Carbon Capture Ready (CCR) Report

DAMHEAD CREEK 2 POWER STATION

SCOTTISHPOWER

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1. Introduction

AECOM has prepared this Carbon Capture Ready (CCR) Report for the proposed 1,800 MW Damhead Creek 2 (DHC2) power station (hereafter referred to as the Proposed Development).

This updated full CCR report has been prepared to support the application to vary the Proposed Development within the already consented 1,800 MW envelope (allowing for the option of circa 1,500 MW output for the CCGT and up to 300 MW from open cycle gas turbine peaking plant) to demonstrate that it would remain technically feasible to retrofit Carbon Capture technology in the future to the proposed power station. CCR needs to be demonstrable for all new combustion generating stations with a generating capacity at or over 300 MW (and of a type covered by the European Union Large Combustion Plant Directive) as set out in Section 4.7 of the Overarching National Policy Statement for Energy[1], the Carbon Capture and Storage (CCS) Directive[2] and also the Industrial Emissions Directive[3].

This document has been produced in accordance with the requirements of the Department of Energy and Climate Change (DECC) November 2009 carbon capture guidance "*Carbon Capture Readiness (CCR) – A Guidance Note for Section 36 Electricity Act 1989 consent applications*".

1.1 Background

On 25 January 2011, ScottishPower secured consent under Section 36 of the Electricity Act 1989, for the development, construction and operation of a new 1,000 MW CCGT adjacent to the existing Damhead Creek Power Station. Further to this, on 28 July 2014 ScottishPower secured consent under Section 36(c) of the Electricity Act 1989 to increase the output of Damhead Creek 2 CCGT to 1,200 MW (12.04.09.04/265C). Subsequent to obtaining consent for the 1,200 MW scheme, ScottishPower identified the need to further develop the proposals and again secured consent for a power station of capacity up to 1,800 MW to take account of developing and improving turbine technologies.

To support the original Section 36 Consent application, a CCR report was submitted by ScottishPower in June 2009, addressing the requirements of the DECC Guidance on Carbon Capture Readiness for Applications under Section 36 of the Electricity Act 1989, dated November 2009. This original CCR report was subsequently modified in May 2010 to respond to Environment Agency (EA) questions and updated in January 2013 to reflect a previously consented increase in plant capacity from 1,000MW to 1,098MW, which was approved by DECC in March 2013. To support the variation to 1,200 MW scheme, a further revision to the CCR report was prepared in February 2014 to demonstrate continued compliance with the requirements of the CCR Guidance and Policy (Updated CCR Feasibility Note, ScottishPower, February 2014). The EA requested some additional information from ScottishPower following review of the revised CCR Feasibility Note and this was supplied in a subsequent letter from ScottishPower to DECC on 22nd April 2014 (ref: UB – X0002). Consent to construct and operate the 1,200 MW scheme was granted in July 2014.

To support the currently consented 1,800 MW scheme (hereafter referred to as the 1,800 MW CCGT only scheme option, though the consent does allow for a number of variations within that option as to whether it is constructed as single shaft or multi-shaft), a further revision to the CCR Report was prepared in May 2015 to demonstrate continued compliance with the requirements of the DECC CCR Guidance and Policy. The EA again requested some additional information from ScottishPower following review of the May 2015 revised CCR Report and this was supplied in a subsequent clarification letter from AECOM to the EA on 13th April 2015 (ref: 47072152). Consent to construct and operate the 1,800 MW scheme was granted on 23 October 2015.

ScottishPower now seek to further vary the existing consent to allow flexibility in the make-up of the plant to include up to 300 MW of OCGT peaking plant. The proposed development therefore now comprises a CCGT/OCGT power station with a total combined electrical capacity up to 1,800 MW, hereafter referred to as the '1,800 MW CCGT with peaking plant' scheme option. This application to vary the consent retains the option of constructing the already consented 1,800 MW CCGT-only scheme option but also includes provision of up to 300 MW as part of that capacity as OCGT units, with the CCGT capacity correspondingly reduced such that the combined output remains at 1,800 MW.As the 1,800 MW CCGT only option has been previously assessed and consented, this report focusses on

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[1]Department of Energy and Climate Change (DECC) (July 2011) Overarching National Policy Statement (NPS) for Energy: EN-1

[2]Directive on the Geological Storage of Carbon Dioxide (Directive 2009/31/EC), Article 33

[3]Directive on Industrial Emissions (Integrated Pollution Prevention and Control) (Directive 2010/75/EU), Article 36

the option to include up to 300 MW OCGT in order to demonstrate that sufficient space remains available and that it remains technically feasible to retrofit CC technology in the future for this option also.

