1	1	1
Discharge silencer dry section	1	1	1	1

Table 5-9 presents the heat duty of every intercooler and aftercooler for each compression stage, retrieved from Aspen HYSYS simulations. Since all intercoolers were included in the vendors' quotes, no intercooling sizing was required at this stage. The aftercoolers for cases 1, 2 and 4 were not included in the quotes received from the vendors and as such these were sized and costed using Aspen EDR modelling.

Table 5-9 - Heat duty of intercoolers/aftercooler for each compression case

Heat Exchanger	Case 1	Case 2	Case 3	Case 4
Intercooler 1 (kWth)	12,124	12,526	13,042	12,100
Intercooler 2 (kWth)	9,984	10,608	10,096	9,967
Intercooler 3 (kWth)	9,694	9,850	9,518	9,678
Intercooler 4 (kWth)	11,584	7,122	-	11,560
Aftercooler (kWth)	25,480	23,280	25,540	25,430
Total	**68,866**	**63,386**	**58,196**	**68,735**

5.4.4. Operations & Maintenance Philosophy

The Operations and Maintenance (O&M) philosophy is intended to give an overview of the way in which the compression assets will be operated, to describe the operational requirements to be applied to the design, and to document the philosophy for maintenance of the units. At this stage the O&M philosophy is focusing on the following aspects:

- Availability and reliability of compressor units
- Turndown capabilities of the compression units and part load operation philosophy
- Maintenance schedules of the compression units, according to vendors information

5.4.4.1. Availability/Reliability

Table 5-10 shows the average values for availability and reliability, derived from the hours required for typical inspection, maintenance, repairs and overhaul per year, according to one of the vendors. Two other vendors suggested similar availability/reliability figures. A detailed maintenance schedule is presented in Section 5.4.4.3.

Table 5-10 - Availability and Reliability figures of integrally geared machines

Compressor Type	Availability %	Reliability %	Inspection, Maintenance, Repair & Overhaul (hr/year)	Forced Downtime (hr/year)	Mean Time Between Failure (year)
Integrally geared (clean service)	99.7	99.8	24.8	18.8	8.0
Integrally geared (fouling service)	99.0	99.5	90.6	40.6	3.7

5.4.4.2. Turndown

It is understood that compressor's turndown capability is of critical importance to Drax. During stage 1 meeting the feasibility of having a turndown to 33% was discussed and compressors' performance curves were requested from the vendors for each selected case. For the case of integrally geared compressors, inclusion of IGVs were suggested by all vendors. The possibility to install the IGVs is facilitated by the direction of the gas flow at inlet of the impeller (axial), the shape of the casing and the space available that allows the application of this solution on integrally geared machines compared to the conventional in-line type.

Integrally geared compressor units present a turndown capability of 20-30%, depending on the vendor selected. This means that the compressor is able to operate at 70-80% part-load by utilising the existing IGVs installed before each stage. For further turndown, gas recirculation will be required resulting in a less efficient process. The installation of two parallel compressor trains results in higher flexibility, making it possible to achieve operation at the range of 35-50% load by simply switching off one of the trains. However, the turndown to 33%

requested by Drax is probably going to require gas recirculation bleed. Figure 5-5 presents the operating load areas for which recirculation bleed (grey) or IGVs (green) are required.

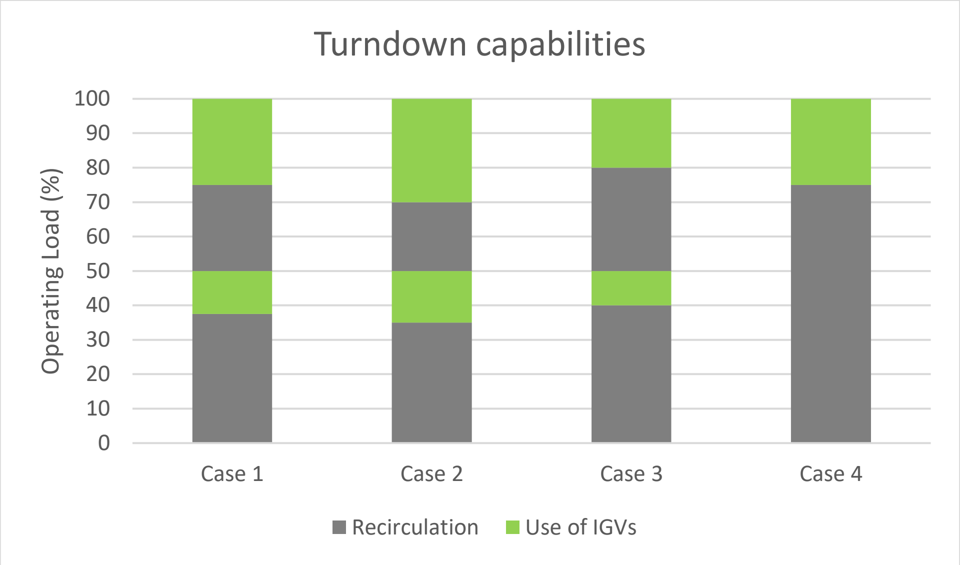


Figure 5-5 - Achievable turndown for each case

Further analysis of the vendors' performance curves showed that the use of IGVs has a marginal effect on the polytropic efficiency of each compression stage for the integrally geared machines. However, the use of recirculation bleed results in significantly increased absorbed power requirements per tonne of CO_2 compressed. Figure 5-6 shows the variance of absorbed power per tonne of compressed CO_2 versus the operating load for the 2 x 50% trains arrangement and 0.6 barg suction pressure (case 1). Similarly to Figure 5-5, recirculation bleed is presented in grey, while the range where IGVs are effective is presented in green. It is notable that there is a significant increase in absorbed power per tonne of compressed CO_2 between 30%-37.5% and 50%-77.5% for which recirculation is required, while for the case of IGVs the efficiency remains almost constant. Specifically, an efficiency loss of ~4% was calculated between the minimum and maximum setting of the IGV.

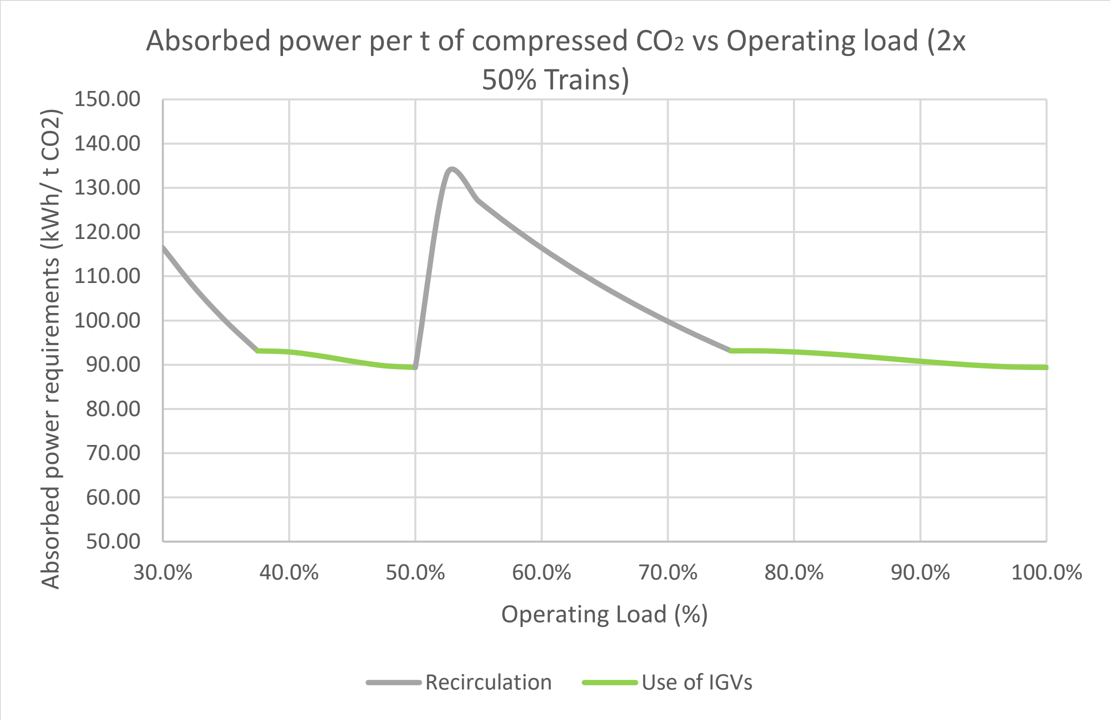


Figure 5-6 - Absorbed power requirements per tonne of CO_2 compressed for the 2 x 50% case at 0.6 barg suction pressure (from vendor)

Similarly, Figure 5-7 shows the variance of absorbed power per tonne of compressed CO_2 versus the operating load for the 1 x 100% train arrangement and 0.6 barg suction pressure (case 4). Since there is only one train present at this case, it is not possible to achieve operating loads lower than 77.5% by using IGVs. As such, the absorbed power per tonne of compressed CO_2 for a 30%-50% operating load is significantly higher compared to the 2 x 50% train arrangement due to the amount of gas that will require recirculation. Once again, part load operation by using IGVs did not result in significant efficiency drop and as such, the power requirements per tonne of compressed CO_2 remains almost constant.

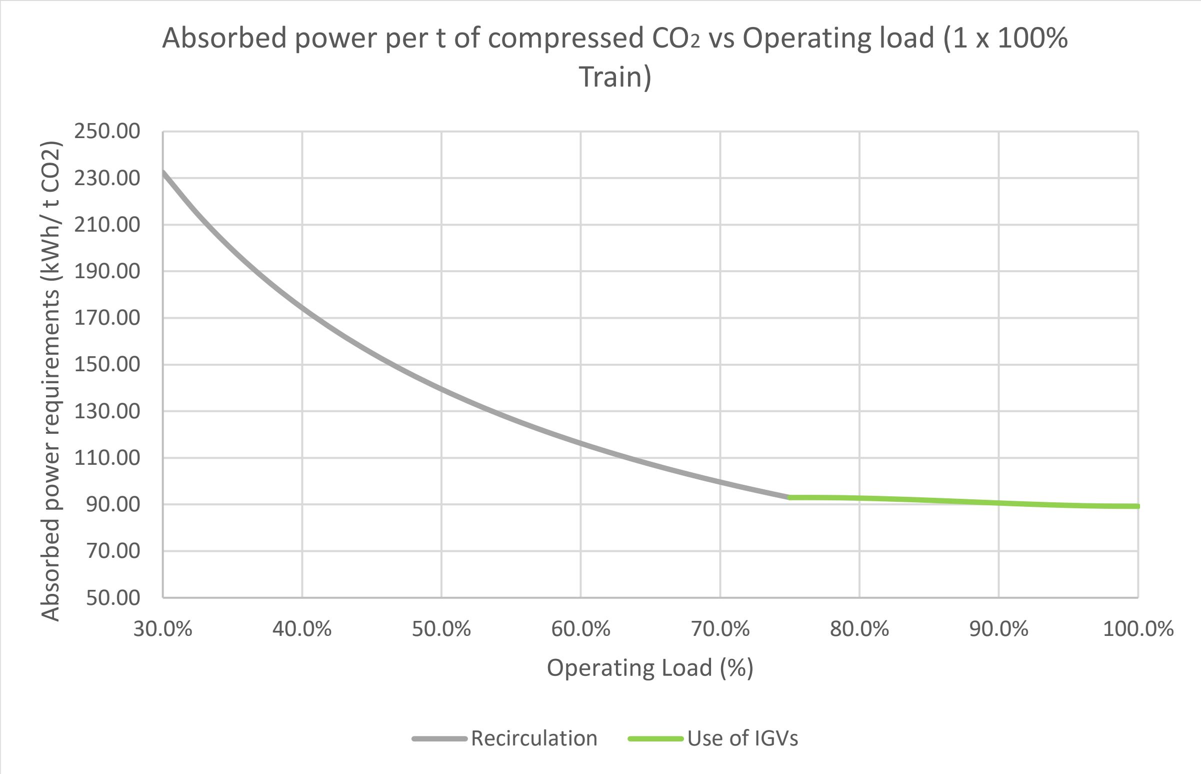


Figure 5-7 - Absorbed power requirements per tonne of CO_2 compressed for the 1 x 100% case at 0.6 barg suction pressure (from vendor)

One interesting point derived from Figure 5-6 and Figure 5-7 is that for the required turndown to 33%, the absorbed power requirement per tonne of compressed CO_2 is significantly higher in the case of 1 x 100%, compared to the 2 x 50% arrangement. This trend continues between the 30 and 50% operating load. This difference in power requirements stems from the fact that in the 2 x 50% train configuration, one machine can be simply switched off for low operating loads, as seen in Figure 5-5.

This significant difference in power requirements for those two train arrangements results in significantly increased power costs and overall OPEX when using one train. Annual power costs for various turndown values for both train arrangements can be seen in Figure 5-8. All costs are taken as a ratio of the 52-72% operating range as these have very similar operating costs regardless of the arrangement type. As expected, in the range of 30-50% the power costs are double when using 1 x 100% train, compared to the 2 x 50% configuration. Above 50% operating load, there is no significant difference, since all machines are switched on and require similar levels of gas recirculation for efficient operation.

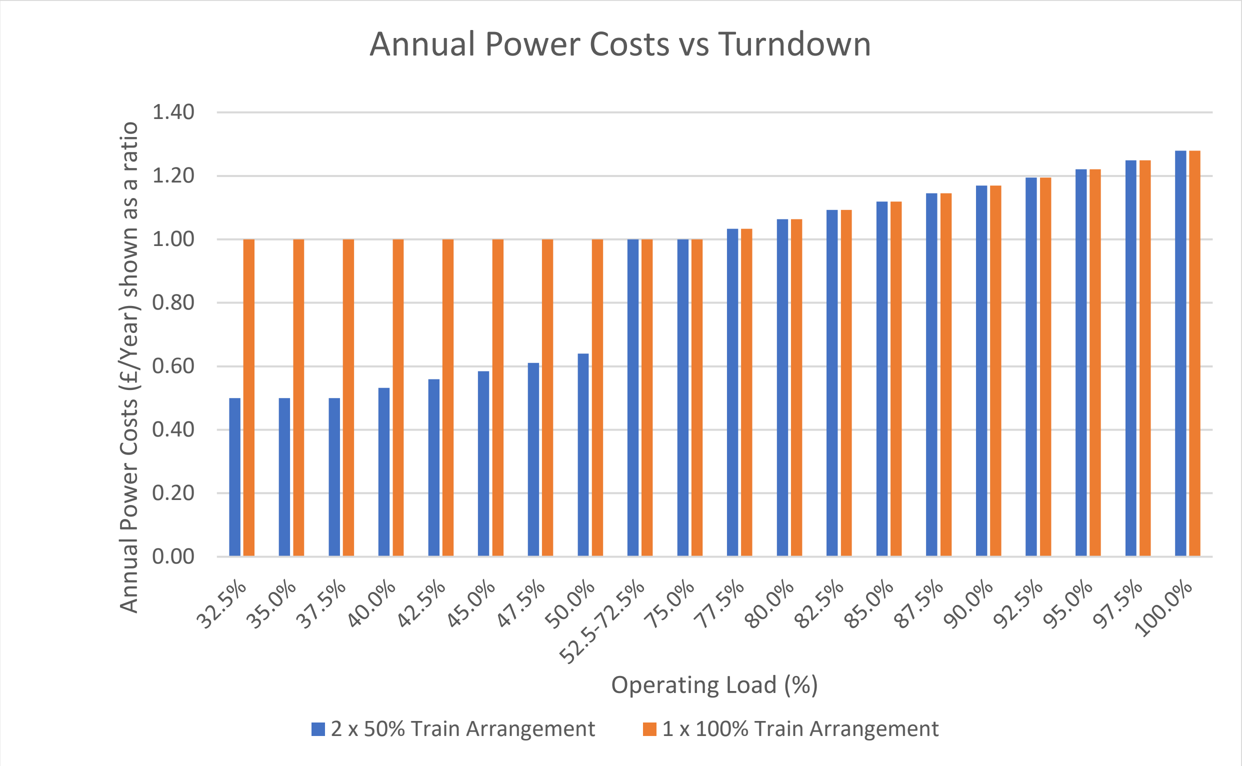


Figure 5-8 – Comparison of annual power costs vs turndown for the 2 x 50% and 1 x 100% train arrangements

5.4.4.3. Maintenance philosophy

Maintenance strategies will make a substantial contribution to the economic operation of the compression units. It is expected that the core O&M staff will handle all routine maintenance, requiring only specialised or contract maintenance personnel for the non-routine and any major maintenance activity (e.g. Turnarounds, preventive maintenance etc.).

Typical maintenance concept includes the following schedule:

- Level 1 routine maintenance – (on-line, no dismantling) – Minor inspection (once per year):
    - Functional test according to manual.
    - Checking and comparing of operational data, performance, vibration, etc.
    - Oil analysis
- Level 2 routine maintenance (Minor overhaul, compressor stopped) – Major inspection (Year 6):
    - Alignment check
    - Bearings inspection
    - Shaft seal inspection
    - Visual Gear tooth check
    - Coupling inspection
    - IGV inspection
    - Oil sealing rings inspection
- Level 3 preventive maintenance (Disassembly of machine and cleaning, inspection of all components)– Major inspection (Year 10):
    - Change all bearings out
    - Change all seals out

- Change of Gear Set
- Cleaning of parts
- Change wear parts IGV
- Assemble new parts
- Alignment

The typical maintenance schedule is as follows:

- Minor inspection is carried out after 2.5 years of operation
- Major inspection is carried out after 5 years of operation

The maintenance strategy may evolve or change during the operating life of the compression units due to possible influences from regulatory requirements, technology, age of asset, changes in operating condition, economic considerations, resource availability and capacity.

5.4.5. Utility Summary

As discussed previously, a typical integrally-geared centrifugal compression process is split into several stages, each of which has a polytropic efficiency of ~80-85% depending on the vendors' models. Each stage presents a pressure ratio of 1.7-3.2 between outlet and inlet streams. Compressors require electric power to operate, which is assumed to be provided by an electric motor driver. Other options include steam turbine or gas turbine drives, as will be discussed later in this report. Aspen HYSYS simulations assumed the use of an electric motor driver. Table 5-11 presents the duty (kWe) of each compression stage, taken from the Aspen HYSYS models, matching the overall energy requirements provided by the vendors for each case.

Table 5-11 - Power requirements of each compression stage per case

Compression Stage	Case 1	Case 2	Case 3	Case 4
Stage 1 (kWe)	10,730	11,924	12,208	10,710
Stage 2 (kWe)	8,324	8,756	7,782	8,319
Stage 3 (kWe)	7,693	6,850	5,404	7,651
Stage 4 (kWe)	6,948	3,590	3,144	6,929
Stage 5 (kWe)	3,326	3,154	4,082	3,336
Stage 6 (kWe)	3,739	2,926	-	3,745
Total	40,760	37,200	32,620	40,690

The absorbed power requirements for the four compression cases are summarised in Figure 5-9. As expected, operating the stripper at higher pressures results in lower absorbed power required during compression as the total pressure ratio is reduced. A 10% reduction in absorbed power is evident when increasing the suction pressure from 0.6 barg to 2 barg. A further 10% reduction in power requirements is observed for the 3 barg suction pressure (case 3). As will be discussed in sections 6.13 and 7.2, this significant reduction in absorbed power results in lower OPEX.

In addition, it is notable that there is marginal difference between the 2 x 50% and the 1 x 100% train arrangements when using 0.6 barg suction pressure.

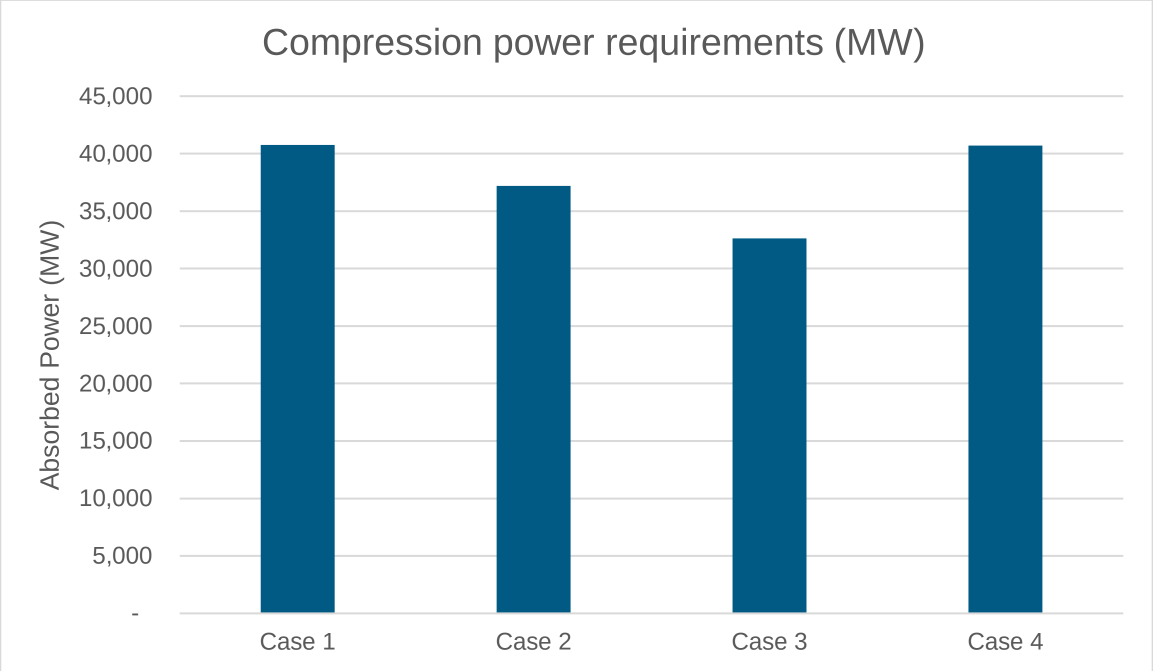


Figure 5-9 - Comparison of power requirements for the four compression cases

The CO_2 compressor requires cooling water for the intercoolers, aftercooler, lube oil coolers and other auxiliary equipment. The cooling water requirements for the four compression cases are summarised in Figure 5-10. A similar trend to the absorbed power is observed for the cooling water as well, where the lowest requirements are presented for the 3 barg suction pressure case. However, the difference between the three cases is marginal and does not translate in significant OPEX savings as it will be discussed in Section 6.12.

No significant difference between the 2 x 50% and the 1 x 100% train arrangements when using 0.6 barg suction pressure was observed.

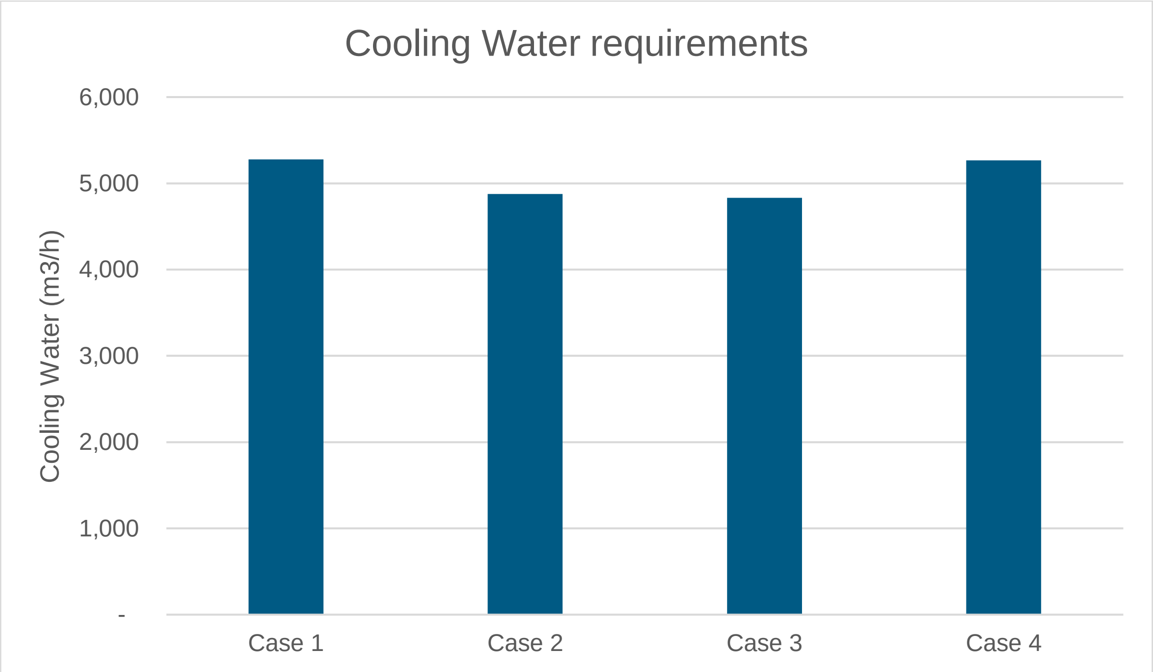


Figure 5-10 - Comparison of cooling water requirements for the four compression cases

In addition to the power and cooling water requirements, lube oil is also essential for the compression stage. The lube oil system supplies oil to the compressor and driver bearings as well as to the gears and couplings. The lube oil is drawn from the reservoir by the oil pumps and is fed to the bearings under pressure via coolers and filters. Upon leaving the bearings, the oil drains back to the reservoir.

The reservoir is designed to permit circulation of its entire fluid volume between 8 - 12 times per hour. The first oil fill required is approximately 8-10m^3, depending on the vendor and the compressor model. In essence, there is no significant oil consumption, the compressor is expected to use the same oil until the first major maintenance inspection (4-5 years). However, regular checks (during annual maintenance) for any top-up requirements are advisable.

The lube oil system is roughly designed for a flow of 630 l/min.

5.4.6. Plot size – Layout

Plant layouts for both 2 x 50% and 1 x 100% train arrangements have been developed for the scheme in order to calculate the overall plot size required on Drax site. The compression and dehydration units have been drawn in accordance with general arrangement information provided by vendors. For the 2 x 50% train arrangement, only one case is presented which corresponds to the largest footprint (case 1, 0.6 barg suction pressure). Similarly, the dehydration box depicts the largest of the three options considered in this report, namely adsorption with molecular sieves. For detailed information on the dehydration layout please refer to Section 5.5.6.

Figure 5-11 shows the plant layout of the 2 x 50% train arrangement. The plot size for this case is approximately 2,700 m^2. It is estimated that another 1500m^2 would be required for construction facilities and construction laydown. Construction would not occur across the whole of the site simultaneously which would allow some areas to be used as temporary lay down during construction. Therefore, an allowance of 800 m^2 is advised by Atkins for Construction Welfare, Offices and Laydown outside of the plant footprint. As such, the total space allowance should be ~3,500 m^2.

As presented in Table 5-3 earlier, the largest footprint for the 2 x 50% compression skid was reported for case 1 (0.6 barg), namely 16.5 x 11.5. This area encloses the six compression stages, balance of plant, electric motor and lube oil system. There is a 10m allowance at the west side of the compressor skids to facilitate bundle removal from the shell and tube heat exchangers. The dehydration unit is located in close proximity to the compression skids. Pipe runs are located between the compressor and dehydration units. There is a 360 m^2 space allowance at the south end of the area that serves as the maintenance / laydown area. The control room is located on the north east side of the area and occupies ~60m^2. HV/MV switchboards are located on the south east side of the area, occupying approximately 67.5 m^2.

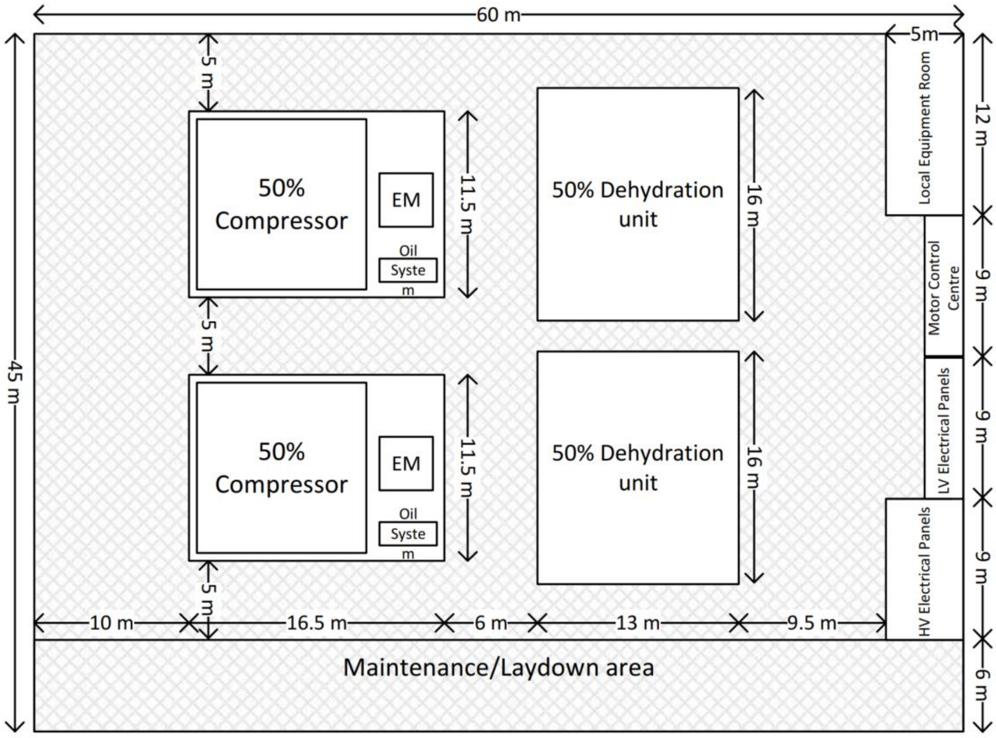


Figure 5-11 - Compression and dehydration plant layout for the 2 x 50% case

Figure 5-12 shows the plant layout for the 1 x 100% train arrangement. The plot size for this case is approximately 2,160 m^2. Assuming similar construction requirements as per the 2 x 50% case, the total space allowance on Drax site should be ~ 3,000 m^2.

Similar space allowances for maintenance requirements and control rooms / electrical panels as per the 2 x 50% case were used.

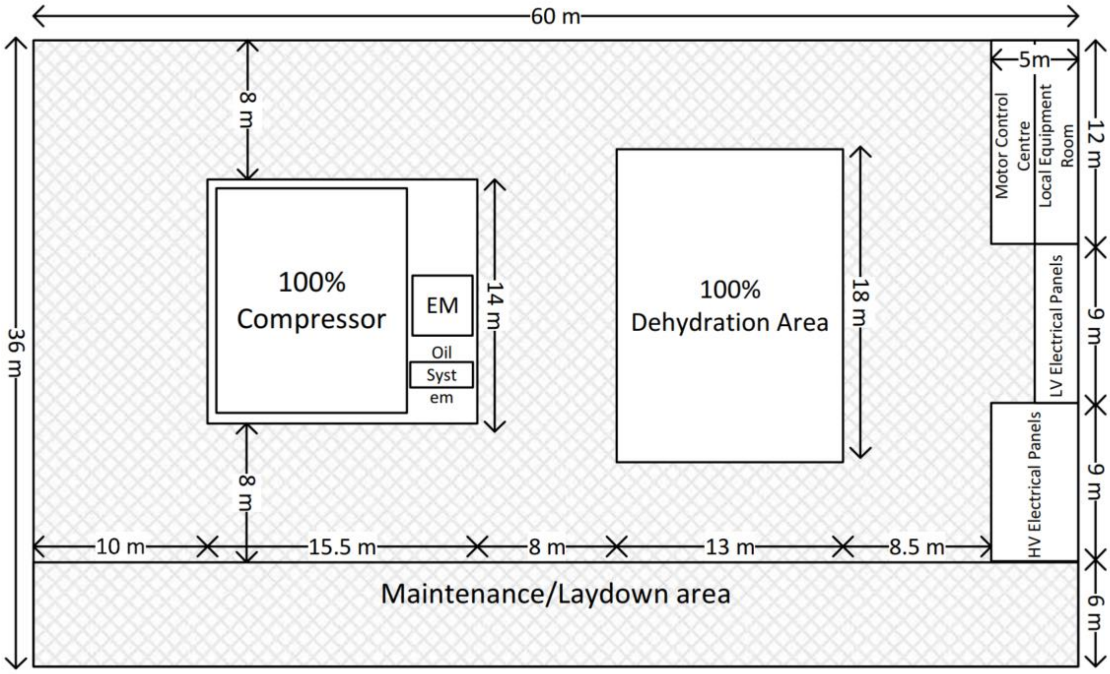


Figure 5-12 - Compression and dehydration plant layout for the 1 x 100% case

The dehydration unit and final compression stages hold CO_2 at pressure. This is a hazard which needs to be considered for layout. Atkins advise that a safety separation distance of at least 120m is required to nearest manned area / building: and this distance is to be confirmed at a later project stage (FEED) by dispersion modelling.

5.5. CO_2 Dehydration Unit

The following dehydration technology options were selected to be carried forward for Stage 2 concept design development and cost estimation:

1. 2 x 50% Silica Gel adsorption dehydration.
2. 2 x 50% Molecular sieve adsorption dehydration (agreed after the stage 1 review).
3. 2 x 50% TEG absorption dehydration.

2 x 50% train arrangement has been assumed as the base case to maintain the overall plant flexibility with both CO_2 capture plant and compression units likely to be split into 2 x 50% trains.

A summary of the three options is presented in Table 5-12.

Table 5-12 - Summary of the CO_2 dehydration technology options

	Adsorption – Silica gel	Adsorption – Molecular sieve	Absorption - TEG
Data source	Vendor / HYSYS	Vendor / HYSYS	Vendor
Train Configuration	2 x 50%	2 x 50%	2 x 50%
Operating temperature / °C	40	40	40
Operating pressure / barg	60	60	45
Regeneration temperature / °C	230	290	204
Regeneration pressure / barg	~60	~60	0.3
Heating duty (per train) / kW	1,484	3,190	425
Cooling duty (per train) / kW	1,815	3,125	0 (fully heat integrated)
Footprint (per train) / m	10 x 16	13 x 16	9.5 x 12.5

5.5.1. PFDs and H&MB

The following section shows the Process Flow Diagrams of the three technology options. For clarity, the adsorption processes have been presented in two different diagrams, one showing the heating phase of regeneration cycle and another showing the cooling phase of regeneration cycle.

5.5.1.1. Adsorption with Silica Gel

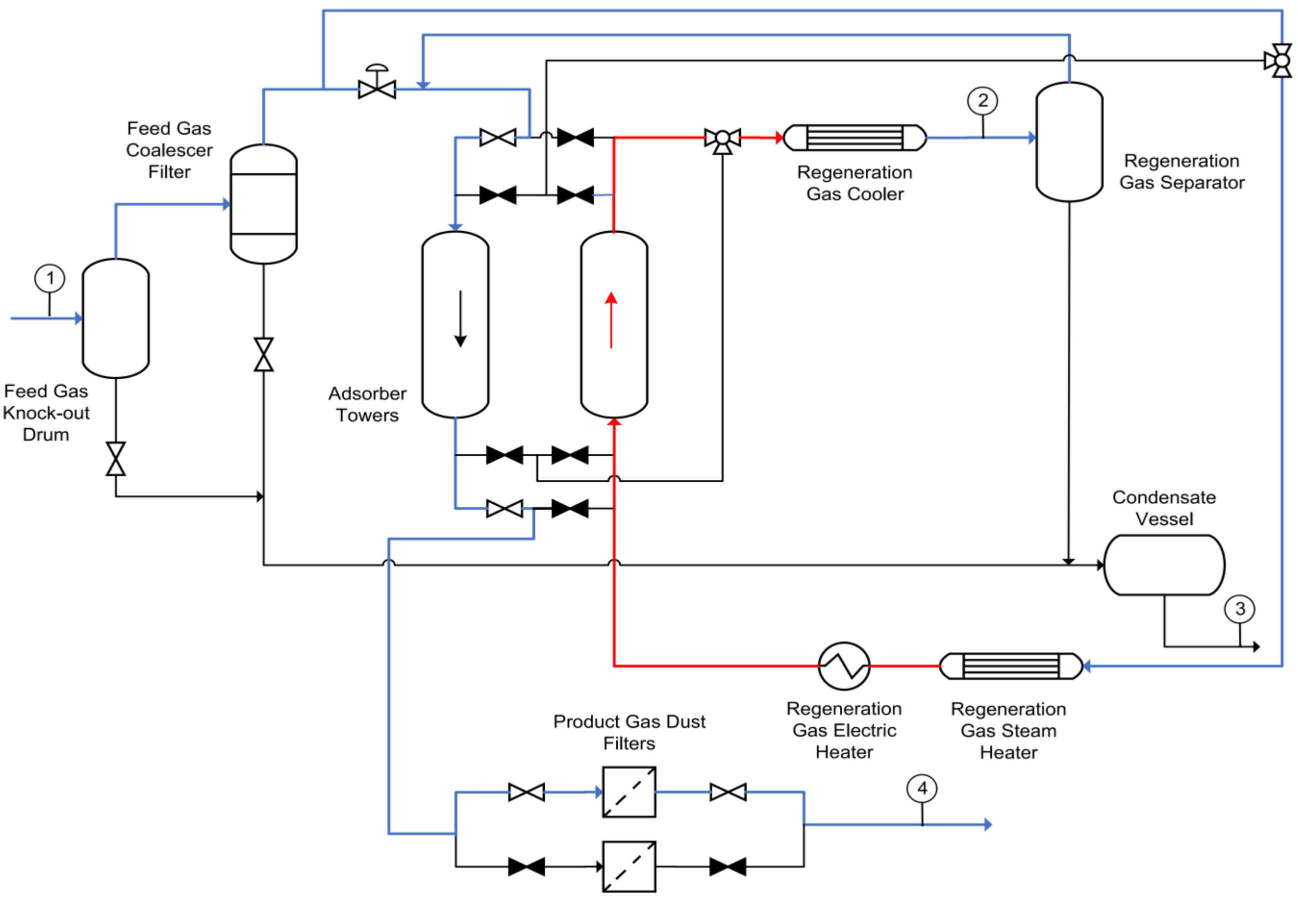


Figure 5-13 - PFD: Adsorption with Silica Gel, Wet Gas Regeneration, Heating Cycle

For adsorption process with silica gel the key stream data are given in Table 5-13 and Table 5-14.

Table 5-13 - Key stream data: Adsorption with Silica Gel, Heating Cycle

Stream	1	2	3	4
Fluid	Wet CO_2 gas	Regeneration gas, average	Condensate	Dry CO_2 gas
Composition (mol%):				
CO_2	99.67	93.62	1.70	99.9950
H_2O	0.33	6.38	98.30	<0.0050
Temperature (°C)	40	40	40	40
Pressure (barg)	60	59	59	57
Mass flow (kg/hr)	228,333	22,360	322	228,011
Density (kg/m³)	158	65	1,004	145

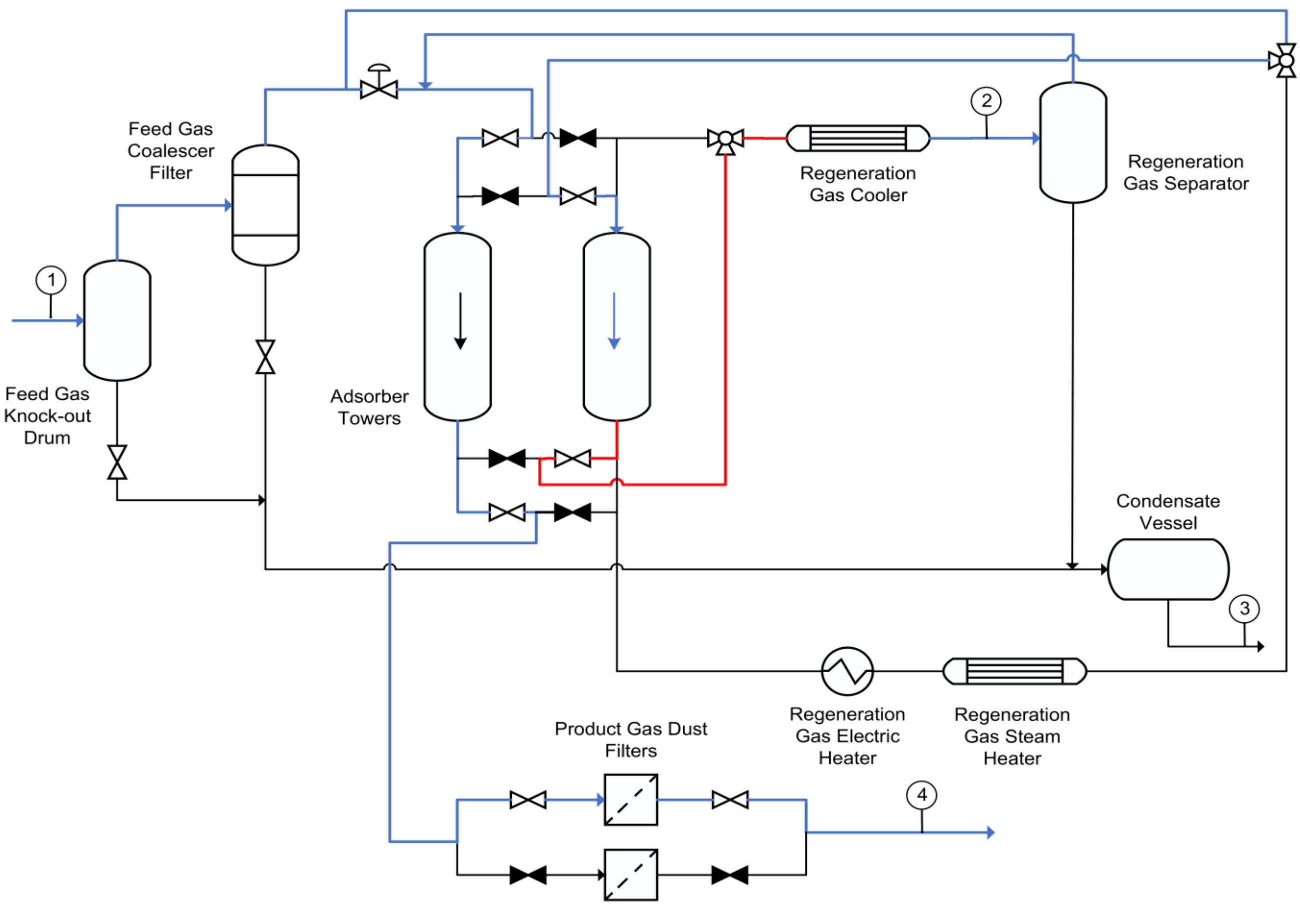


Figure 5-14 - PFD: Adsorption with Silica Gel, Wet Gas Regeneration, Cooling Cycle

The cooling cycle is to ensure the regenerated bed can be safely brought back into service. The regeneration gas composition exiting the dryer is expected to be practically the same as that entering the dryer i.e. wet CO_2. The amount of condensate in the stream is assumed to be negligible as the moisture is removed during the heating phase of regeneration. The minimal flowrate of water is expected from the knock out drum at this stage.