1.2 Approach

The following approach has been used for this CCR assessment:

- A high level conceptual design for the Proposed Development has been established;
- A preferred carbon capture technology was identified for retrofit, based on thermal and process modelling, and current CCS technology availability;
- The size of the main CCS equipment required was established using thermal and process modelling. Site layouts were prepared to show that the equipment would fit into the land currently available;
- Geological storage sites with storage capacities capable of accepting the carbon output from the Proposed Development over its design life were identified, utilising the DTI study[4];
- Potential routes to transport the captured carbon dioxide (CO_2) from the Proposed Development site to the potential geological storage sites were identified;
- An economic assessment that encompasses retrofitting carbon capture technology, transport of CO_2 and the storage of CO_2 was carried out for the CCS plant to estimate the price of EU allowances for CO_2 which are necessary to make the Development feasible with CCS; and
- A high level assessment of the Health and Safety issues associated with the CCS plant was undertaken.

1.3 Report Structure

Based on the CCR guidance detailed in Section 2, this report is structured as follows:

- **Section 1** – Introduction;
- **Section 2** – Legislative Background;
- **Section 3 -** Proposed Development;
- **Sections 4, 5, 6, 7 and 8 -** Technical and Economic Feasibility Assessments for chosen technology, storage and transport; and
- **Section 9** – Health and Safety Assessment.

[4] Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK, 2006

2. Legislative Background

2.1 EU Directive on Geological Storage of Carbon Dioxide

The European Union (EU) agreed the text of a Directive on the Geological Storage of Carbon Dioxide on 17 December 2008. This text was published as the Directive on the Geological Storage of Carbon Dioxide (Directive 2009/31/EC) ("the Directive") in the Official Journal of the European Union on 5 June 2009, with the Directive coming into force on 25 June 2009.

Article 33 of the Directive requires an amendment to Directive 2001/80/EC (commonly known as the Large Combustion Plants Directive) such that developers of all combustion plants with an electrical capacity of 300 MW or more (and for which the construction / operating license was granted after the date of the Directive) are required to carry out a study to assess:

- Whether suitable storage sites for CO_2 are available;
- Whether transport facilities to transport CO_2 are technically and economically feasible; and,
- Whether it is technically and economically feasible to retrofit for the capture of CO_2 emitted from the power station.

  i.e. a "CCR Feasibility Study".

Article 36 of the Industrial Emissions Directive (which also originates from Article 33 of Directive 2009/31/EC on the Geological Storage of Carbon dioxide) also requires new large combustion plant to be CCR.

2.2 The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013

The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 (the CCR Regulations) came into force on 25 November 2013. These regulations transpose Article 36 of the Industrial Emissions Directive.

The regulations provide that no order for development consent (in England and Wales), or consent under section 36 of the Electricity Act 1989 (either in England and Wales, or Scotland), may be made in relation to a combustion plant with a capacity at or over 300 MWe unless the relevant authority has determined (on the basis of an assessment carried out by the applicant) whether it is technically and economically feasible to retrofit the equipment necessary to capture the carbon dioxide that would otherwise be emitted from the plant, and to transport and store such carbon dioxide from the site.

The regulations summarise the need for a CCR Feasibility Study and state (at Regulation 2(1)) that a: ""*CCR Assessment", in relation to a combustion plant, means an assessment as to whether the CCR Conditions are met in relation to that plant*".