Table 5-14 - Key stream data: Adsorption with Silica Gel, Cooling Cycle

Stream	1	2	3	4
Fluid	Wet CO_2 gas	Regeneration gas, Wet CO_2 gas	Condensate	Dry CO_2 gas
Composition (mol%):				
CO_2	99.67	99.67	1.70	99.9950
H_2O	0.33	0.33	98.30	<0.0050
Temperature (°C)	40	40	40	40
Pressure (barg)	60	~59	59	57
Mass flow (kg/hr)	228,333	23,190	negligible	228,333
Density (kg/m³)	158	154	1,004	145

5.5.1.2. Adsorption with Molecular Sieve

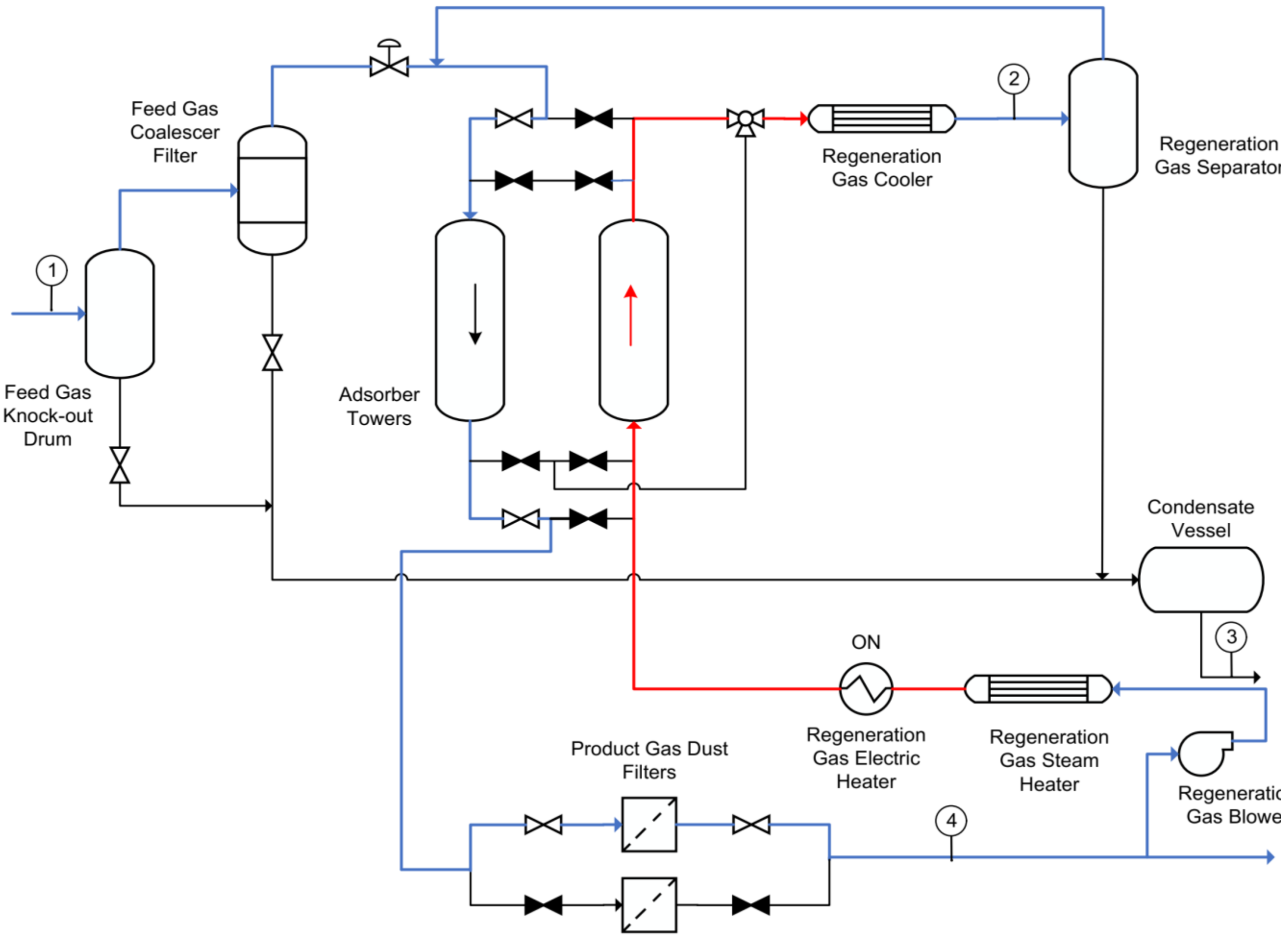


Figure 5-15 - PFD: Adsorption with Molecular Sieve, Dry Gas Regeneration, Heating Cycle

For adsorption process with molecular sieve the key stream data are given in Table 5-15 and Table 5-16.

Table 5-15 - Key stream data: Adsorption with Molecular Sieve, Heating Cycle

Stream	1	2	3	4
Fluid	Wet CO_2 gas	Regeneration gas, dry CO_2 gas	Condensate[11]	Dry CO_2 gas
Composition (mol%):				
CO_2	99.67	99.9999	1.70	99.9999
H_2O	0.33	<0.0001	98.30	<0.0001
Temperature (°C)	40	40	40	40
Pressure (barg)	60	60	60	~58
Mass flow (kg/hr)	228,333	39,000	322	228,011
Density (kg/m³)	158	158	1,004	149

[11] Assuming the condensate stream composition and flowrate is similar to adsorption with silica gel.

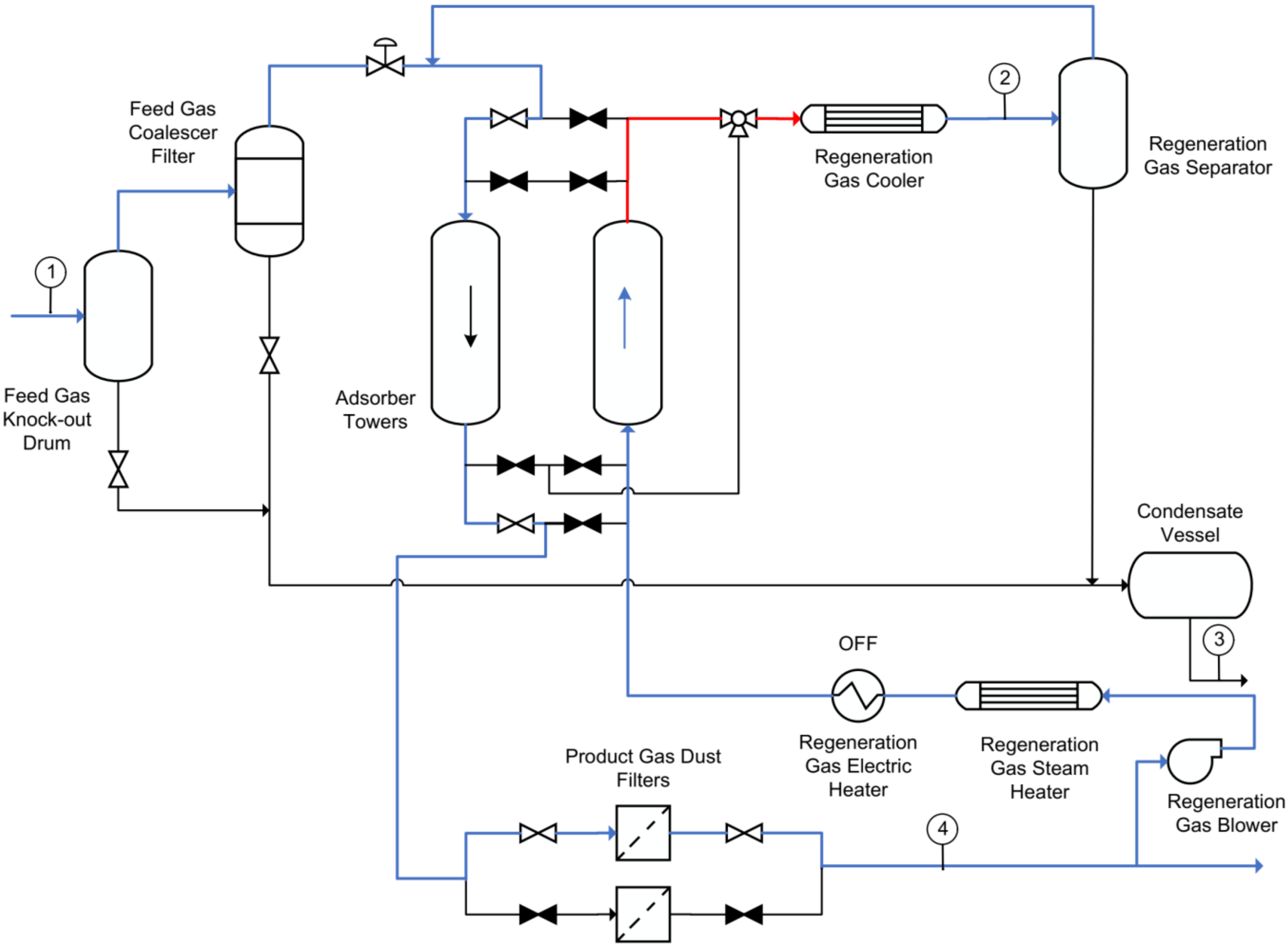


Figure 5-16 - PFD: Adsorption with Molecular Sieve, Dry Gas Regeneration, Cooling Cycle

Table 5-16 - Key stream data: Adsorption with Molecular Sieve, Cooling Cycle

Stream	1	2	3	4
Fluid	Wet CO_2 gas	Regeneration gas, dry CO_2 gas	Condensate	Dry CO_2 gas
Composition (mol%):				
CO_2	99.67	99.9999	1.70	99.9999
H_2O	0.33	<0.0001	98.30	<0.0001
Temperature (°C)	40	40	40	40
Pressure (barg)	60	60	60	~58
Mass flow (kg/hr)	228,333	39,000	negligible	228,333
Density (kg/m3)	158	158	1,004	149

5.5.1.3. Absorption with TEG

The following Process Flow Diagram illustrates the complete TEG dehydration package. The TEG Contactor, Cooler and the TEG Regeneration Module would be supplied by a vendor in a packaged state with the Regeneration Skid expected to come pre-assembled while the TEG Contactor and Cooler will come as loose equipment items. To enable the operation of this package some auxiliary equipment, utilities and tie-ins are required. These are shown in Figure 5-17 below.

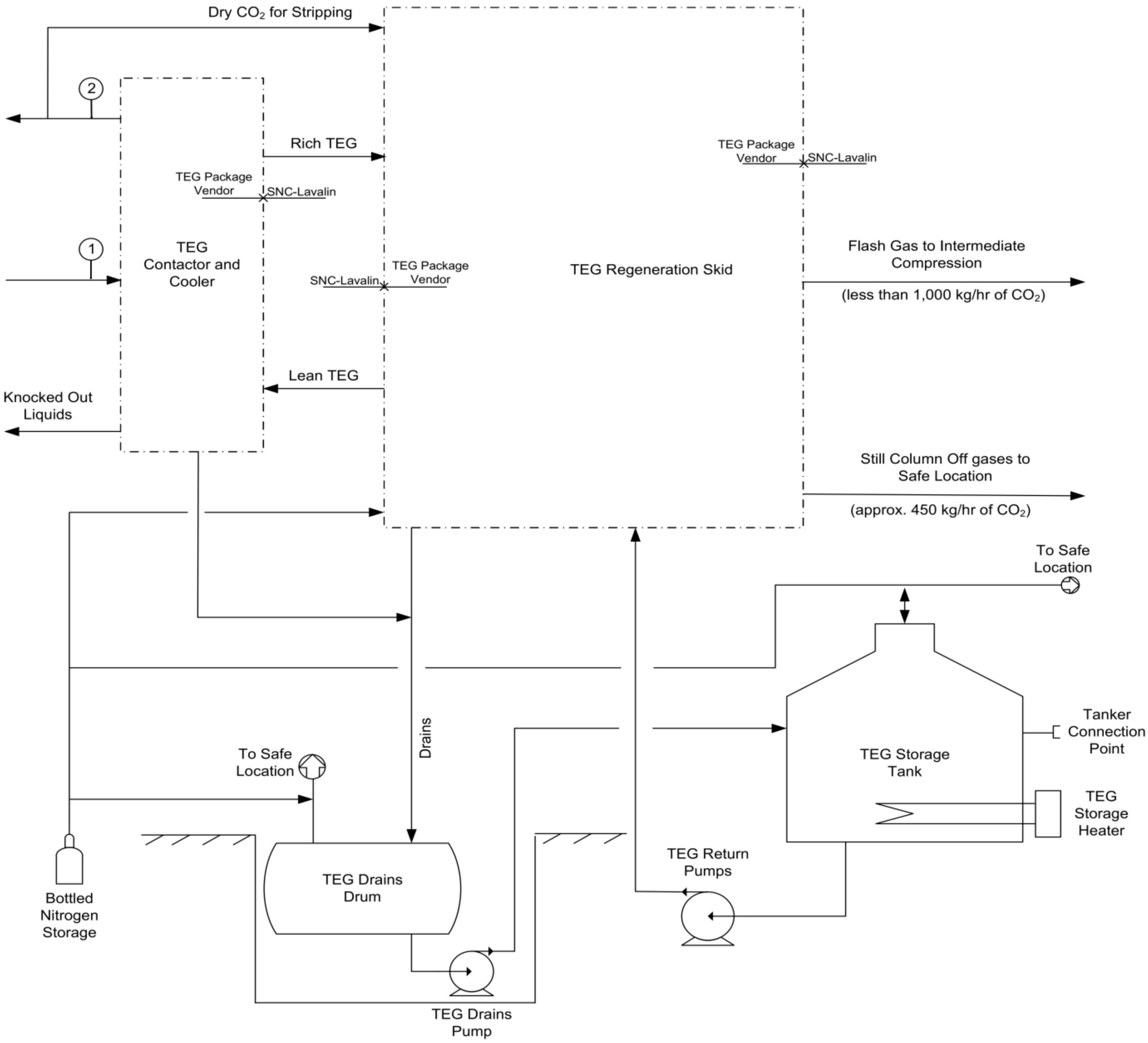


Figure 5-17 - PFD: Absorption with TEG

At this stage of the project, there is no detailed heat and mass balances due to lack of the process simulation model.

Table 5-17 - Key stream data: Absorption with TEG

Stream	1	2
Fluid	Wet CO_2 gas	Dry CO_2 gas
Composition (mol%):		
CO_2	99.67	99.9950
H_2O	0.33	<0.0050
TEG	0	<0.0002
Temperature (°C)	40	43
Pressure (barg)	45	~44
Mass flow (kg/hr)	228,333	~228,000
Density (kg/m3)	103	98

5.5.2. Process Description

5.5.2.1. Adsorption with Silica Gel

See Figure 5-13 and Figure 5-14 for a typical PFD during the heating and cooling regeneration cycles respectively.

Adsorption cycle

The wet CO_2 stream goes through the Feed Gas Knock Out Drum and the Feed Gas Coalescer Filter to separate any remaining free water from the feed gas stream. It is then passed through an adsorption bed packed with silica gel, solid desiccant, which adsorbs water.

Each train will employ a two-bed system, where one adsorber is in service and the other is being regenerated to allow continuous operation. The process is carried out in 8-hour cycles. While one bed is in adsorption mode for 8 hours, another bed is being regenerated: 4 hours of heating followed by 4 hours of cooling.

Adsorption is carried out from top to bottom to avoid fluidisation at higher gas flow rates. Dry CO_2 product gas leaves the bottom of the adsorber tower and passes through the Product Gas Dust Filters to ensure that entrained desiccant particles are removed. There are two filters per train for improved reliability and availability of the dehydration unit.

The adsorption bed packed with desiccant is eventually saturated with water removed from the wet CO_2 gas. The spent bed then must be regenerated by removing the moisture.

Regeneration cycle

The process applies the thermal swing regeneration using a slipstream from the wet feed of CO_2. The thermal swing regeneration is carried out in two cycles: heating and cooling.

The heating cycle is to ensure that all water is removed from the desiccant by heating the spent bed for 4 hours at 230°C. The regeneration gas stream is heated by a Regeneration Gas Steam Heater up to approx. 140°C, which is then topped up by an electric heater up to 230°C. The normal heating duties are around 840 kW and 645 kW respectively.

The cooling cycle must be carried out in the direction of dehydration to ensure that the wet gas does not saturate the normally dry end of the bed causing the adsorption reflux issue. This can also be avoided with dry gas regeneration.

Water released from the silica gel during the heating cycle is conveyed by the regeneration gas flow into the Regeneration Gas Cooler, with the normal cooling duty of about 1,815 kW. The gas is cooled to approx. 40°C. Condensed water is removed in the Regeneration Gas Separator vessel. Saturated CO_2 gas is returned to the inlet of the online adsorber and combined with the wet CO_2 stream. The cooled, regenerated bed can be safely brought back online in adsorption duty.

Condensate streams from the following vessels is collected in the Condensate Vessel: Feed Gas Knock Out Drum, Feed Gas Coalescer Filter and Regeneration Gas Separator.

Utilities and Connections

The utilities required for the dehydration unit are heat, power, cooling water and silica gel. It will firstly require an electrical connection, which is required for the Regeneration Gas Electric Heater. In addition, the unit will require a supply of steam, which will be used as a source of heat in the shell and tube Regeneration Gas Steam Heater to take it up to a temperature of 140°C. Cooling water is required for the shell and tube Regeneration Gas Cooler. It is recommended that an acid resistant silica gel is selected to increase replacement interval to every 4 to 5 years during a planned shutdown of the plant.

The system will also require several tie-ins. Other than tie-ins to the utilities noted above there is expected to be one inlet and two outlet connections. The inlet connection is:

- Wet CO_2 being supplied to the Feed Gas Knock Out Drum from the previous compression stage.

The outlet connections consist of:

- Dry CO_2 from the Adsorber Towers, which is sent to the next compression stage;
- Condensate Vessel outlet containing dropped out liquids from the Feed Gas KO Drum, Feed Gas Coalescer Filter and the Regeneration Gas Separator

Other aspects to be supplied in support of the unit are:

- Unit control system;
- First silica gel load; and
- Transportation from point of delivery to site.

Open Design Areas

The type of regeneration process is to be evaluated during the FEED stage. Both dry and wet gas regeneration present their advantages and disadvantages, which should be assessed in more detail. The current design assumes the wet CO_2 regeneration as an initial assumption used by vendors.

5.5.2.2. Adsorption with Molecular Sieve

Out of the three desiccant types, molecular sieves achieve the lowest gas moisture content of 0.1 ppmv, which is substantially lower than the required specification of 50 ppmv. For comparison with silica gel at 50 ppmv target moisture content, the supplier has provided the initial adsorbers design to achieve the product moisture content of less than 1 ppmv. This option will potentially allow for other emitters in the industrial hub to blend streams with moisture content of above 50 ppmv. However, the CO_2 transport network would then be fully reliant on the Drax CCS plant being operational to allow other users to discharge wetter CO_2 streams. This would then require the Drax CCS plant to operate with very high reliability and availability.

See Figure 5-15 and Figure 5-16 for a typical PFD during the heating and cooling regeneration cycles respectively.

Adsorption cycle

Similar to adsorption with silica gel, the wet CO_2 stream first goes through the Feed Gas Knock Out Drum and the Feed Gas Coalescer Filter to separate any remaining free water from the feed gas stream. It is then passed through an adsorption bed packed with molecular sieve and the water is adsorbed.

Each train employs a two-bed system, where one adsorber is in service and the other is being regenerated. The process is carried out in 12-hour cycles. While one bed is in adsorption mode for 12 hours, another bed is being regenerated: 8 hours of heating followed by 3.5 hours of cooling.

Adsorption is carried out from top to bottom to avoid fluidisation at higher gas flow rates. Dry CO_2 product gas leaves the bottom of the adsorber tower and passes through the Product Gas Dust Filters to ensure that entrained desiccant particles are removed. There are two filters per train for improved reliability and availability of the dehydration unit.

The adsorption bed packed with desiccant is eventually saturated with water removed from the wet CO_2 gas. The spent bed then must be regenerated by removing the moisture.

Regeneration cycle

In order to achieve the moisture content of less than 1 ppmv; dry regeneration is required. A slipstream of the dry product gas goes through the Regeneration Gas Blower to make up for the pressure loss within the dehydration package. A 2 bar pressure drop is assumed across the package, which requires a ~20 kW blower. The re-pressurised regeneration gas is then passed through an adsorber tower packed with molecular sieve. The thermal swing regeneration is carried out in two cycles: heating and cooling.

The heating cycle is to ensure that all water is removed from the desiccant by heating the spent bed for 8 hours at 290°C. The regeneration gas stream is heated by a Regeneration Gas Steam Heater up to approx.140°C, which is then topped up by an electric heater up to 290°C. The normal heating duties are around 1,390 kW and 1,800 kW respectively. The heating duty is almost double of that required for silica gel regeneration.

Water released from the molecular sieve during the heating cycle is conveyed by the regeneration gas flow into the Regeneration Gas Cooler, with the normal cooling duty of about 3,125 kW. The gas is cooled to approx. 40°C. Condensed water is removed in the Regeneration Gas Separator vessel. Saturated CO_2 gas is returned to the inlet of the online adsorber and combined with the wet CO_2 stream. The cooled, regenerated bed can be safely brought back online in adsorption duty.

Utilities and Connections

The utilities required for the dehydration unit are heat, power, cooling water and molecular sieve. It will firstly require an electrical connection, which is required for the Regeneration Gas Electric Heater and Regeneration Gas Blower. In addition, the unit will require a supply of steam, which will be used as a source of heat in the shell and tube Regeneration Gas Steam Heater to take it up to a temperature of 140°C. Cooling water is required for the shell and tube Regeneration Gas Cooler. Molecular sieve will have to be replaced every 3 to 4 years during a planned shutdown of the plant.

The system will also require several tie-ins. Other than tie-ins to the utilities noted above there is expected to be one inlet and two outlet connections. The inlet connection is:

- Wet CO_2 being supplied to the Feed Gas Knock Out Drum from the previous compression stage.

The outlet connections consist of:

- Dry CO_2 from the Adsorber Towers, which is sent to the next compression stage;

- Condensate Vessel outlet containing dropped out liquids from the Feed Gas KO Drum, Feed Gas Coalescer Filter and the Regeneration Gas Separator

Other aspects to be supplied in support of the unit are:

- DCS;
- First molecular sieve load; and
- Transportation from point of delivery to site.

Open Design Areas

Low pressure regeneration may be an option but will require the pressure of the dry regeneration gas to be reduced via an expander. The dry gas expansion lowers the relative humidity of the stream, which benefits the desorption of water in regeneration. The process requires a dry gas expander and may incur significant re-compression costs. The saturated regeneration gas can be recycled via the suction of the upstream wet compression stages. Further analysis would be required to confirm the most suitable regeneration option.

5.5.2.3. Absorption with TEG

The initial design of a TEG unit has been split into a number of sections with the TEG Contactor and Cooler supplied by the TEG Package vendor as loose items alongside the skid mounted TEG Regeneration Package. This is supported by auxiliary equipment, necessary utilities and appropriate connections. A description of the process is provided below.

TEG Contactor and Cooler

The wet CO_2 stream is fed through the TEG Contactor column, which flows counter-currently to the lean Tri-Ethylene Glycol (TEG). TEG absorbs the excess moisture content down to 50 ppmv. The wet CO_2 enters the bottom of the column, where any free liquids are knocked out and removed from the Contactor. The dry CO_2 leaving the contactor cools the lean TEG entering the column in the TEG Cooler.

For this application, the operating pressure of the TEG Contractor should be in the range of 40 to 50 barg. At 40°C and 60 barg, the contactor column will operate close to the CO_2 liquid phase. There is a risk of the CO_2 condensation in case of the operating temperature upset and higher TEG losses in the dehydrated CO_2. This lower operating pressure has small impact on the design of the TEG unit since operating at 60 barg instead of 45 barg only reduces by approx. 10-15% the water saturation content of the CO_2 feed.

TEG Regeneration Skid

Rich TEG leaving the bottom of the contactor is then regenerated to remove the water so that it can be re-used in the contactor column. This regeneration is achieved by heating and reducing the pressure of the TEG in two stages. In the first stage, the TEG is heated by cooling the Still Column Overheads (see below) and routed to a flash drum. In this drum absorbed CO_2 is flashed off (i.e. the total of less than 1,000 kg/h CO_2) and recycled back to an intermediate compression stage of the main CO_2 compressor. In the second stage, the TEG is further heated in a Lean/Rich TEG Exchanger before being routed to a Still Column where the pressure is further reduced. The Still Column is provided with the electrically powered TEG Reboiler to desorb the water. Vendors advise that the reboiler duty is to be fully powered either with electricity or steam. Since LP steam is not sufficient to reach 204ºC, MP steam would be required for heating. The choice of the reboiler will be further considered during the next stage of the project.

The rich TEG is then used to cool the overheads from the Still Column providing reflux in the column, which prevents excessive TEG losses in the overheads. Off gases leaving the Still Column are routed to a vent in a safe location. This off-gas contains CO_2 that will be emitted to atmosphere. The total of about 450 kg/hr CO_2 is currently estimated, which is about 0.1% of the CO_2 feed to be treated. When leaving the Reboiler, TEG passes through a stripping section in the Reboiler, which uses dry CO_2 from the contactor, to further reduce the water content in the Lean TEG. An alternative option is to use flash gas as the stripping gas.

The lean TEG is then passed through the Lean/Rich TEG Exchanger, where it is cooled before being routed to the TEG Surge Drum. The lean TEG is then pumped back to the TEG Cooler.

Auxiliary Equipment, Utilities and Connections

The above equipment will come from the Vendor as a package with the Regeneration Skid expected to come pre-assembled while the Contactor and Cooler will come as loose equipment items. To enable the operation of this package some supporting equipment, utilities and tie-ins are required. These are shown in Figure 5-17 and discussed further below.

Each package will be provided with a TEG drains drum which will collect drains from a number of locations throughout that package unit. This drum will be situated below grade and will be used as the location to drain TEG to during the process of shutting down the unit. It will be sized to provide sufficient volume, above the high level alarm point, to permit operators time to take action to prevent overfilling. The pressure in the drum will be maintained slightly above atmospheric by a connection from the nitrogen system. This will prevent air ingress during normal operation which can degrade TEG. The drum will be vented to atmosphere at a safe location as TEG is non-flammable and thus does not need to be flared.

The Drains Drum will be provided with a single Drains Pump. This will be used to pump any TEG collected within the Drains Drum to the TEG Storage Tank and is likely to work off automatic level control. Only a single pump will be provided (i.e. no duty/spare) as this pump is not in operation for the majority of the time thus maintenance access is not an issue.

The system will also be provided with a TEG Storage Tank. This tank has dual purposes, firstly it will be used during a shutdown to hold the TEG while maintenance is carried out on the rest of the unit. Secondly, it is the destination for fresh imported TEG. It will be sized to hold the volume of TEG contained in one of the 50% trains, which has been estimated by the package vendor as 20m^3. In addition, a further allowance is made to permit a single delivery of TEG, the volume of these deliveries is currently unknown however a delivery of 5m^3 would allow for monthly supplies and is considered a reasonable estimate at this stage. As such the total volume required is 25 m^3 plus any margins for alarm levels, head space etc. Only a single TEG Storage Tank will be provided for both 50% TEG trains, this will require that suitable planning is undertaken to prevent the shutdown of both TEG trains simultaneously but allows the use of a smaller TEG Storage Tank and its associated plot space/CAPEX savings. As per the drains drum the pressure in the TEG Storage Tank will be maintained at slightly above atmospheric by a nitrogen supply to prevent air ingress and degradation of the TEG. The TEG Storage Tank will also be vented to atmosphere at a safe location.

The TEG Storage Tank will be provided with an electric heater which will be used during winter to prevent the TEG temperature dropping too low and becoming un-pumpable. This heater will ultimately be sized to maintain an acceptable temperature within the tank but at this stage the required duty is unknown. As such it is assumed a 10 kW heater will be sufficient to maintain the TEG at an acceptable temperature. The TEG Storage Tank will also be provided with duty and spare TEG Return Pumps which are able to return TEG to either of the TEG Units into the TEG Surge Drum. These pumps will be sized to provide ~5 tonnes/hr of TEG, this minimises the fill time for the unit whilst being below the 5.25 tonnes/hr achievable by the TEG Circulation Pumps. The TEG Storage Tank will also be provided with a tanker connection point which will allow the delivery of fresh TEG.

The utilities required for the TEG unit are fairly minimal. It will firstly require an electrical connection which is required for the Still Column Reboiler as well as any other electrically operated equipment (e.g. pumps, TEG Storage Heater etc). In addition, the unit will require a nitrogen supply which will be used to maintain an inert atmosphere in several of the vessels in order to prevent air ingress. Nitrogen is expected to be required for the TEG Flash Drum, TEG Drains Drum and TEG Storage Tank. In all cases it is expected that the nitrogen requirement will be small and thus bottled nitrogen is considered the preferred solution rather than delivery of liquid nitrogen or construction of a nitrogen generation unit.

The system will also require several tie-ins. Other than tie-ins to equipment and utilities noted above there is expected to be one inlet and four outlet connections as well as three inter-connections between the TEG Contactor/Cooler and the TEG Regeneration Skid. The inlet connections consist of:

- Wet CO_2 being supplied to the TEG Contactor from the previous compression stage; and

The outlet connections consist of:

- Dry CO_2 from the TEG cooler which is sent to the next compression stage;
- Knocked out liquids from the TEG Contactor;
- Flashed gas from the flash drum, which will be routed back to an earlier compression stage (expected to be at ~3.5 barg); and
- Off gases from the Still Column which will be routed to a safe location.

The interconnections consist of:

- Lean TEG from the TEG circulation pumps in the Regeneration Skid to the TEG Cooler;
- Rich TEG from the TEG contactor being routed to the Still Column Overheads Condenser; and
- Dry CO_2 from the contactor being routed to the Still Column Reboiler Stripping Section.

Other aspects to be supplied in support of the unit are:

- Unit control system;
- MCC (and associated Power Cables from MCC to skid with all on skid cabling by skid fabricator);
- First TEG load and any other required chemicals; and
- Transportation from point of delivery to site.

Open Design Areas

As would be expected at this stage in the project there are a number of areas where the design is still open and subject to change during the FEED stage, these are discussed below.

The stripping medium in the reboiler was specified by the vendor as dry CO_2. Although this would perform the intended function the dry CO_2 supply is at ~45 barg and would require dropping down to the ~0.3 barg of the reboiler operating pressure. An alternative approach is to use the flash gases from the Flash Drum, which should be able achieve an outlet TEG purity of >99%.

As noted in the TEG Package Vendor's Process Description, the lean TEG is cooled by exchanging it against the outgoing dry CO_2. Using the dry CO_2 as a cooling medium results in the CO_2 outlet temperature being higher than the inlet temperature and based on vendor estimates it is expected to leave the package at 43°C (against an inlet temperature of 40°C). Raising the temperature of the outlet CO_2 will result in an increased duty on the next compression and cooling stage and must be factored into the design. It is noted that the TEG unit could alternatively use cooling water or air cooling to cool the lean TEG and thus have a lower CO_2 outlet temperature. The 3°C temperature rise is not expected to be significant to the overall plant operation but should be investigated further during the FEED.

The package vendor has raised the possibility that off-gases from the still column could be recycled back to earlier stages of the compression rather than vented. This would result in a greater recovery of CO_2 and the increased recovery of water in the compressor KO pots. However, such a design is likely to require a blower in order to work and thus would result in an increased CAPEX and OPEX. The potential for this will be investigated during the FEED to identify if the improved CO_2 recovery is worth the additional costs.

A further open design area is the selection of the TEG Circulation Pumps. These pumps pump TEG from the Surge Drum (at ~0 barg) to the Contactor pressure (~45 barg) and thus have an extremely high pressure differential. Due to the onerous operating conditions these pumps are a potentially problematic area in a TEG unit. As such care should be taken when specifying these pumps.

The final area under consideration is the potential requirement for chemical injections to the system. Potential chemicals may include pH control chemicals and/or antifoaming agents to improve the operation of the plant. Any requirement for chemical injections will be discussed with the selected TEG package vendor during FEED.

5.5.3. Major Equipment List

The major equipment items within the three dehydration package options are listed below.

5.5.3.1. Adsorption with Silica Gel

- Feed Gas Knock Out Drum
- Feed Gas Coalescer Filter
- 2 Adsorber Towers (1 adsorbing, 1 regenerating)
- Regeneration Gas Steam Heater
- Regeneration Gas Electric Heater
- Regeneration Gas Cooler
- Regeneration Gas Separator

- Product Gas Dust Filters (2 x 100%)
- Condensate Vessel

5.5.3.2. Adsorption with Molecular Sieve

- Feed Gas Knock Out Drum
- Feed Gas Coalescer Filter
- 2 Adsorber Towers (1 adsorbing, 1 regenerating)
- Regeneration Gas Steam Heater
- Regeneration Gas Electric Heater
- Regeneration Gas Cooler
- Regeneration Gas Separator
- Product Gas Dust Filters (2 x 100%)
- Condensate Vessel
- Regeneration Gas Blower

5.5.3.3. Absorption with TEG

TEG Contactor and Cooler

- TEG Contactor
- Lean TEG Cooler

TEG Regeneration Skid

- TEG Flash Drum
- Lean/Rich TEG Heat Exchanger
- TEG Still Column
- TEG Reboiler
- Reboiler Stripper
- Still Column Condenser
- TEG Surge Drum
- Lean TEG Pumps (2 x 100%)
- Lean TEG Filters (2 x 100%)

Auxiliary Equipment

- TEG Storage Tank
- TEG Return Pump
- TEG Drains Drum
- TEG Drains Pumps

5.5.4. Operations & Maintenance Philosophy

The Operations and Maintenance (O&M) philosophy is intended to give an overview of the way in which the CO_2 dehydration unit will be operated, to describe the operational requirements to be applied to the design, and to document the philosophy for maintenance of the units. At the early stage of the project, vendors have not provided a typical maintenance schedule for their proposed designs. This is usually done at the FEED stage when the process equipment is specified, and the information is gathered from all equipment suppliers. At this stage the O&M philosophy is focusing on the following aspects:

- Availability and reliability;
- Turndown capability; and
- High level maintenance requirements.

5.5.4.1. Availability/Reliability

Typical availability of the TEG unit is 98.5% excluding planned shutdown for inspections requested by local regulations. During planned shutdowns, it is recommended to check internals of the different columns and the reboiler and to clean them if necessary.

Adsorption plants are inherently reliable, often quoted with greater reliability and availability figures than glycol plants and especially when competing against dehydration and dew point control processes with rotating machinery equipment items. The typical reported availability for a solid bed adsorption plant with this configuration scheme is approximately 99%.

As a standalone unit, adsorption plants tend to have better start-up and load following characteristics. Regarding start-up, glycol units usually have to be on hot standby to be immediately ready to receive gas, whereas adsorption plants can be started up as simply as opening up the inlet valve. When gas properties change (concentration levels, flowrates, pressures and temperatures), adsorption plants can carry on running without operational set point changes unlike a glycol unit where increased glycol circulation rate, reboiler duty adjustments will be required. Adsorption plants are also dry processes so this eliminates the risk of liquid entrainment downstream from wet processes which occurs with glycol systems.

However, TEG units are often preferred by the CO_2 compressor vendors, due to their robustness against pressure ramps which can be seen at start-up and shutdown procedures. In comparison, an adsorption package will need to be completely isolated from the compressor for shutdown and start-up, as pressure ramps are not acceptable to the drier bed [3].

In terms of maintenance items, adsorption units use trunnion mounted ball valves as the switching valves which have a reputation for high reliability and robustness. Filter cartridge replacement is designed to be executed without plant shutdown (2 x 100% housings) to further avoid any reduction in plant availability.

Spent desiccant can be replaced and disposed of at every planned shut-down with no additional outage time required.

5.5.4.2. Turndown

With regards to the dehydration unit turndown, both adsorption and absorption technologies can achieve a wide turndown of a single train (1x100%). The turndown capability is 10-100% and 30-100% for absorption and adsorption respectively. The two trains at 50% capacity (2x50%) will be able to achieve 5-100% and 15-100% turndown respectively. Thus, both train configurations can achieve the required minimum turndown of 33%.

5.5.5. Utility Summary

The utilities required for the three dehydration package options are summarised below.

5.5.5.1. Adsorption with Silica Gel

Table 5-18 – Utility summary - Adsorption with silica gel – 2x50%

Utility	Normal Consumption Rate	Unit	Yearly Consumption Rate	Unit
Power	1,290	kW	4,803	MWh
Heat duty (steam)	1,678	kWth	213,164	therm/y
Cooling Water	250	m3/h	931,142	m3/y
Chemicals	-	kg/h	7	t/y

5.5.5.2. Adsorption with Molecular Sieve

Table 5-19 – Utility summary - Adsorption with molecular sieves – 2x50%

Utility	Normal Consumption Rate	Unit	Yearly Consumption Rate	Unit
Power	3,640	kW	18,069	MWh
Heat duty (steam)	2,780	kWth	470,875	therm/y
Cooling Water	431	m3/h	3,206,411	m3/y
Chemicals	-	kg/h	64	t/y

5.5.5.3. Absorption with TEG

Table 5-20 – Utility summary - Absorption using TEG – 2x50%

Utility	Normal Consumption Rate	Unit	Yearly Consumption Rate	Unit
Power	870	kW	6,478	MWh
Heat duty (steam)	-	kWth	-	therm/y
Cooling Water	-	m3/h	-	m3/y
TEG	8	kg/h	104	t/y
Nitrogen	0.2	m^3/hr	1,551	m^3/y

5.5.6. Plot Size

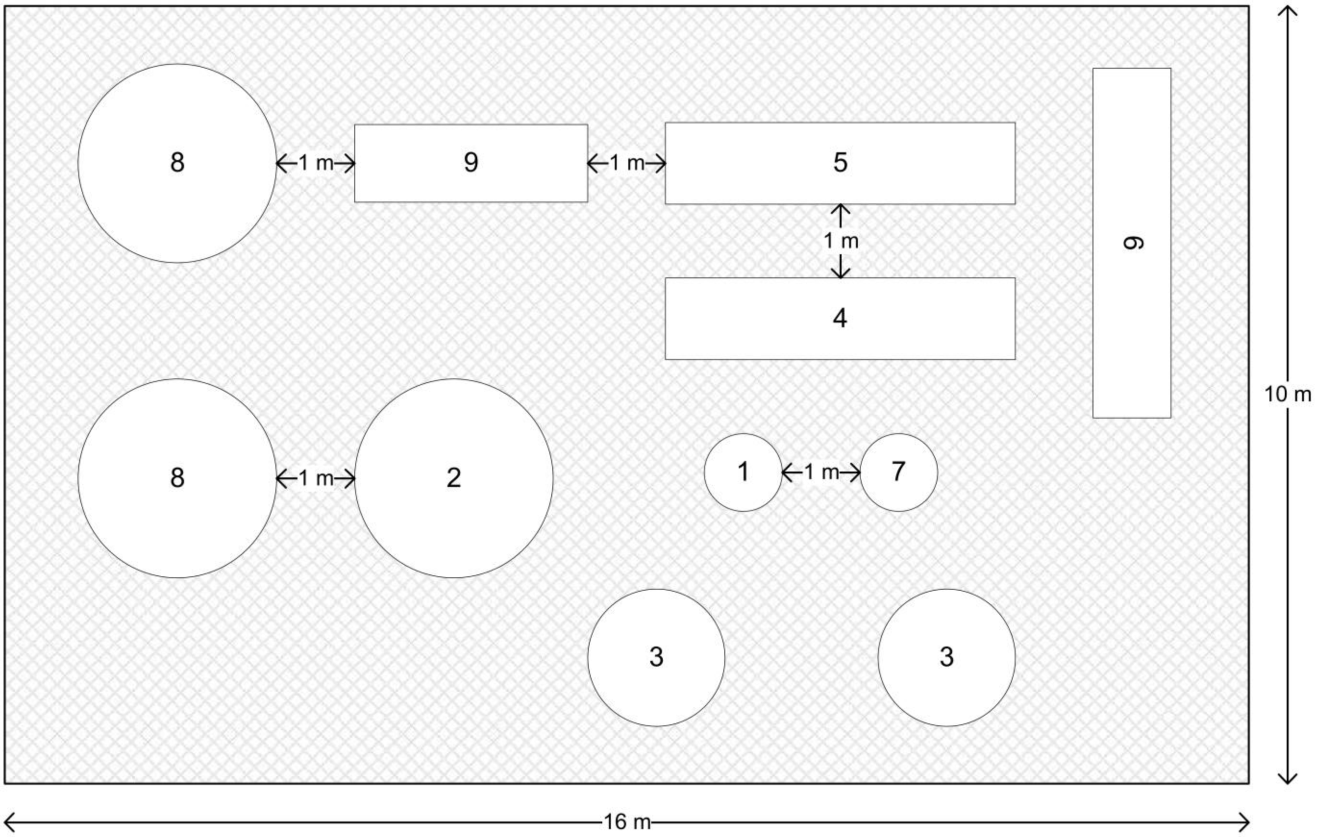
The following section shows the rough plot sizes of the three dehydration technology options: adsorption with silica gel and molecular sieve, and absorption with TEG. For clarity, the tanks and vertical vessels are illustrated as circles, and horizontal vessels, heat exchangers and pumps are illustrated as rectangles.

The following assumptions have been made:

- The separation distance between equipment is no less than 1 m.
- Heat exchangers should have enough space around them to allow maintenance, to remove the tube bundles. Thus, the separation distance is no less than the length of the heat exchanger shell.

5.5.6.1. Adsorption with Silica Gel

Figure 5-18 illustrates a rough plot plan for a single 50% silica gel adsorption train. The total plot footprint is approx. 160 m^2.

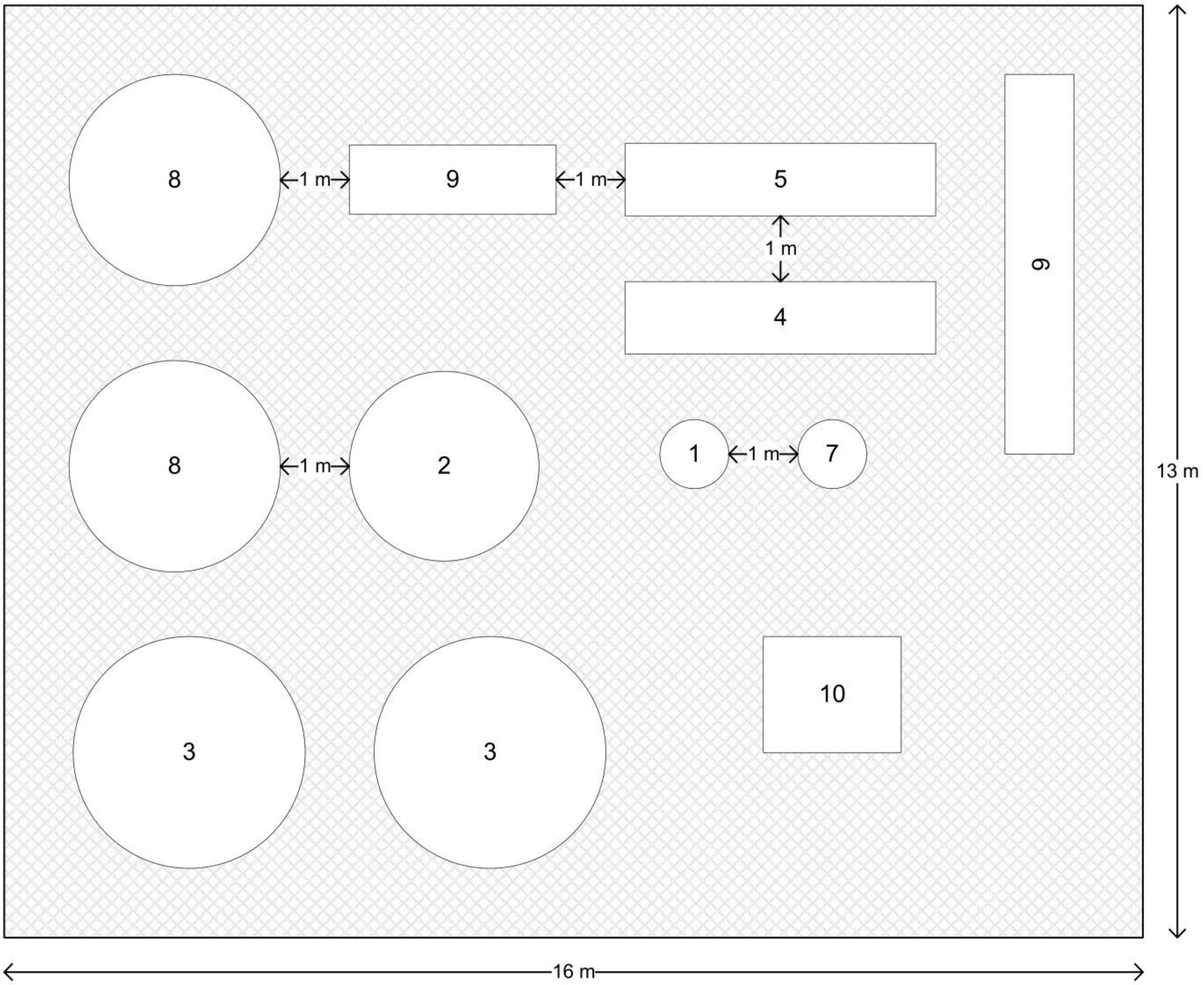


Mark	Description
1	Feed Gas Knock Out Drum
2	Feed Gas Coalescer Filter
3	Adsorber Tower
4	Regeneration Gas Steam Heater
5	Regeneration Gas Electric Heater
6	Regeneration Gas Cooler
7	Regeneration Gas Separator
8	Product Gas Dust Filters
9	Condensate Vessel

Figure 5-18 - Plot Plan - Adsorption with silica gel

5.5.6.2. Adsorption with Molecular Sieve

Figure 5-19 illustrates a rough plot plan for a single 50% molecular sieve adsorption train. The total plot footprint is approx. 210 m^2.