In terms of the "CCR Conditions", CCR Regulation 2(2) states that: "*for the purposes of these Regulations, the CCR Conditions are met in relation to a combustion plant, if, in respect of all of its expected emissions of CO_2 –*

- *Suitable storage sites are available;*
- *It is technically and economically feasible to retrofit the plant with the equipment necessary to capture that CO_2; and,*
- *It is technically and economically feasible to transport such captured CO2 to the storage sites referred to in sub-paragraph (a)".*

Furthermore, CCR Regulation 5(1) states that: "*The appropriate authority must not grant a relevant Section 36 Consent unless the appropriate authority has determined whether the CCR Conditions are met in relation to the combustion plant to which the Section 36 Consent relates*".

In summary, CCR Regulation 5(3) states that: "*If the appropriate authority –*

a) *Determines that the CCR Conditions are met in relation to a combustion plant; and*
b) *Decides to make a relevant Section 36 Consent in respect of that plant*,

it must include in the relevant Section 36 Consent a condition that suitable space is set aside for the equipment necessary to capture and compress all of the CO2 that would otherwise be emitted from the plant".

2.3 Planning Policy

As the original scheme was consented under section 36 of the Electricity Act 1989, this CCR report accompanies a variation application to that existing consent under Section 36(c) of the Electricity Act 1989.

Whilst this scheme falls under the previous consenting scheme under the Electricity Act 1989, current applications for similar plant would fall under Section 15(2)(c) of the Planning Act 2008[5] and would therefore be a 'nationally significant infrastructure project' (NSIP). Under Section 104(3) of the Planning Act 2008, Development Consent Order (DCO) applications for NSIPs are required to be determined by the Secretary of State in accordance with policy set out in the relevant National Policy Statements (NPS), and it is considered that reference to the NPS is still relevant here even though this variation is applied for under the previous regime. As stated in the Overarching National Policy Statement For Energy *"all applications for new combustion plant which are of generating capacity at or over 300MW and of a type covered by the EU's Large Combustion Plant Directive (LCPD) should demonstrate that the plant is 'Carbon Capture Ready' (CCR) before consent may be given".*

2.4 Department of Energy and Climate Change Guidance on Carbon Capture Readiness

In June 2008, the UK Government published a consultation document 'Towards Carbon Capture and Storage'[6] to seek views on the steps it could take to prepare for and support both the development and deployment of carbon capture and storage technologies.

A response to this consultation was published in April 2009, alongside draft Guidance for applicants seeking Section 36 Consent for new combustion power stations at or over 300 MWe. The DECC Guidance implements article 34 of the Geological Storage of Carbon Dioxide (discussed in Section 2.1), and aims to reflect the Government's new CCR Policy. It was subject to an eight week consultation period that ended on 22nd June 2009. Following consultation, this Guidance ("the Guidance") was finalised in November 2009[7].

The DECC guidance also applies to applications to the Planning Inspectorate for generating stations of 50MW or more, under the Planning Act 2008.

Under the new CCR Policy, and as part of a CCR Feasibility Study applicants are required to:

- Demonstrate that sufficient space is available on or near the site to accommodate carbon capture and storage (CCS) equipment in the future;
- Undertake an assessment into the technical feasibility of retrofitting CCS equipment;
- Propose a suitable area of deep geological storage offshore for the storage of captured CO_2;
- Undertake an assessment into the technical feasibility of transporting the captured CO_2 to their proposed storage area;
- Assess the likelihood that it will be economically feasible within the power station's lifetime to link it to a full CCS chain, covering retrofitting of capture equipment, transport and storage; and,
- If necessary, apply for and obtain Hazardous Substance Consent (HSC) when applying for consent.

This CCR report has therefore been prepared to fulfil the requirements of the DECC November 2009 guidance as set out below:

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5 HMSO (2008) 'The Planning Act'

6 Department for Business Enterprise and Regulatory Reform (BERR) (June 2008) 'Toward carbon Capture and Storage, A Consultation Document',

7 Department of Energy and Climate Change (DECC) (November 2009) 'Carbon Capture Readiness (CCR) – A Guidance Note for Section 36 Electricity Act 1989 consent applications'

- Technical Assessment of Sufficient Space for CCS Equipment: An assessment of appropriate space set aside to accommodate future carbon capture equipment is provided in **Section 4** of this report.