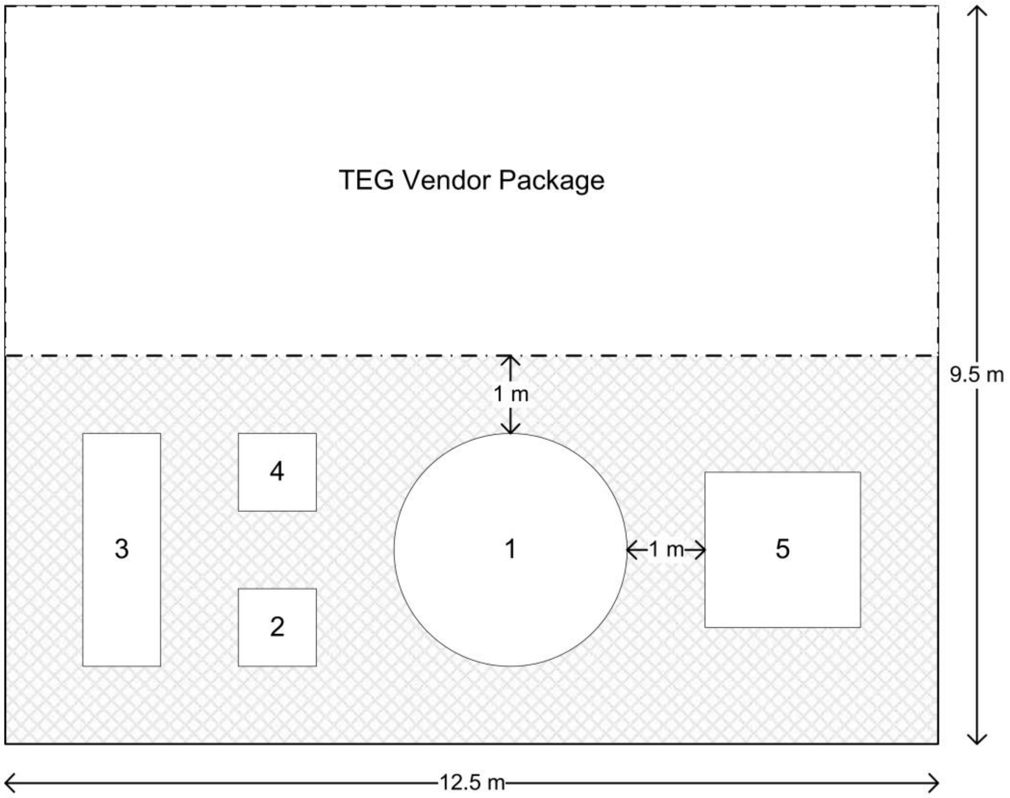


Mark	Description
1	Feed Gas Knock Out Drum
2	Feed Gas Coalescer Filter
3	Adsorber Tower
4	Regeneration Gas Steam Heater
5	Regeneration Gas Electric Heater
6	Regeneration Gas Cooler
7	Regeneration Gas Separator
8	Product Gas Dust Filters
9	Condensate Vessel
10	Regeneration Gas Blower

Figure 5-19 - Plot Plan - Adsorption with molecular sieve

5.5.6.3. Absorption with TEG

Figure 5-20 illustrates a rough plot plan for a single 50% TEG absorption train. The total plot footprint is approx. 120 m^2.



Mark	Description
1	TEG Storage Tank
2	TEG Return Pump
3	TEG Drains Drum
4	TEG Drains Pumps
5	Bottled Nitrogen Storage

Figure 5-20 - Plot Plan - Absorption with TEG

5.6. HSSE Hazards (HAZID ENVID)

A desktop HAZID/ENVID for the CO_2 compression and dehydration facilities was successfully completed during Stage 2. The HAZID/ENVID followed our predefined process and considers potentially novel aspects such as risks associated with a CO_2 release. Please refer to Appendix A for a copy of the HAZID/ENVID report.

6. Cost estimate (Class IV)

6.1. Capital Cost Estimate Basis

The stage 2 work has estimated project costs for each option to an Association for the Advancement of Cost Engineering International (AACEI) Class 4 level as defined in the AACEI 18R-97 guidelines. The approach utilised for the estimating is outlined below and follows the standardised process used by Atkins, based on a feasibility level study and scope of engineering work.

6.2. Scope

To estimate the capital cost for each of the selected options for the compression plant and dehydration units, Atkins developed an overall concept design and made enquiries with vendors to obtain budget quotations for the major equipment. The vendor scope of supply and costs were reviewed, and any items of equipment required not included in vendor scope were designed and sized by Atkins. The vendor data and Atkins generated major equipment lists were provided to the cost engineer as an input to the cost estimation exercise following standard Atkins processes.

Details of the concept design for the various compression and dehydration options are detailed in section 5.

6.3. CAPEX

Estimate classes are characterised within the Association for the Advancement of Cost Engineering International (AACEI) 18R-97 guidelines. An estimate based on a concept study with a project definition between 1 and 15% would be categorised as a Class 4 Estimate, meaning the overall accuracy could be expected as -15% to – 30% and +20% to +50%. A Class 4 estimate is prepared when available documentation includes process flow diagrams, plant capacity, block schematics, layouts, and major equipment lists. With this level of estimate, costs are most often built up using system and equipment costs and applying equipment factors, Lang factors, and estimating norms and benchmarks. It is not customary to appeals for vendor quotes for a Class 4 estimate under the AACE guidelines; however, Atkins have approached vendors to obtain data relating to the compression and dehydration scopes for this study due to the annual throughput being greater than previous realised projects. Therefore, it was appropriate to engage with vendors to understand the products and technologies offered by them to meet the requirements, as scaling and utilisation of parametric estimates would not account to limitations in products available for vendors. This was also relevant to investigating the impact of varying inlet CO_2 conditions as this impacts the specific model that may be selected by each manufacturer.

6.4. OPEX

Although the AACEI guidelines refer to CAPEX estimates, the same methodology is applied in the case of OPEX estimates. Estimates from Operations and Maintenance contracts, proposals, and budgetary estimates were used wherever possible, including unit pricing for utilities and consumables. Failing applicable vendor quotations, internal estimating databases are employed. As a last effort, factors and norms may be applied to complete a comprehensive estimate. Assumptions around availability and reliability were determined in coordination with stakeholders, and factors will be clearly stated on the OPEX estimate.

6.5. Key Assumptions and Exclusions

The Key CAPEX estimating assumptions are set out below:

- Atkins utilised current cost information for major equipment from our internal procurement and estimating records as a primary source of cost data.
- Where Atkins does not have current cost information for key equipment items, budgetary quotations were requested from vendors (where readily available within project timescales).
- Equipment pricing was based on the specifications included in the Major Equipment List (MEL).
- Estimates were based on UK currency. Exchange rates utilised for the development of estimates were:
    - USD:GBP– 1.29
    - EUR:GBP – 1.17

- Costs for permits and applications made to government and regulatory bodies are not included in the estimate.
- Costs for FEED design development have been excluded from the estimate.
- Owners soft costs for post FID delivery are included (i.e. project management, owners engineering etc)
- Site assumed to be cleared (i.e. demolished, underground services removed)
- CAPEX Estimate will include civils with expectation piling will be required (another Drax project identified areas of made ground so piling of general foundations will be required heavy foundations for columns compressors etc. certainly required)
- CAPEX estimate is based on battery limits at the boundary of the compression or dehydration unit. No tie-in infrastructure is included.
- No issues with site access for heavy lift equipment of large modules/plant
- Plant contracting strategy EPC Lump sum turn key.

The key OPEX assumptions are set out below:

- Gas unit price of 62p/therm (Annex M - Price Growth Assumptions May 2019 (BEIS))
- Electricity unit price of Confidential £/MWh (Drax Agreed value for power in 2027)
- Cooling water unit price of 6.5p/m^3(https://www.intratec.us/chemical-markets/cooling-water-cost)
- Demineralised water Confidential £/m^3 (Drax value)
- Nitrogen unit price of Confidential £/m^3 (Atkins estimate)
- All staffing costs for operation and maintenance are excluded as they will be estimated by Drax based on an increase of existing staffing levels.

6.6. Estimating Approaches for a Class 4 Estimate

6.6.1. Level of Effort Estimating

Level of Effort estimating involves a calculation of manpower / headcount over a planned period of time. It may be used for areas such as field support or project management office. It is easy to understand; however, its accuracy is dependent on the experience of the project team.

6.6.2. Discrete Estimating

Discrete estimating includes creating a detailed bottom-up estimate using the best available engineering documents, such as specifications, scopes of work, engineering drawings, and equipment lists. A discrete estimate is task and man-hour based and provides a higher level of accuracy than a level of effort estimate provided the knowledge and experience of those preparing the estimate is sufficient.

6.6.3. Comparative (Analogous) Estimating

In comparative estimating, costs for similar projects/programmes are used and adjusted to reflect technical, geographical, and physical differences between the source data and new project. Prior project data is collected and factors are garnered from the information. These cost factors are then applied to the new model to create the estimate. Actual costs may be adjusted with inflation and/or efficiency factors.

This method provides a good degree of accuracy; however, differences in scope, design, and layout are common, and may be difficult to assess in comparing programs.

6.6.4. Standards Estimating

Standards estimating is a technique based on standard work unit measurement techniques. In this instance, standard work hours or per unit costs can be found from industry published data, such as SPONs guides or from purchased or internal estimating software packages.

6.6.5. Historical Estimating

If sufficient historical data is available for similar projects or elements of a project and technical engineering data is available for both, historical estimating may be employed. In this instance, labour and material costs from prior projects can be assessed and applied to the new project.

This method provides a good degree of accuracy; however, differences in scope, design, and layout are common, and may be difficult to assess in comparing programs. It provides a greater level of detail and higher level of accuracy than analogous estimating, but a higher level of project definition is required.

6.6.6. Parametric Estimating

Parametric estimating is the process of estimating costs based on a mathematical model that relates a set of costs to physical or technical variables (i.e. Pump size) in order to determine a cost based on the new project variables. With a large set of data to support it, parametric estimating provides a good degree of accuracy and is efficient in its preparation.

This type of estimating lends credibility to an estimate as it factors in many examples of historical costs and focuses the comparisons on tangible and measurable variables between historical data and the new project scope. Parametric estimating is used at a semi-detailed level (major equipment and labour), provides consistency in estimating, and provides flexibility in estimating areas of scope which are similar but not identical.

6.6.7. Equipment Factored Estimating

This type of estimating looks at the cost of equipment and apply an Installation factor to arrive at the total installed cost for that equipment. The Lang Method and the Hand Method are examples of this type of estimating which apply factors to process equipment costs to arrive at a final estimate ((Lang), (Hand)).

6.7. Areas of Estimation

The key areas of estimation will be determined by review of the Process Flow Diagrams (PFDs), layouts, and grouped in a work breakdown and cost breakdown structure that will support a clear estimating and scheduling basis. These areas will be further broken down into Project and Construction Management and Indirects, Early Engineering and Detailed Design, Site Preparation and Enabling Works, Major Equipment, Bulk Materials, Labour (to mechanical completion), Pre-Commissioning, and Commissioning to Turn-over. Owner's costs are included in the estimate and will be detailed in the estimates. Land take and development costs (surveys, planning, consenting) are excluded from the estimate.

The CAPEX and OPEX estimates will be broken down into three cost areas, with additional cases detailed in each area:

- CO_2 Compression
- CO_2 Dehydration
- CHP Unit

6.8. Development of Estimate

6.8.1. CAPEX Estimate

The development of the Class IV estimate has relied on a combination of the estimating techniques discussed above. Engineering document registers, plant layouts, major equipment lists, and utilities schedules are some of the documents required to development Class IV estimate.

The estimate has been built up in sections based on the concept design for each area, see section 6. The major processing areas have been separated in the estimate to align with the scope of Work detail, and sections added to cover common areas and systems.

Using the major equipment list, block diagrams, and layouts as a basis, an estimate template is developed based on a defined WBS structure. The template is then populated as data becomes available, beginning with the major equipment and costs. Costs for major equipment have been generated from Atkins prior project and proposal data, supplemented with updated vendor budgetary estimates. From there, fabrication costs, installation costs, bulk materials, and subcontracts have been estimated using the techniques above.

The overall project estimate has been peer reviewed and subject to scrutiny through Atkins's internal review process. It has been further assessed based on benchmark data available to ensure cost data is commensurate to similar projects.

6.8.2. OPEX Estimate

The development of the OPEX estimate has been based on the principles of the AACEI guidelines for a Class 4 Capital Cost estimate, and include the estimating techniques discussed above. The documents and information used were the utilities schedule and operability assumptions including availability and reliability.

Costs for utilities, disposals, and consumables have been based on the information in the utilities summary, and built up using current unit rates. Maintenance costs have been developed based on information from vendors and internal estimating data; however, exclude routine maintenance performed by existing site staff.

6.8.3. Data Sources

Cost data for the project has been gathered from Atkins prior project and proposal data and includes relevant information for UK EPC projects, recent UK compression and storage projects, current building and subcontract costs, and a large range of equipment pricing.

Due to the nature of the information, confidentiality agreements with vendors will need to be honoured, and as such, the source data cannot be shared at a detailed level.

6.9. Benchmarks

A benchmarking exercise has been undertaken as a part of the estimating and Pre-FEED process. Both technical/performance and cost benchmarks will be researched and used to determine whether the estimate falls within a reasonable parameter based on the technical, geographical, and physical characteristics of the plant.

Benchmarking data will be garnered from Atkins prior project experience as well as publicly available sources.

6.10. Operational Cost estimate Basis

The operational costs (OPEX) have been calculated based on the utility requirements for each of the compression and dehydration conceptual design options developed. The costs associated with operational manpower required have been excluded on the basis that manning would be for the overall carbon capture plant, i.e. including the capture unit. It is also expected that the manning would be an augmentation to the existing resources available at site, Drax are therefore best placed to estimate the additional manpower required.

The maintenance costs element of the OPEX have been estimated on an equipment only basis with the manpower element excluded as further study and collaboration with equipment vendors is required to understand typical manpower requirements to meet the maintenance schedule for the major equipment.

The key assumptions agreed with Drax for the calculation of OPEX are:

6.10.1. Compression and Dehydration

The compression and dehydration operational costs have been calculated on the basis that:

1. Power is taken at the unit price given above
2. Heat cost has been calculated based on the heat being supplied from gas boilers. Conversion of heat required to gas demand has been based on the following:
    a. A gas boiler efficiency of 84% (HHV basis)
    b. An allowance of 5% for losses from heat exchangers and in the distribution system.
3. Cooling water is taken from existing facilities but the cost per unit is assumed to be as above to account for pumping and treatment costs.
4. Maintenance spares have been estimated as being 1% of equipment cost per annum.

6.11. Project Risk Register

Project risks have been considered in the development of the capital cost estimate and the associated uncertainty in expected project out turn cost. A list of top project risks was developed in collaboration with Drax staff during the Stage 2 Interim review. The risk identified are detailed in Table 6-1.

Table 6-1 - Top 6 Project risks

	Item	Impact (£m)	Likelihood	Notes
1.	Euro/Dollar exchange rate in relation to sterling	3-5	50%	10% of CAPEX
2.	Failure of project partner or contractor to deliver	3-5	5%	Need to appoint completion contractor
3.	Lack of EPC competition (high EPC premium)	1-3	60%	Based on complete capture plant EPC.
4.	Lack of technology supplier competition	1-3	5%	Good competition for main packages
5.	Weather risks	1-3	5%	UK build longer than 1 year duration.
6.	Technology fails to perform – the complexity of some of the solutions may jeopardise availability	5-10	3%	Compression/dehydration established technology

6.12. Capital Cost Estimate Summary

The summary of the proportional total CAPEX estimated for each option is as follows:

Table 6-2 - Proportional CAPEX Estimate Summary

Option	Proportional CAPEX
Compression	
Case 1, 2 x 50% (0.6 barg) IG Compressor	100%
Case 2, 2 x 50% (2 barg) IG Compressor	90%
Case 3, 2 x 50% (3 barg) IG Compressor	70%
Case 4, 1 x 100% (0.6 barg) IG Compressor	61%
Dehydration	
TEG	100%
TEG Alternative	88%
Molecular Sieve Adsorption	90%
Silica Gel Adsorption	73%

6.12.1. .Licensor and Major Equipment Packages

Significant portions of the plant areas (Compression and Dehydration) are included in individual licensor packages, for which cost estimates have been provided by the selected licensors and vendors.

The licensor and major equipment packages account for approximately 42% of the total project cost for each case. The mark-ups on major packaged equipment are based on the Contractor assuming a lump sum turn-key risk on the full vendor packages, with no procurement done by the owner.

6.12.2. Other Equipment

Major equipment items have been estimated based on Atkins estimates from prior projects and proposals for similar equipment. Further details on minor plant equipment will be required in subsequent engineering phases. Costs for additional minor equipment are assumed to be included in the bulk material factors.

6.12.3. Bulk Materials

Bulk materials have been estimated as a percentage of equipment costs using a factored estimating basis. Different sets of factors have been used depending on the extent of the licensor involvement in installation and connection of equipment and packages and vary between units based on experience on prior projects, costs included in previous EPC proposals, and the experience of the consultant estimator. The material to labour ratios within each bulk material line item are based on industry standards as follows:

Table 6-3 - Bulk Material Factors

BULK MATERIAL FACTORS		LABOUR	
	MATERIAL COST (%)	**FABRICATION COST (%)**	**INSTALLATION COST (%)**
Civil work	+/- 5-10%	- -	+/- 95 - 90 %
Concrete work	+/- 35%	- -	+/- 65 %
Structural Steelwork	+/- 25%	+/- 50%	+/- 25%
Building work	+/- 30%	- -	+/- 70 %
Mechanical Equipmt.	Separate	Incl. in Mat'l Cost	+/- 8 - 12 % of
Piping work C.S.	+/- 40%	+/- 30 - 35 %	+/- 30 - 25 %
Electrical (bulk)work	+/- 40%	- -	+/- 60 %
Instrumentation work	+/- 35%	- -	+/- 65 %
Painting work	+/- 50%	- -	+/- 50 %
Insulation / Lagging work	+/- 45%	- -	+/- 55 %
Scaffolding	+/- 20%	- -	+/- 80 %
	(rental)		(assembly + removal)

The indicative labour rates above are for reference and comparison only and include a 19-25% uplift for contractor's soft costs. This element has been separated in the detailed estimate and represented in a stand-alone line for Contractor's Soft Costs.

6.12.4. Commissioning

Commissioning costs are factored based on Atkins historical EPC pricing and prior project costs. Owner's commissioning sources of information have been limited to disclosure by project owners on prior projects. Details of these calculations are limited by confidentiality agreements with prior projects. The lower end of the range is used when the licensor/equipment provider has specified commissioning and commissioning support within scope.

6.12.5. Contractor's Soft Costs

The calculation of contractor's soft costs is predicated on the concept that these projects will be tendered as a Lump Sum Turnkey project including performance wrap, in which the majority of risk for cost and schedule fall on the selected EPC contractor. To this effect, profits and overheads are calculated on full equipment costs, licensor package costs, and bulk materials. The Contractor's Soft Costs include:

- Profit
- Site permitry and licenses
- Bonds
- Insurance
- Materials and spares
- Vendor representatives
- Construction Equipment and tools
- Construction Management and Administration
- Construction services
- Project Management and Administration (including office costs)
- Contractor's contingency (5-10% depending on amount of licensor/vendor responsibility during installation and commissioning)

6.12.6. Owner's Soft Costs

Owner's Soft Costs are applied as a percentage of equipment, material, fabrication and installation costs, with the former being applied to areas in which the equipment provider is responsible for the majority of the equipment supply and installation, and the contractor is responsible for procurement. The owners costs include:

- Environmental/Regulatory Permitting, Site Permitry Oversight, Licensing (Excl. Technology license)
- Legal Costs
- Project Management Oversight and Administration
- Owner's Engineers and Operators
- Insurance
- Third Party Verification / HSSE
- Owner's Expenses

Details of these calculations are limited by confidentiality agreements with prior projects.

6.13. Operating Cost Estimate Summary

Table 6-4 - OPEX Estimate Summary

Option	Total annual OPEX
Compression Case 1, 2 x 50% (0.6 barg) IG Compressor	£25,565,933
Compression Case 2, 2 x 50% (2 barg) IG Compressor	£23,365,747
Compression Case 3, 2 x 50% (3 barg) IG Compressor	£20,713,315
Compression Case 4, 1 x 100% (0.6 barg) IG Compressor	£25,381,078
Dehydration, Molecular Sieve Adsorption	£2,439,633
Dehydration, Silica Gel Adsorption	£828,643
Dehydration, TEG	£757,820
Dehydration, TEG Alternative	£741,497

7. Technology Assessment

7.1. Heat of compression

Heat generated during CO_2 compression can be recovered and utilised in other areas of the plant therefore reducing energy consumption of the process. The compression options reviewed have a cooling demand of between 58 MWth and 69 MWth with CO_2 temperatures of up to 139ºC requiring cooling to 37.5ºC or below depending on the available cooling water temperature.

7.1.1. CO_2 Dehydration Unit

The adsorption dehydration options require heat for regeneration of spent beds, which must be heated to 230ºC in the case of silica gel or 290ºC in the case of molecular sieve. The regeneration gas heat demand could not be fully met from the heat of compression as the CO_2 from compression is not sufficiently hot. It could however be utilised for pre-heating the gas stream before being heated to the required regeneration temperature with steam or electricity. An option of using some of the heat of compression for pre-heating the regeneration gas stream was assessed to determine:

- The LP steam saving (and therefore OPEX saving), and
- The difference in CAPEX due to replacement of the Regeneration Steam Heater with a CO_2 heat exchanger.

For the purpose of this study, Case 3 Stage 1 compressor outlet (see section 5.4.1) has been considered at the highest available stream temperature of 139ºC. The stream is pre-cooled by the CO_2 heat exchanger before entering the intercooler. Some of the compression heat is recovered by heating the adsorption regeneration stream instead of the steam heater. The cold stream outlet temperature of 129°C is assumed. Since the Regeneration Electric Heater inlet temperature is 140°C (base case), the size and the cost of the heater is assumed to be the same. The CAPEX variation is due to the bigger CO_2 heat exchanger required, compared to the steam heater. The results are provided in Table 7-1.

Table 7-1 - Adsorption with molecular sieve - with compressor heat recovery

	Base Case	Heat Recovery	% Var
Heat Transfer Surface Area, per unit (m^2)	45 (Regeneration Gas Steam Heater)	433 (CO_2 Heat Exchanger)	
Plant Total CAPEX (%)	100	108	+8%
LP Steam Consumption (MWh/yr)	17,293	0	
Plant Total OPEX (mil GBP/yr)	2.4	2.0	-15%

Based on the analysis above the recovery of heat of compression would deliver an overall benefit with the increased CAPEX achieving less than a three-year simple payback.

7.2. Operating pressure of stripper

The upstream CO_2 capture process has not been finalised yet, including the operating pressure of the CO_2 stripper. Consequently, it has been agreed to assume the following three scenarios for the CO_2 stripper operating pressure. This will allow a comparative assessment of its impact on the compression unit CAPEX, OPEX and footprint.

- 0.6 barg (1.6 bara)
- 2 barg (3 bara)
- 3 barg (4 bara)

A conventional stripper column used in a proprietary amine plant is operated at c.1 barg and at a temperature of around 122 °C. As the stripper pressure increases, so does the operating temperature. As the stripper operating temperature increases, the partial pressure ratio of water to CO_2 (pH_2O/pCO_2) in equilibrium with the solvent solution decreases and results in a decreased stripping vapour requirement. Since the stripping vapour is steam, a higher stripper pressure will result in a lower total reboiler duty.

In addition, an increased stripper pressure will result in a smaller volume of CO_2 flowing inside the stripper column. Therefore, volumetric flowrates of both steam and CO_2 are expected to be lower as a result of increased stripper pressure. The overall vapour flowrate in the stripper column decreases, which consequently results in reduced stripper size.

Compression duty accounts for nearly 10% of the total energy consumption of a CCS process. Raising the stripper's operating pressure means the CO_2 compressor unit inlet stream is at a higher pressure and, consequently, at a lower volumetric flowrate. This results in a lower overall pressure ratio requirement for the compressor and as such reduced energy duty. Figure 7-1 shows that as the stripper pressure increases from 0.6 barg to 3 barg, the specific volume decreases by ~60% and the compression duty falls by nearly 20%. This suggests that a higher stripper operating pressure has advantages in reducing the energy duty both during separation and compression of CO_2.

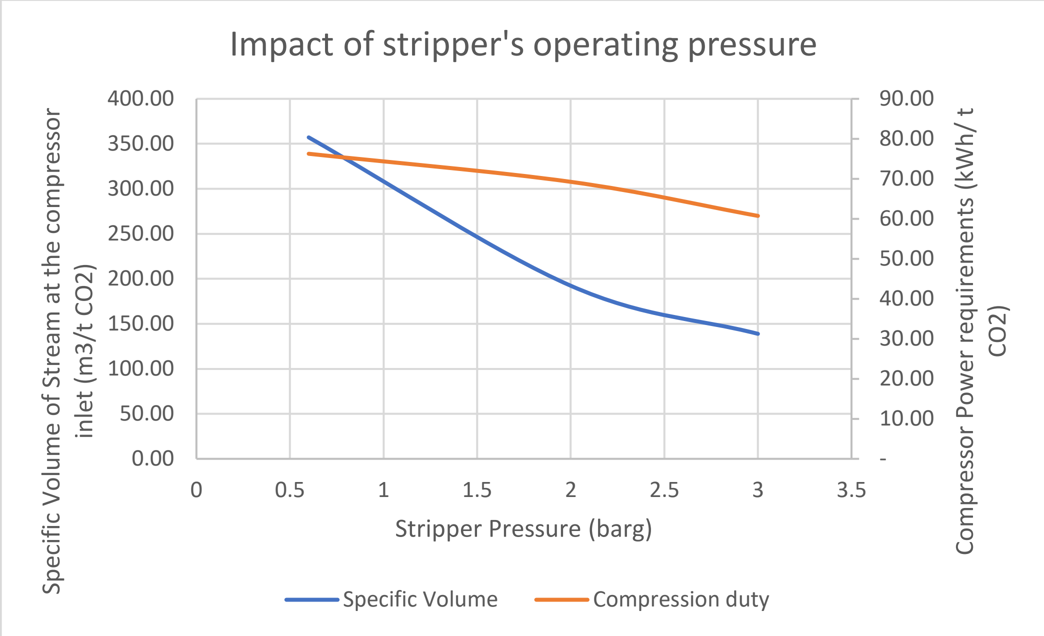


Figure 7-1 - Impact of stripper's operating pressure on the specific volume of the inlet stream and associated power requirements per tonne of CO_2 compressed

In addition, as presented in section 6.12, there is a significant reduction in compressor’s CAPEX when increasing the stripper’s operating pressure. Increased suction pressure leads to the following:

- fewer compression stages (5 compression stages for the 3 barg suction pressure, compared to 6 stages for the 0.6 and 2 barg cases), resulting in
- fewer intercoolers and KO drums, smaller casings and driver, etc., resulting in
- a smaller CO_2 compression unit.

Figure 7-2 presents the effect of the stripper’s operating pressure to the resulting installed CAPEX/OPEX of the compressor units. The CAPEX and OPEX has been taken as a percentage of the costs for the 3 barg stripper pressure.

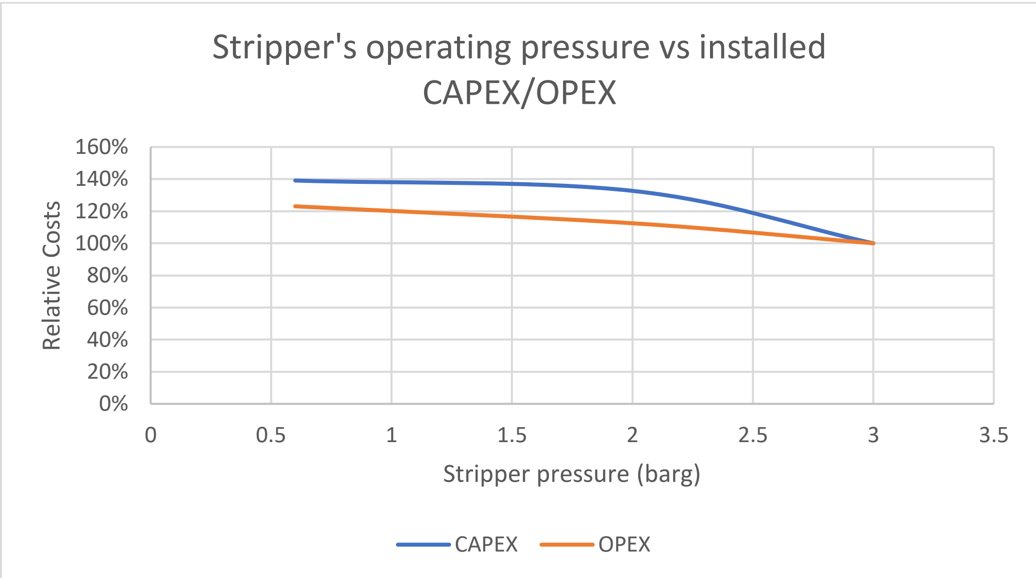


Figure 7-2 - Impact of stripper's operating pressure on the installed CAPEX and OPEX of the compressor unit

Operating the CO_2 stripper at higher operating pressures (therefore increasing suction pressure to the compressor to 3 barg) significantly reduces compressor's CAPEX and OPEX whilst also reducing the capture plant heat demand. Please note, the higher operating pressure may not be favoured for proprietary amine capture technology due to degradation issues (occur at around 135°C), and a potential drawback could be that as the stripper pressure increases, solvent losses due to thermal degradation of absorbents increase as well.

7.3. CO_2 Discharge Temperature

As seen in section 5.3.1, a CO_2 discharge temperature of 45°C was used for the modelling of the compression process. However, National Grid specifications state that a lower discharge temperature (20°C) needs to be achieved prior to entering the CO_2 transport pipeline. As such, the following steps are required to cool the CO_2 stream down to 20°C:

- Step 1: Use of an upgraded aftercooler to cool the CO_2 down to the lowest possible temperature using the available cooling water (27°C). The lowest temperature that could be reached was 36°C.
- Step 2: Use of a chiller facility to cool the CO_2 down from 36°C to 20°C. This would also require an additional aftercooler. There are two options for the chiller facility:
    - Option A: Use of an absorption chiller that could utilise heat from various sources, such as flue gas heat recovery, or heat of compression. Or,
    - Option B: Use of a vapour compression (VC) chiller facility to cool the CO_2 down from 36°C to 20°C.

Table 7-2 presents the additional total installed costs of the above options for compression case 1

Table 7-2 - Additional costs to cool the CO_2 down to 20°C prior to National Grid's pipeline inlet

Process description	**CO_2 Discharge Temperature**	**Delta Costs (£)**
Step 1: Upgraded Aftercooler	36°C	267,764
Step 2 – Option A: Absorption chiller	20°C	9,946,962
Step 2 – Option B: VC Chiller	20°C	2,615,381

7.4. Compressor drives

The compressors can be driven with electrical, gas turbine or steam turbine drives. The three drive types were considered in the study and enquiries made with manufacturers. This identified that the three drive types have significantly different costs with electrical being the lowest cost and gas turbines the highest. Comparative costs are presented in Figure 7-3 with all costs presented as a percentage of the GT package for the 2 x 50% train arrangement.

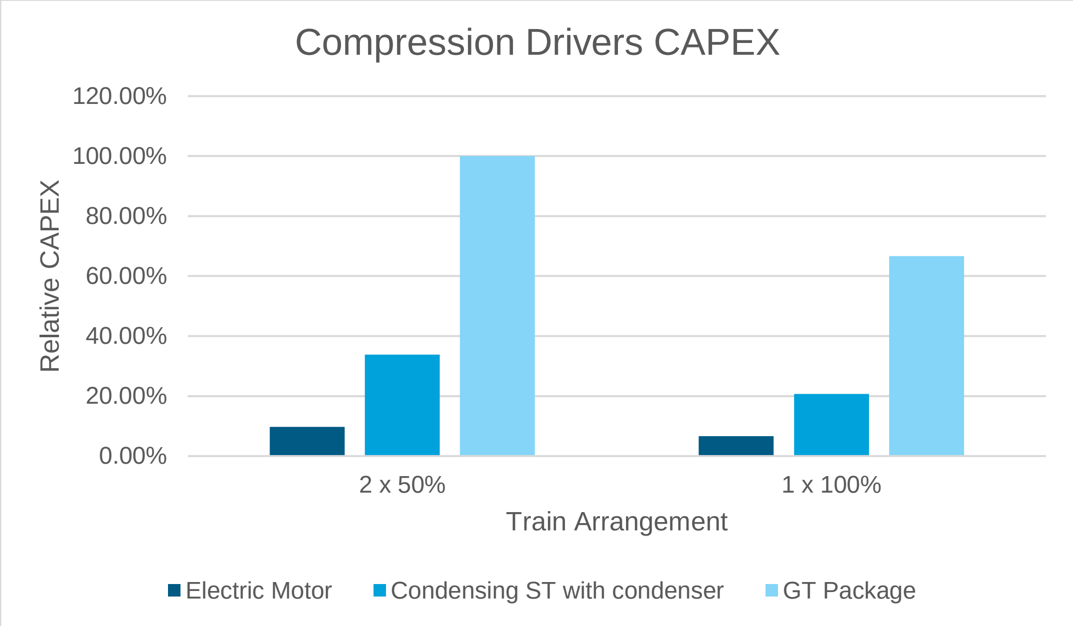


Figure 7-3 - Comparison of CAPEX for three compression drivers, as quoted by a vendor

The key differences between the drivers are:

1. The use of steam or gas turbine drives would add complexity to the start up and operation of the capture plant as the CHP unit would be tightly integrated to the capture process.
2. The use of steam or gas turbines would add complexity to the layout as the CHP and compression plant layout would need to be coordinated.
3. The use of steam or gas turbines would have the potential to deliver energy savings of the order of 10-15% as mechanical power does not need to be converted to electrical power and back again.
4. The steam and gas turbine options are relatively high CAPEX.

Based on the above electrical drives were selected as the preferred option to reduce CAPEX.

7.5. Construction availability assessment

7.5.1. CO_2 Compression Unit

Both types of centrifugal compressors considered in this report – integrally geared and in line – are proven in operational environment with considerable experience in both natural gas industry and CCS (TRL 9). Table 7-3 summarises the experience at existing large scale operational CCS facilities.

Table 7-3 - Large scale CCS project and compression technology used

Project	CO_2 Compression Technology	Capacity	Suction pressure (barg)	Discharge Pressure (barg)
Boundary Dam	8-stage Integrally geared	1.2 mtpa	0.7	190
Rhourde Nouss	5-stage in- line centrifugal	0.5 mtpa	0.4	207
Gorgon Project (LNG)	4 stage in-line centrifugal	6 mtpa (6 trains of c.1 mtpa each)	0.8	216

Petra Nova	8-stage Integrally geared	1.4 mtpa	0.6	131
Port Arthur Hydrogen Project	8-stage Integrally geared	1 mtpa	0.07	156
Quest Oil Sands Project	8-stage Integrally geared	1.2 mtpa	1.5	145
Great Plains Synfuels Plant	8-stage Integrally geared	3 mtpa (3 trains of c.1 mtpa each)	0.1	186

There is a vast availability of integrally geared compressors in the market at the moment. All vendors contacted have confirmed they are able to provide an integrally geared multistage compressor for this application. Delivery period based on current workload and lead times varies for each vendor, but for all was between 14-18 months including workshop testing.

It should be noted that only one vendor offered an in line centrifugal compressor unit for the BECCS project. This could potentially pose a risk when it comes to procurement routes, if the in line is the preferred option.

7.5.2. CO_2 Dehydration Unit

Both dehydration technologies considered in the report, adsorption and absorption, are proven in operational environment (TRL 9) with experience in both natural gas industry and CCS. Table 7-4 summarises the experience at existing large scale operational CCS facilities. However, the table also helps to illustrate the limited experience at the CO_2 capacity of 4 mtpa required for this project.

Table 7-4 - CO_2 dehydration technologies utilised at existing large scale CCS facilities

Project	CO_2 Dehydration Technology	Capacity
Boundary Dam	Adsorption – Activated Alumina	1.2 mtpa
Rhourde Nouss	Absorption – TEG	0.5 mtpa
Petra Nova	Absorption – TEG	1.4 mtpa
Port Arthur Project	Absorption – TEG	1 mtpa
Quest Project	Absorption – TEG	1.2 mtpa
In Salah Gas Plant	Absorption – TEG	1 mtpa

Since the dehydration technologies are established in the market, there are a number of technology suppliers offering the type of equipment required. It is considered to be unlikely for the suppliers not to be able to provide the equipment in accordance with the planned construction program.

7.6. Contaminants impact

The stream of CO_2 from the CO_2 capture unit is not pure CO_2 and will contain some impurities. The presence of impurities has an impact on the phase envelope and also on the properties of CO_2 including density and water content. The impact is particularly noticeable around its critical point. Hence, it is recommended that a review of the properties of CO_2 is undertaken during FEED. This should include:

- Verify water content using Promax and Aqualibrium
- Verify equation of state and review against latest literature e.g. NIST, Span and Wagner

The outcome of the review (concerning properties of CO_2) is unlikely to impact upon the technology selection process to be undertaken prior to FEED.

One of the recommendations made by Atkins during Stage 1 was to review the oxygen and ammonia content during Stage 2. NGC specify ≤ 10 ppmv of oxygen [4] and is the required level set to maintain the integrity of well bore materials. C-Capture provided a list of contaminants [2] and have noted the required levels of oxygen and ammonia. C-Capture confirmed there is no ammonia present and the amount of oxygen has yet to be confirmed. If necessary, the oxygen content can be reduced using additional CO_2 conditioning equipment downstream of the CO_2 capture unit. This will be reviewed once the amount of oxygen has been confirmed.

C-Capture have provided levels of impurities taken from accelerated ageing tests and the expected ranges following water wash. The targeted level of VOCs is reported to be 1 ppb. However, it might be necessary to consider the unabated level of 2000 mg/m3 during upset conditions as part of dispersion modelling to be undertaken during FEED.

The proprietary capture solvent used by C-Capture has a targeted value of 1 ppb therefore is unlikely to cause issues with the molecular sieve beds.

During regeneration when liquid water is formed acids may form due to the presence of CO_2, NOx and SOx. The resultant acidification will shorten the bed life of the molecular sieves although this can be minimised by using a combined system e.g. alumina bed above the molecular sieve bed.

If a proprietary amine is selected for the capture of CO_2; the amine may adsorb on the molecular sieve bed causing permanent damage. Again, this can be minimised by using a combined system e.g. silica gel above the molecular sieve bed.

Absorption processes using TEG are less susceptible to impurities than desiccant beds. One of the vendors has confirmed that the presence of some contaminants such as VOC or sulphur compounds can be handled in the TEG unit without any issues as long as the necessary design provisions have been made. However, oxygen can lead to glycol degradation although this is not expected to be an issue at the specified level of oxygen of 10 ppmv.

7.7. Flexible operation including capacity control and single train vs. 2 x 50% trains – Turndown modelling.

It is recognised that the BECCS power plant will require a high degree of operating flexibility to operate in the electricity market, responding to the peaks and troughs of daily electricity demand. This requirement is likely to become even more important as greater levels of renewables come on line. Hence, the turndown capability of the CO_2 compression and dehydration facilities is crucial to the successful operation of the plant.

A turndown ratio on the boiler output of at least 50% and preferably 33% is required.

Table 7-5 - Summary of turndown capabilities of selected units

Plant unit and train arrangement	Turndown to
Compression unit (1 x 100%) – use of IGVs	75 - 100%
Compression unit (1 x 100%) - Recirculation	0 - 100%
Compression unit (2 x 50%) – use of IGVs	37.5 – 50% and 75 – 100%
Compression unit (2 x 50%) - Recirculation	0 - 100%
Dehydration unit (1 x 100%)	30 - 100%
Dehydration unit (2 x 50%)	15 - 100%

As discussed in Section 5.4.4.2, integrally geared compressors present a turndown capability of 20-30%, depending on the vendor selected. This means that the compressor is able to operate at 70-80% part-load by utilising the existing IGVs installed before each stage. The installation of two parallel compressor trains results in higher flexibility, making it possible to achieve operation at the range of 35-50% load by simply switching off one of the trains. However, a two-train arrangement presents approximately 1.7 times higher cost compared to the one train arrangement. OPEX is also increased for the two trains case, however, the difference is marginal and stems mainly from the maintenance and spares costs. For further turndown, gas recirculation will be required resulting in a less efficient process. As such the minimum load of 33% advised by Drax, is probably going to require some gas recirculation bleed.

The dehydration unit does not present any issues with part load operations. Specifically, one 100% unit can operate as low as 30% part loads, while when using 2 x 50% trains 15% part load operation is possible by just switching off one of the units.

7.8. Reliability, Availability and Maintenance assessment (2 x 50% trains)

Table 7-6 summarises the reliability, availability and maintenance values for the total plant including the CO_2 compression and dehydration units.

Table 7-6 - Summary of availability, reliability figures and maintenance schedules

Unit	Reliability	Availability	Maintenance
CO_2 Compression Unit	99.5%	99%	Annually: Level 1 routine inspections (on-line, no dismantling) Year 2-3: Level 1 minor inspections (on-line, no dismantling) Year 5-6: Level 2 minor inspections (with downtime) Year 10: Preventive maintenance (machine disassembly, significant downtime)
CO_2 Dehydration Unit	Not reported	>98.5%	Absorption: During planned shutdowns, it is recommended to check internals of the columns and the reboiler and to clean them if necessary. Adsorption: During planned shutdowns, spent desiccant to be replaced.
Total		>97.5%	Dehydration and Compression plant combined.

The range of availability stated above does not consider the 2x50% train configurations which would provide an increased availability for at least 50% of the capacity. It should be noted however that the availability figures above are based on typical data for similar complete plants so include BOP. Redundancy for heat/steam raising capacity has not been considered in the scope of this study.

8. Conclusions

Compression

The stage 2 study has identified that:

- Integrally geared and inline compression technologies provide viable options for the required CO_2 compression duty. However, integrally geared compressors are the favoured technology and offer savings in CAPEX, OPEX (following optimisation), efficiency and footprint. Both types of compressors offer the same high reliability and availability of around 97.5%.
- For the 1 x 100% capacity one vendor had a preference for inline machines due to limitations in the power capacity for the drive gear.
- The compressor + pump case presented 2.5-4% lower OPEX compared to the compression only case. However, this OPEX reduction is considered marginal compared to the 20% increase in CAPEX.
- Higher stripper operating pressures significantly reduces compressor's CAPEX and OPEX whilst also reducing the capture plant heat demand.
- Electrical drives for compressors present low CAPEX.
- Both 1 x 100% and 2 x 50% train arrangements provide viable options and are available products from vendors. However, there is no evidence of 100% trains (~4mtpa) therefore presenting additional risk to the project.
- A 2 x 50% train arrangement presents ~1.7 times higher CAPEX, compared to a single train configuration
- A 2 x 50% train arrangement offers significant OPEX advantages over 1 x 100% configuration if turndown below 50% is required for significant periods of time, since lower levels of gas recirculation are required.
- The compressed CO_2 discharge stream cannot be cooled down to 20°C with the current cooling water available on site. An additional chiller facility will be required, resulting in an increase in TIC.

Dehydration

The stage 2 study has identified that:

- All three CO_2 dehydration technologies (silica gel, molecular sieve and TEG) provide viable options for the required CO_2 capacity and are available products from a range of vendors.
- All three CO_2 dehydration technologies (silica gel, molecular sieve and TEG) offer high availability (above 98%) and can achieve the required minimum turndown of 33%.
- The three CO_2 dehydration processes offer roughly the same CAPEX. Absorption with TEG indicates the highest total CAPEX with the lowest OPEX per year. Adsorption with silica gel indicates the lowest CAPEX with a higher annual OPEX.
- The OPEX is based on LP steam and additional electrical heating. The study shows this as an economic option reducing OPEX per year (in the case of molecular sieve). The resultant simple payback is less than one-year for adsorption with molecular sieve; for other options it may be up to three years.
- Adsorption with molecular sieve can offer the lowest product moisture content of 1 ppmv but requires significant heat and power and thus the highest annual OPEX. This option will potentially allow for other emitters in the industrial hub to blend streams with moisture content of above 50 ppmv. However, the CO_2 transport network would then be fully reliant on the Drax CCS plant being operational to allow other users to discharge wetter CO_2 streams. This would then require the Drax CCS plant to operate with very high reliability and availability.
- The CAPEX for molecular sieve option is comparable to the other two technologies.
- The option of recovering some of the heat of compression in the spent bed regeneration process would deliver an overall benefit with the increased CAPEX achieving less than a three-year simple payback.
- Absorption processes using TEG are less susceptible to impurities than desiccant beds.
- Since the dehydration technologies are established in the market (TRL 9), there is a number of technology suppliers offering the type of equipment required. It is considered to be unlikely for the suppliers not to be able to provide the equipment in accordance with the planned construction program

- TEG units are often preferred by the CO_2 compressor vendors, due to their robustness against pressure ramps which can be seen at start-up and shutdown procedures. In comparison, an adsorption package will need to be completely isolated from the compressor for shutdown and start-up, as pressure ramps are not acceptable to the drier bed.

9. Recommendations

Overall

- Financial modelling of the options to establish preferred options
- Confirm likely durations for operation of the Drax unit below 50% load to assist in option selection between 2 x 50% and 1 x 100% options. This should be then specified within a user requirement specification for the Pre-FEED study to enable value engineering to establish if investment in multiple units is justified to achieve turndown. The increased CAPEX of multiple trains being balanced against OPEX benefits.
- Carry out RAM analysis for the various plant options to establish appropriate levels of redundancy achieve the desired availability. Initially this should be done at a high level to allow redundancy levels for major plant items and key utilities and BOP items to be specified.
- Higher stripper operating pressure (3 barg) should be further explored as it presents significant advantages over low pressure operation (0.6 - 2 barg) for both the CO_2 capture and compression stages.
- Additional heat integration to further utilise heat of compression should be investigated.
- Dedicated study work to establish CO_2 physical properties based on actual impurities expected from Drax unit/capture technology.
- Specific study to consider CO_2 dispersion under credible loss of containment scenarios to establish appropriate separation distances from populated areas/buildings or other risk mitigations such as access controlled zones for this project.

Compression

- Atkins are not aware of operating experience for a CCS compression duty in 1 x 100% configuration (although vendors have quoted machines for ~4 mtpa CO_2); Therefore, Atkins recommends 2 x 50% machines so that there is confidence in design and operation at the required duty. However, the 1 x 100% configuration should not be ruled out for the increased suction pressure (3 barg), due to the lower volumetric flowrates at the compressor inlet for this case, which would be similar to a 2mtpa for an amine capture process..
- There is a preference for integrally geared machines for both train arrangements. However, vendors can offer inline machines for the 1 x 100% case if integrally geared compressors are not bankable at this power.
- Further study shall be carried out to establish if 2 x 50% or 1 x 100% compression trains are preferred based on economic modelling that considers the annual duration where turndown below 50% is required. This recommendation is made as there is significant additional CAPEX investment required for the 2 x 50% configuration to deliver an improved OPEX over the turndown range.
- Should C-Capture technology be utilised for the project then operation of the stripper at 3 barg is recommended as this lowers the overall CAPEX and OPEX for the compression train. This also indicates that higher stripper operating pressures are preferred for other capture technologies, although it should be noted a pressure of 3 barg may not be favoured for proprietary amine capture technology due to degradation issues.
- When specifying the plant, vendors should be allowed to offer either integrally geared or inline machines if single 1 x 100% train configuration is progressed. Although a preference for integrally geared can be expressed, especially for the 2 x 50% trains.
- Compression + pump configuration shall not be taken forward due to ~20% increased CAPEX, higher maintenance costs, added complexity and 40-60% larger footprint.
- Electric drivers are recommended for the compressors. Electric drivers present lower CAPEX and higher availability and avoid complex integration of a CHP and compression trains.
- During FEED verify equation of state used by suppliers and by FEED/EPC contractor for all process design simulations (refer to HAZID/ENVID).

Dehydration

- Carry forward both absorption and adsorption dehydration technologies to the next stage for a more detailed design and cost assessment. Silica Gel and TEG are preferred if significant value cannot be gained for the lower CO_2 water content (obtained via molecular sieves) from the transportation operator.
- Utilise heat of compression recovery as far as possible for regeneration heat adsorption technologies.

10. References

[1] Drax Corporate Limited, Functional Specification for Optimal CO2 Compression at Drax Power Station, Selby: Drax Corporate Limited, 2019.

[2] C-Capture, “Process Design Development, Process Flow Diagram, Rev 0,” Leeds, UK, 2019.

[3] R. Dittmer and R. Strube, “Integrally-geared compressors as state-of-the-art technology,” *Carbon capture journal* , pp. 15-18, September - October 2015.

[4] National Grid Carbon, “NGC/SP/PIP/25 National Grid Carbon Specification for Carbon Dioxide Quality,” 2014.

[5] IEAGHG, “Evaluation and analysis of the performance of dehydration units for CO2 capture,” 2014.

[6] Atkins, “5191168-REP-003 Rev A1, Stage 1 Preliminary Design Report,” 2019.

[7] Atkins, “5191168-TCN-039 Heat Recovery Technical Note,” 2020.

Appendix A. HAZID/ENVID

Project Number		5191168	**Project Title:**		5191168 - Drax BECCS CO2 Compression and Dehydration Feasibility						**Initial Impact / Likelihood**			
Review Date		25/10/2019	**Attendees (Initials)**		TJ, KK						**Health and Safety**	**Environment**	**Financial**	**Likelihood**
Reference:														
Line No	**Key Word**	**HAZARD**	**Consequence**	**Safeguard / Protection**	**Action / Comments**	**Action ID**	**Actionee**	**Action Due Date**	**Owner (s)**	**Status**				
Section A; External and Environmental hazards														
1	**Natural and Environmental Hazards**	*Wind and dust/snow loading*	Could cause failure of pipework and vessels. Release of inventory; Glycol, CO2, chemicals. Air intake blockage due to dust. Potential structural collapse resulting in injury or death of people in the locality.		Eurocode 3 to be used for structural design. Wind speed and pressure considered in BEDD (section 4), 50m/s design speed and current design allows for >70m/s for vessels, pipework and structures.	A1	FEED CONTRACTOR				5	3	5	D
2	**Natural and Environmental Hazards**	*Lightning*	Cause shorts in motors/ electrical equipment. Equipment failure, fire risk.	Design must consider lightning cases for earthing design in line with relevant standards	FEED Design contractor to consider during FEED.	A2	FEED CONTRACTOR		DCL		4	3	3	E
3	**Natural and Environmental Hazards**	*Extremes in temperature*	Burst water pipes, damage. Falling ice, personnel protection from touch, impact (falling objects)..		Insulation and trace heating requirements to be addressed in FEED design. Materials of construction to consider low temperature brittle fracture, including JT cooling effects on depressurisation.	A3	FEED CONTRACTOR				3	2	2	D
4	**Natural and Environmental Hazards**	*Flooding*	Plant shutdown. Chemicals / oil inventory escape. Environmental contamination.		Project to review flood risk and installed preventation methods for selected site.	A4	FEED CONTRACTOR				2	4	3	E
5	**Created (Man made Hazards)**	*Road traffic in poor layout*	Vehicle impact of existing or new site traffic. Requirement for access Capture plant for delivery of chemicals etc.	DPL have bollards on access routes to help mitigate on existing transport routes	Vehicle protection needed for new assets or any existing assets that become more exposed due to revised layout/traffic routing. Consider plot layout for Ease of access for HGVs or mobile plant required for maintenance. Plan for chemical delivery lorries drive in drive out (no reversing).	A5	FEED CONTRACTOR				4	3	4	D
6	**Created (Man made Hazards)**	*Chemical Spills, unintentional fill/empty human error*	Chemical spill potential within fill/ empty tanker area. Environmental impact and potential risk to personal health.		Tanker unloading area 'bunding', barrier and drainage to segregated sump capable of containing maximum spill volume. If necessary consider vapour return lines or treatment of tank vapours from breather vents.	A6	FEED CONTRACTOR				2	2	2	C
7	**Created (Man made Hazards)**	*Chemical Spills, unintentional fill/empty human error*	Chemical spill potential from storage on site tanks. Environmental impact and potential risk to personal health.		Tanks to be designed to relevant codes and have 110% bunds to prevent environmental release if ruptured.	A7	FEED CONTRACTOR				3	3	2	D
8	**Created (Man made Hazards)**	*Chemical Spills, unintentional fill/empty human error*	Increased risk of chemical spills with higher frequency of tanker fills &and waste removal. Risk to environment and personnel health.		Designer to confirm optimisation of frequency of chemical fill by tanker. Or removal of waste. Include consideration of larger containers.	A8	FEED CONTRACTOR				2	2	3	C
9	**Created (Man made Hazards)**	*Vehicle impact*	During lifting operations, crane impact on existing overhead structures (and critical plant).	Site expected to be free from overhead obstructions. But neighbouring coal and biomass conveyors to be considered as height restrictions for bringing large plant to site.	Constructability review required to ensure that optimum craneage costs and recognition of surrounding obstructions are taken into account including confirming access for large items.	A9	FEED CONTRACTOR				4	1	5	A
10	**Created (Man made Hazards)**	*Mal-operation of plant because of division between power gen / oil & gas cultures*	Damage to plant. Accident.	Engagement with National Grid Carbon and Equinor from early stage of project.	During FEED develop full chain deliverables to reduce risk associated with integration of the full chain. Deliverables to include: Operations and maintenance philosophy; Basis of Design;	A10	FEED CONTRACTOR				4	3	4	D
11	**Created (Man made Hazards)**	*Terrorist attack or cyber attack*	Fatalities, plant damage, loss of power generation, software / control damage	Site a site of nationally important infrastructure with relevant standards met for physicla and cyber security.	Ensure external data links if necessary for new plant are understood and controlled. Control and vetting of contractors during construction.	A11	DCL				5	4	5	E
12	**Effect of the facility on surroundings**	*Road Traffic*	Disruption to local operations during construction phase (e.g. roadways, access to neighbouring processes or the construction area).		Constructability review to consider interaction between construction and operational activities.	A12	FEED CONTRACTOR				2	1	2	A

Project Number		5191168	**Project Title:**		5191168 - Drax BECCS CO2 Compression and Dehydration Feasibility						**Initial Impact / Likelihood**			
Review Date		25/10/2019	**Attendees (Initials)**		TJ, KK						**Health and Safety**	**Environment**	**Financial**	**Likelihood**
Reference:														
Line No	**Key Word**	**HAZARD**	**Consequence**	**Safeguard / Protection**	**Action / Comments**	**Action ID**	**Actionee**	**Action Due Date**	**Owner (s)**	**Status**				
13	**Effect of the facility on surroundings**	*Noise*	Noise impact to locals & site operation staff in nearby proximity to carbon capture plant. Potential hearing damage to people in locality of plant.		DCL to noise limits for general operational areas to be specified. High noise levels from plant to be identified by designers and attenuation requirements to be identifed.	A13	DCL/FEED CONTRACTOR				2	1	1	B
14	**Effect of the facility on surroundings**	*Glycol Release*	Release of glycol to atmosphere if TEG dehydration used resulting in impact to the environment.	Consider during technology review	Design of dehydration unit to minimise carryover of TEG to atmosphere	A14	FEED CONTRACTOR				1	2	2	C
15	**Infrastructure**	*Blocking access routes*	Lack of laydown area impacts on plant operations or construction productivity.		Provision of Laydown, construction area to be agreed.	A15	DCL				3	1	2	B
16	**Infrastructure**	*Unknown undergrounds*	Existing buried services breach of known or unknown lines		GPR and survey work to be undertaken during FEED to supplement existing records as required.	A16	DCL				3	3	2	C
17	**Infrastructure**	*Dehydration media*	Environmental impact & risk to personnel safety during replacement of dehydration media. Potential impacts to health from long term exposure to dust (if mole sieve). Could be caused by skin contact, inhalation or ingestion.	Longer life media selected Media contained in process except for during media replacement.	Design of dehydration units to facilitate replacing media without enviromental release. Select media that presents lower or no hazard.	A17	FEED CONTRACTOR				4	2	1	C
Section B; Health Hazards														
18	**Health Hazards**	*Flue gas leak from near by ducts/plant.*	Asphyxiation risk to personnel, fabric jointing potential to fail. High temperature flue gas has localised potential to cause burns.	Open air and routing expected to be at height. Low or potentially negetive duct pressure depending on leak location along duct and operating condition. Separation between compression/dehydration plant and flue gas ducts.	NA	B1	FEED CONTRACTOR				4	0	0	D
19	**Health Hazards**	*High temp operation*	Burns, risk to personnel (touch or close proximity)		Insulation or guarding of hot components to be considered by designer.	B2	FEED CONTRACTOR				2	0	0	A
20	**Health Hazards**	*Electrocution*	Switchgear, transformer pen access and risk to site personnel.	Design to relevant standards/reguations (Wiring regs., Buildings regs etc) and Drax site standards.	Consideration of access control to HV/LV equipment under DPL safety rules. E.g. If requirement for gated access Ensure competency of designers.	B3	FEED CONTRACTOR				4	0	0	B
21	**Health Hazards**	*Working at height*	Maintenance/operation or access to higher modules, risk to personnel and impact to escape routes.	Compliance with relevant regulation (e.g CDM regs, Working at Height Regs., PUWER etc.)	Provision of stairs/ ladders to be considered dependant on frequency of maintenance. Ergonomics for operation to be considered in design.	B4	FEED CONTRACTOR				4	0	0	C
Section C; Project Implementation Issues														
22	**Contracting Strategy**	*Contractor appointment*	Risk to project that contractors are suitable competent	Drax contracting proceedures, informed client practiced in appointing contractors to undertake new build projects.	Contractor selection criteria should be developed to asess contractors against key competencies. In major project construction, complex process integration, Carbon Capture plant design, UK regulations etc	C1	DCL				5	5	5	D
24	**Control Methods Philosophy**	*Voltage dips*	Start-up of motors can cause voltage dip on system, potential trip, instability. Potential for unsafe plant condition to result.		Soft start or inverter drives to be considered for drives	C2	FEED CONTRACTOR				4	2	4	D
Section D; Facility Hazards														
25	**Layout**	*Constrained site*	Restricted access, complex construction		Layout to be developed at FEED to consider maintenance and & constructability.	D1	FEED CONTRACTOR				3	1	3	C
26	**Fire and Explosion Hazards**	*Lube Oil Mist*	Compressor lube oil system operates at high pressure with potential to create mist if leaks develop. Oil mist could ignite if it reaches an igntion source leading to fire and explosion with potential fatalities, injury and asset damage.	Compliance with API 614 is basis of compressor designs offered by major suppliers.	Consider in lube oil console design – inerting / venting arrangements	D2	FEED CONTRACTOR				5	2	5	D

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Reference:														
Line No	**Key Word**	**HAZARD**	**Consequence**	**Safeguard / Protection**	**Action / Comments**	**Action ID**	**Actionee**	**Action Due Date**	**Owner (s)**	**Status**				
27	**Process Hazards**	*CO2 leading to Asphyxiation*	CO2 is toxic and an asphyxiant at concentrations of ~15% (150,000 ppm) or higher (HSE). CO2 is an odorless gas and about 1.5 times as heavy as air. Since it is denser than air, high concentrations can occur in open pits and other areas below grade. The CO2 will be processed with significant inventories at high pressure. Vessel or line rupture could lead to large release and toxic atmosphere/asphyxiation. HP CO2 release potential for multiple fatalities in dense gas cloud.	Normally unmanned operation – ie. Separate people and hazards. Compliance with PER Seal designs to API Process safety management for project inline with IEC 61508. Safe Engineering Practice – e.g. HAZOP	Apply lessons learnt from other CCS projects. Pressure vessel and piping designs to be in accordance with relevant standards and for regulatory compliance. Sectionalisation of pipelines and process to control inventory sizes. Develop vent and blowdown philosophy. Dispersion calculations and design of vents to feed into layout.	D3	FEED CONTRACTOR				5	1	2	C
28	**Layout / separation distances**	*CO2 leading to Asphyxiation*	CO2 is toxic and an asphyxiant at concentrations of ~15% (150,000 ppm) or higher (HSE). CO2 is an odorless gas and about 1.5 times as heavy as air. Vessel or line rupture could lead to large release and toxic atmosphere/asphyxiation. It is heavier than air and could sink into voids and existing pipe/cabe tunnels. This could pose a risk of asphyxiation to people distant from the release. CO2 is not currently defined as a dangerous substance under the Control of Major Accident Hazards Regulations 1999 (COMAH) or as a dangerous fluid under the Pipelines Safety Regulations 1996 (PSR) reliance on regulations alone maybe insufficient. HP CO2 release potential for multiple fatalities in dense gas cloud.	Complience with relevant regulations to control risks e.g. CDM, PER, PSR PSSR etc. Existing access controls Drax apply to access to tunnels. Separation in accordance with SNC-Lavalin standards, GAP and PIP standards. Checked against dispersion models and QRA.	CO2 should be treated as toxic for the basis of development of separation distances. Accurate dispersion calculations based on developed design and layout. Aim to eliminate impact by selecting site with no neighbours in dispersion zone. Understanding the dispersion should drive the layout to make it safest for the specific location. Layout of plant to be considered to create separation from existing tunnels, pits, low points and trenches. Where low points can't be eliminated in design access should be controlled through locked manways, grills and hatches. Entry controlled by confined space entry permits. Consider separation distances during site selection / layout review. Consider refuges and safe havens during layout review. Consider CO2 gas detection in pipe and cable tunnel that could transport CO2 to distant plant locations. Consider location of control room.	D4	DCL/FEED CONTRACTOR				5	2	3	D
29	**CO2 Pipeline**	*CO2 leading to Asphyxiation*	CO2 is toxic and an asphyxiant at concentrations of ~15% (150,000 ppm) or higher (HSE). CO2 is an odorless gas and about 1.5 times as heavy as air. Failure of CO2 pipeline (such as rupture)could pose a risk of asphyxiation and potential loss of life.	Normally unmanned operation – ie. Separate people and hazards. Compliance with PER Process safety management for project inline with IEC 61508. Compliance with PD 8010, includes separation distance requirements etc.	Project to review CO2 pipeline routing to ensure it is routed away from built up areas and plant. Review export pressure in pipeline against a lower pressure with downstream boosting at shoreline. Consider ALARP.	D5	FEED CONTRACTOR				5	2	3	D
30	**Process Hazards**	*CO2 leading to Asphyxiation*	CO2 is toxic and an asphyxiant at concentrations of ~15% (150,000 ppm) or higher (HSE). CO2 is an odorless gas and about 1.5 times as heavy as air. Failure of CO2 pipeline (such as rupture) and HP sections of CO2 piping / equipment could pose a risk of asphyxiation and potential loss of life. Lack of precedence causing uncertainty within project team of HSE requirements. HP CO2 release potential for multiple fatalities in dense gas cloud.	Normally unmanned operation – ie. Separate people and hazards. Compliance with PER Process safety management for project inline with IEC 61508. Compliance with PD 8010, includes separation distance requirements etc.	Dispersion modelling to apply lessons learnt from DF1 to ensure accurate modelling of CO2 releases - planned and unplanned. Consider additional isolation and reduce inventory. Consider level of protection for any manned areas. When developing site specific layout ensure CO2 hazard area is positioned away from people on and off site. Building risk assessment to be carried out as part of QRA activities. Provide monitoring and means of escape to safety e.g. PPE / 10 min escape sets similar to H2S detection escapes. Adequate detection equipment. Avoid pits and low points in design - include gas monitoring in those that cannot be avoided. Personal gas monitors for operators, areas and buildings. Review CO2 detector technology.	D6	FEED CONTRACTOR				5	2	3	D
31	**Process Hazards**	*CO2 leading to Asphyxiation*	J-T leads to cold CO2. Potential to block vent with dry ice. Missiles of dry ice causing damage to piping, equipment and structures. Personnel injury. HP CO2 release potential for multiple fatalities in dense gas cloud.	Experience of real life projects - apply lessons learnt. Adequate design of CO2 dehydration to ensure CO2 is dry. Stainless steel to be used for CO2 compressor and dehydration equipment.	Check design is adequate for safe venting. Determine zone of cold hazard and perform consequence analysis. Consider mechanical protection in cold hazard areas. Consider additional separation between high pressure CO2 and rest of plant. Carry out HSE assessments on all CO2 vents.	D7	FEED CONTRACTOR				4	1	2	C

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Reference:														
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32	**Process Hazards**	*Design codes not suitable for CO2 leading to loss of containment / accident.*	Detailed standards and codes of practice written specifically for the design and operation of dense phase or supercritical CO2 plant and pipelines are still being developed. General process engineering and pipeline standards exist (such as those for natural gas) may not be sufficient. The HSE acknowledge there are limitations of current knowledge and therefore the current regulations may change if justified by the evidence. This is a key project risk identified in both Longannet and Peterhead risk registers. Changes to regulation that occur late in a design will have a significant impact on schedule and cost.		Apply lessons learnt from other CCS projects such as ensuring correct equation of state is used.	D8	FEED CONTRACTOR				5	2	3	D
33	**Process Hazards**	*Liquid CO2 due to off spec composition*	Change of phase, potential for liquid drop out or solids formation with damage to downstream plant e.g. compressors.	Knock out drums included at compressor suction and after coolers to remove condensed liquids.	Depressurisation cases to be considered in detail at FEED to consider safety relief and deinventorying.	D9	FEED CONTRACTOR				4	2	4	D
34	**Process Hazards**	*Water due to off spec composition*	Water content is grossly over predicted by PR and can result in incorrect specification of dehydration package	Simulations and process design carried out by specialist suppliers of dehydration equipment	During FEED verify water content using Promax and Aqualibrium	D10	FEED CONTRACTOR				2	1	4	C
35	**Process Hazards**	*Design and operation of CO2 facilities*	Incorrect equation of state can result in incorrect specification of CO2 compressor	Simulations and process design carried out by specialist suppliers of CO2 compressors	During FEED verfity equation of state used by suppliers and review against latest literature e.g. NIST, Span and Wagner	D11	FEED CONTRACTOR				2	1	4	C
36	**Process Hazards**	*Design and operation of CO2 facilities*	Impurities from capture plant impact upon performance of CO2 compressor and dehydration facilities	Obtained list of potential impurities from C-Capture and for general amine technology. Reviewed during technology selection phase.	Continue to review and apply lessons learnt from other CCS projects.	D12	FEED CONTRACTOR				2	1	4	C
38	**Maintenance Hazards**	*Isolations*	Unsafe isolation, or inability to isolate.	Drax permit to work procedures would ensure isolations would allow work to proceed safely.	Isolation requirements to align with HSG 253, requirements to be determined at FEED. With consideration of maintenance requirements and lockable valves.	D14	FEED CONTRACTOR				4	2	2	B
40	**Process Hazards**	*Compressors*	High speed rotating plant (centrifugal compressors). Rotating plant risk with possible catastrophic failure resulting in projectiles beyond Compression plant boundary)	Compressors of similar design to previous reference projects and sourced for reputable suppliers. Machinery Safety Regulations Robust coupling guarding (API Standard)	Detailled rotor dynamic analysis to be performed by OEM suppliers to demonstrate machines will operate safely. "rotodynamic" to API Standard Clauses Safe layout practice – i.e. don't put something sensitive perpendicular to coupling	D16	FEED CONTRACTOR				5	2	4	D
41	**Maintenance Hazards**	*Lighting provision & fixing*	inadequate lighting poses operator/maintenance risks.		Lighting provision to be assessed during FEED design	D17	FEED CONTRACTOR				3	0	1	C
43	**Construction/ Existing Facilities**	*Overload of existing structures leading to collapse*	Tie in onto existing structures will increase loading which affects capacity.		To review loading on existing structure with DCL interface. Atkins to provide loads to DCL for assessment	D19	DCL/FEED Contractor				4	1	3	D
45	**Construction/ Existing Facilities**	*Contamination*	Health and environmental impact to exposure to contamination		DCL to sample soil core at site (e.g. asbestos). May be historic record from biomass store project. Contamination to be removed by excavation or excavation to be controlled by permit	D21	DCL/FEED Contractor				3	3	3	C

Risk Scoring classification

PROBABILITY	Very Low 1	Low 2	Medium 3	High 4	Very High 5
A Almost Certain 5	5	10	15	20	25
B Likely 4	4	8	12	16	20
C Possible 3	3	6	9	12	15
D Unlikely 2	2	4	6	8	10
E Rare 1	1	2	3	4	5

IMPACT

- Critical risk
- High risk
- Medium risk
- Low risk
- Negligible risk

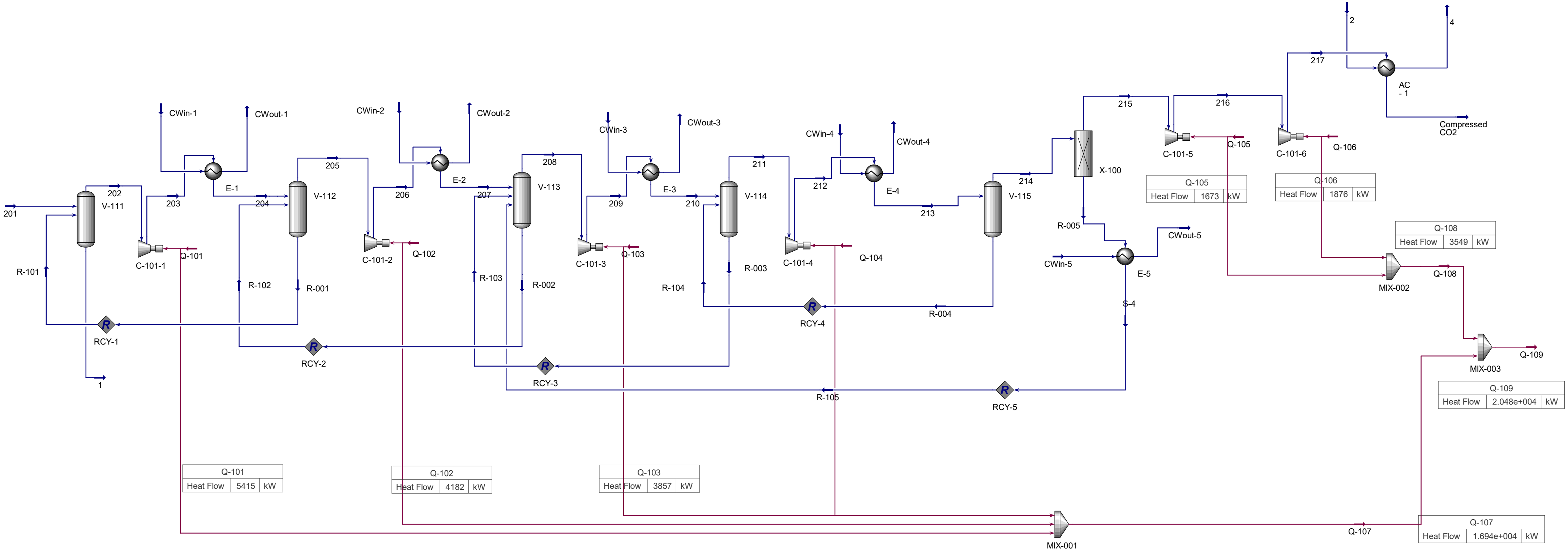
Risk Scoring matrix

IMPACT	1 - Very Low	2 - Low	3 - Medium	4 - High	5 - Very High
Financial %	3 x <1% project cost over the agreed project lifecycle period	3 x 1% project cost over the agreed project lifecycle period	3 x 5% project cost over the agreed project lifecycle period	3 x 10% project cost over the agreed project lifecycle period	3 x 25% project cost over the agreed project lifecycle period
Programme %	1% of the project timescale agreed	2% of the project timescale agreed	5% of the project timescale agreed	10% of the project timescale agreed	25% of the project timescale agreed
Regulatory	Minor regulatory breaches resulting in immaterial fines or minor censure	Regulatory breach resulting in minor fines and short term disruption to the business	Major regulatory breach resulting in moderate fines and short term disruption to the business	Severe regulatory breach resulting in significant fines and/or licence restrictions	Very severe regulatory breach or policy change which leads to high fine, serious censure or loss of license
Health and Safety *	First aid injury	Recordable injury (Worse Than First Aid or Lost Time Incident) or multiple first aid injuries	Reportable Injury (RIDDOR) or multiple recordable injuries	Major injury resulting in permanent impairment or multiple reportable injuries	Fatality or multiple major injuries resulting in permanent impairment
Reputation	No media coverage, small inconvenience with local and/or project stakeholders, BEIS, councils, community and/or interest groups	Limited adverse local or social media coverage, minor local or digital community impact. Limited inconvenience with project stakeholders, BEIS, councils	Regular adverse local media coverage, occasional adverse national media coverage, moderate local and/or digital community impact. Regular Adverse local impact/ inconvenience with project stakeholders, BEIS, councils	Regular adverse national media coverage including criticism or campaigning, major local and digital community impact. Regular Adverse national impact/ inconvenience with project stakeholders, BEIS, councils	Sustained national adverse media and/or social media coverage and opinion former criticism resulting in significant stakeholder concerns or significant impact to customers/ suppliers. Sustained Adverse impact/ inconvenience with project stakeholders, BEIS, councils
Environmental	Inconsequential or no adverse effects	Minor adverse effects, confined to site	Short term adverse effects, local emergency response	Localised, medium term, significant adverse effects. Immediate emergency response	Widespread, long term, significant adverse effects. Major emergency response
Strategy	Minor impact on business unit objective but no impact on overall Group strategy	Major impact on one or more business unit objectives, but no impact on the overall Group strategy	Major impact on one or more business unit objectives, with some impact on Group strategy	Severe impact on the delivery of a Group strategic objective	Group not able to meet multiple strategic objectives

* These definitions include OSHA and RIDDOR criteria for occupational disease and illness

	Over the five year Business Plan period				
PROBABILITY	E - Rare	D - Unlikely	C - Possible	B - Likely	A - Almost Certain
	< 10%	10-25%	25-50%	50-75%	>75%

Appendix B. HYSYS Models (PFD view)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Q-106
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AC - 1
Compressed CO2
Q-105 Heat Flow 1673 kW
Q-106 Heat Flow 1876 kW
Q-108 Heat Flow 3549 kW
MIX-002
Q-108
MIX-003
Q-109
Q-109 Heat Flow 2.048e+004 kW
Q-101 Heat Flow 5415 kW
Q-102 Heat Flow 4182 kW
Q-103 Heat Flow 3857 kW
MIX-001
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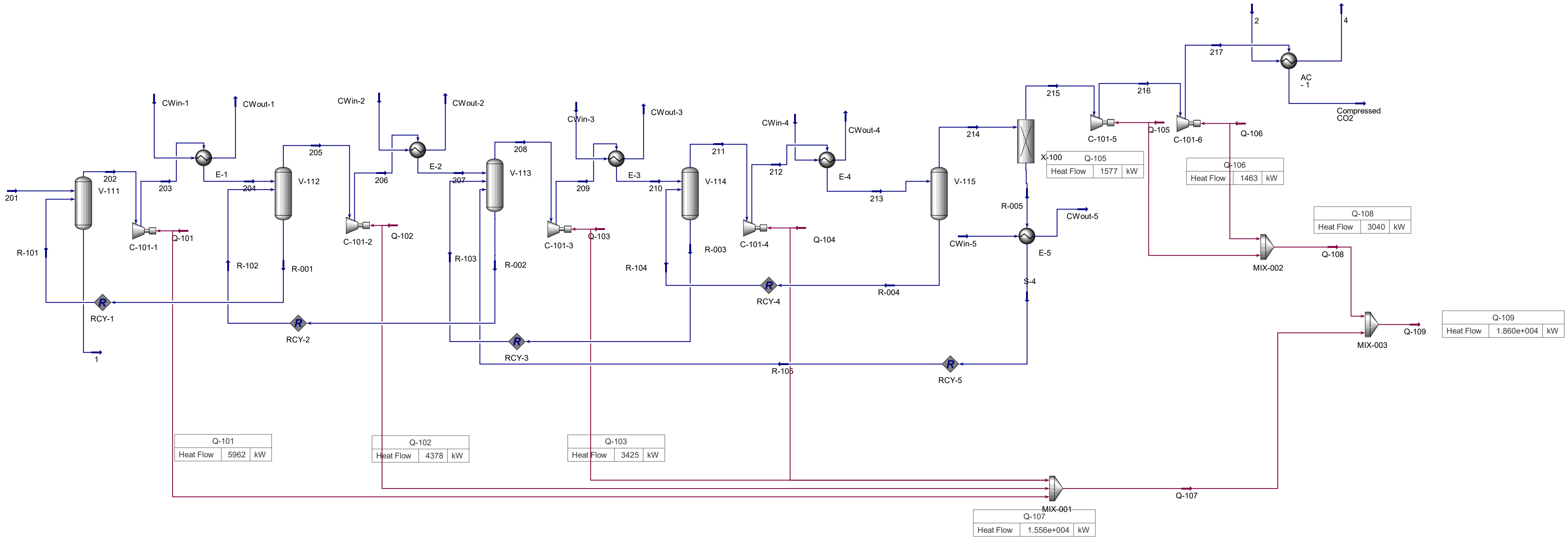
Q-107 Heat Flow 1.694e+004 kW



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Q-101 Heat Flow 5962 kW
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Q-103 Heat Flow 3425 kW
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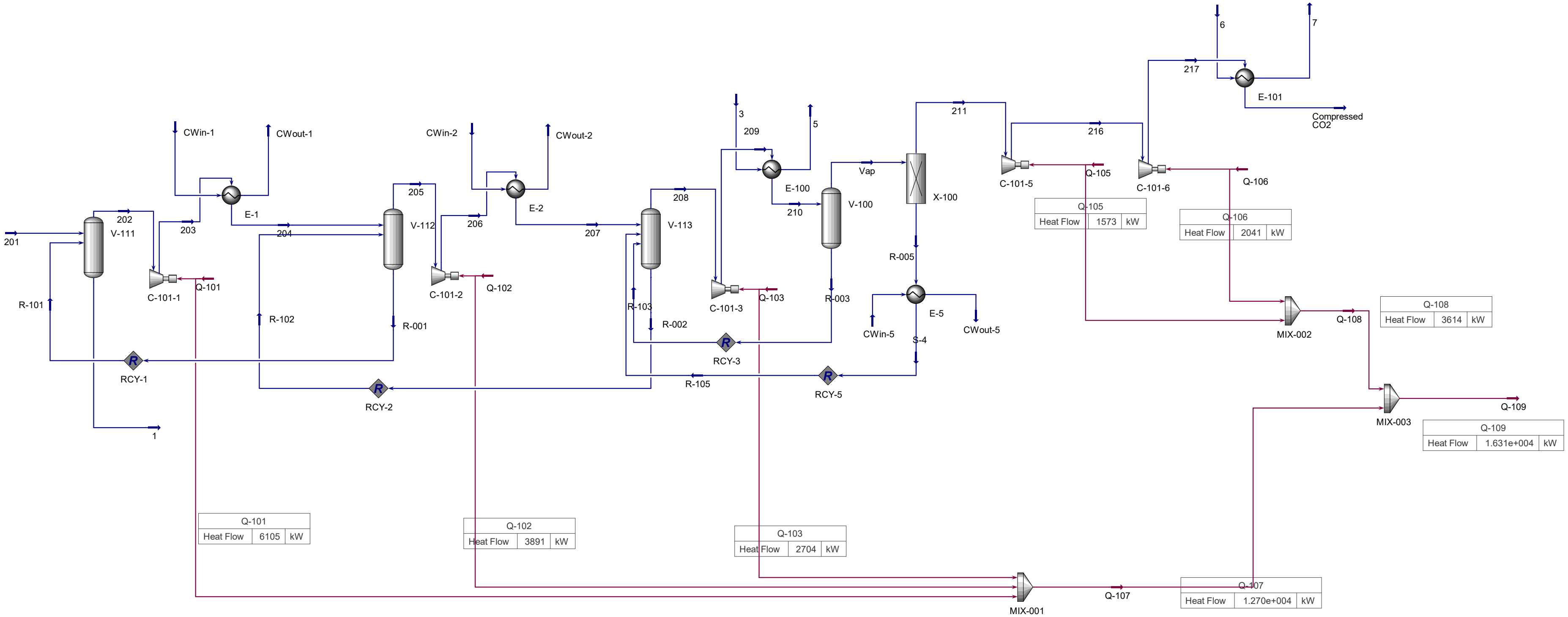
Q-107 Heat Flow 1.556e+004 kW



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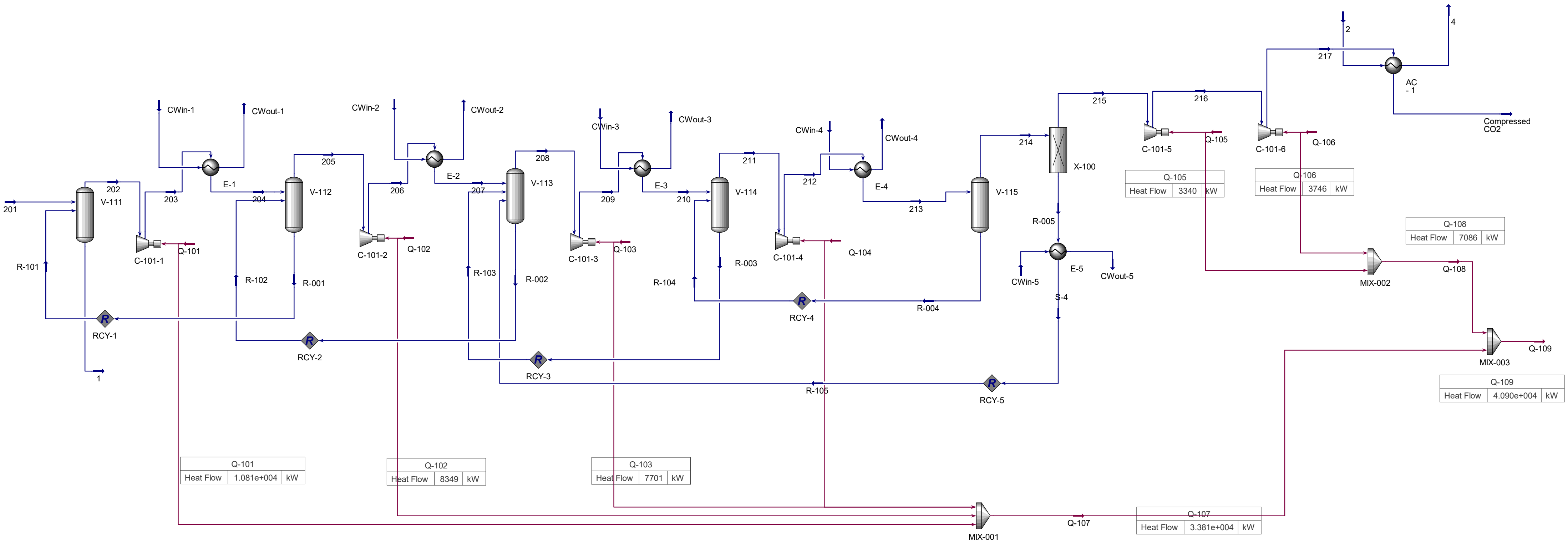

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Q-107
Q-108
Q-109
MIX-001
MIX-002
MIX-003
Compressed CO2
Q-101 Heat Flow 1.081e+004 kW
Q-102 Heat Flow 8349 kW
Q-103 Heat Flow 7701 kW
Q-105 Heat Flow 3340 kW
Q-106 Heat Flow 3746 kW
Q-107 Heat Flow 3.381e+004 kW
Q-108 Heat Flow 7086 kW
Q-109 Heat Flow 4.090e+004 kW

Appendix C. Equipment Schedules

LIST OF EQUIPMENT FOR EACH DESIGN, INCLUDING DIMENSIONS AND COST DATA.

APPENDIX REDACTED FOR COMMERCIALLY PROTECTED INFORMATION.

Appendix D. Thermoflex PEACE Output

ENERGY PLANT DESIGN AND COST DATA.

APPENDIX REDACTED - ENERGY PLANT NOT INCLUDED IN THIS ISSUE OF THE REPORT.

Appendix E. Cost Estimating Details

BREAKDOWN OF CAPEX AND OPEX DATA FOR EACH DESIGN.

APPENDIX REDACTED FOR COMMERCIALLY PROTECTED INFORMATION.

Appendix F. Vendor Typical TEG PFD

VENDORS SUPPLED PFD FOR A TYPICAL TEG SYSTEM.

APPENDIX REDACTED FOR COMMERCIALLY PROTECTED VENDOR INFORMATION.

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