- Technical Assessment of Feasibility of CCS Retrofit: Annex C of the Guidance provides a detailed advisory checklist of the information to be included in a CCR Feasibility Study report on the technical assessment of the feasibility of retrofitting CCS equipment for a New Natural Gas Combined Cycle Power Station using Post-Combustion Solvent Scrubbing. **Section 5** of this report deals with the technical response to these requirements for the proposed Damhead Creek 2 power station.

- Technical Assessment of Storage of Captured CO_2: In accordance with the guidance, at least two fields or aquifers with an appropriate CO_2 storage capacity, which have been listed in either the “valid” or “realistic” categories in the DTI’s 2006 study ‘Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK’, should be proposed as suitable CO_2 storage locations for the Development. Such sites are identified in **Section 6** of this report.

- Technical Assessment of Transport of Captured CO_2: The Guidance states that the feasibility of any proposed site for a new combustion station will be influenced by the availability of transport routes to the proposed storage area. The technical assessment of transporting the captured CO_2 to the storage area proposed for DHC2 is provided in **Section 7** of this report.

- Economic Assessment of Feasibility of CCS: The Guidance states that the main aim of the economic assessment is to provide an indication of the future likelihood of a retrofit of CCS equipment, CO_2 transport and storage of CO_2 being economically feasible at some stage during the proposed plant’s operational lifetime. This is developed in **Section 8** of this report.

- Health and Safety Analysis: An analysis of Health and Safety issues associated with the CCS plant including consideration of whether a Hazardous Substances Consent may be required for the CCS plant proposed for DHC2 is provided in **Section 9** of this report.

3. Description of the Proposed Development

3.1 Plant Location

DHC2 will constitute Phase 2 of the Damhead Creek Power Generation Development on the Hoo Peninsula, Kent, and will be located on land immediately adjacent to the existing operational Damhead Creek CCGT Power Station. The Site is located approximately 5km northeast of Gillingham and 15km east of Gravesend in north Kent. (National Grid Reference 581250, 172830). The site location is shown in **Figure 1**.

The factors that influenced the selection of the plant location are:

- Increasing generation capacity of existing power station;
- Availability of sufficient land;
- Current land use (the Proposed Development will be built on undeveloped land adjacent to the existing DHC1 site, on the existing power station site);
- Compatibility with relevant Local Plans, i.e. the Proposed Development is not in conflict with Medway Local Plan;
- Proximity to suitable utilities and grid export connections (availability of 400 kV National Grid transmission system, natural gas and transport infrastructure to accommodate construction traffic);
- Suitability for Carbon Capture and Storage Readiness (CCR).

The site boundary for the application is presented in **Figure 2**[8]. The total area of the Proposed Development Site is approximately 17.5 hectares (ha) comprising the following three main areas:

- Area 1 is where the majority of the new DHC2 CCGT will be constructed and lies to the east of the existing Damhead Creek CCGT Power Station (also referred to as the 'triangle site'). The developable area is 8.4 ha in extent;
- Area 2 is 3 ha in extent and lies to the north-west of the existing Damhead Creek CCGT Power Station. This land consists of hardstanding and is not currently in use. As per the layout for the already consented 1,800 MW CCGT only scheme option, up to 3.0 Ha of this area is allocated for the cooling system for the future CCS plant proposed, to be connected via overground or underground pipework to the rest of the CCS plant located in Area 3; and
- Area 3 in total is approximately 6.1 ha in extent and lies to the north-east of the existing Damhead Creek CCGT Power Station. Approximately 4.65 ha to be used temporarily for car parking and the storage of materials / equipment during construction, and will ultimately be set aside to provide sufficient land area to ensure there will not be any barriers to the retrofit of carbon capture plant at a future date. 1.3 ha of the plot will be required to accommodate the open cycle gas turbine peaking plant and 0.15 ha will be required for the new CCGT. The remaining part of Area 3 will be used as ecological enhancement and mitigation. The total site area available for carbon capture equipment therefore extends to 71,000 m^2

8 For high resolution drawing refer to Figure 2 in the EIR which this report accompanies

Figure 1: Site Location Plan

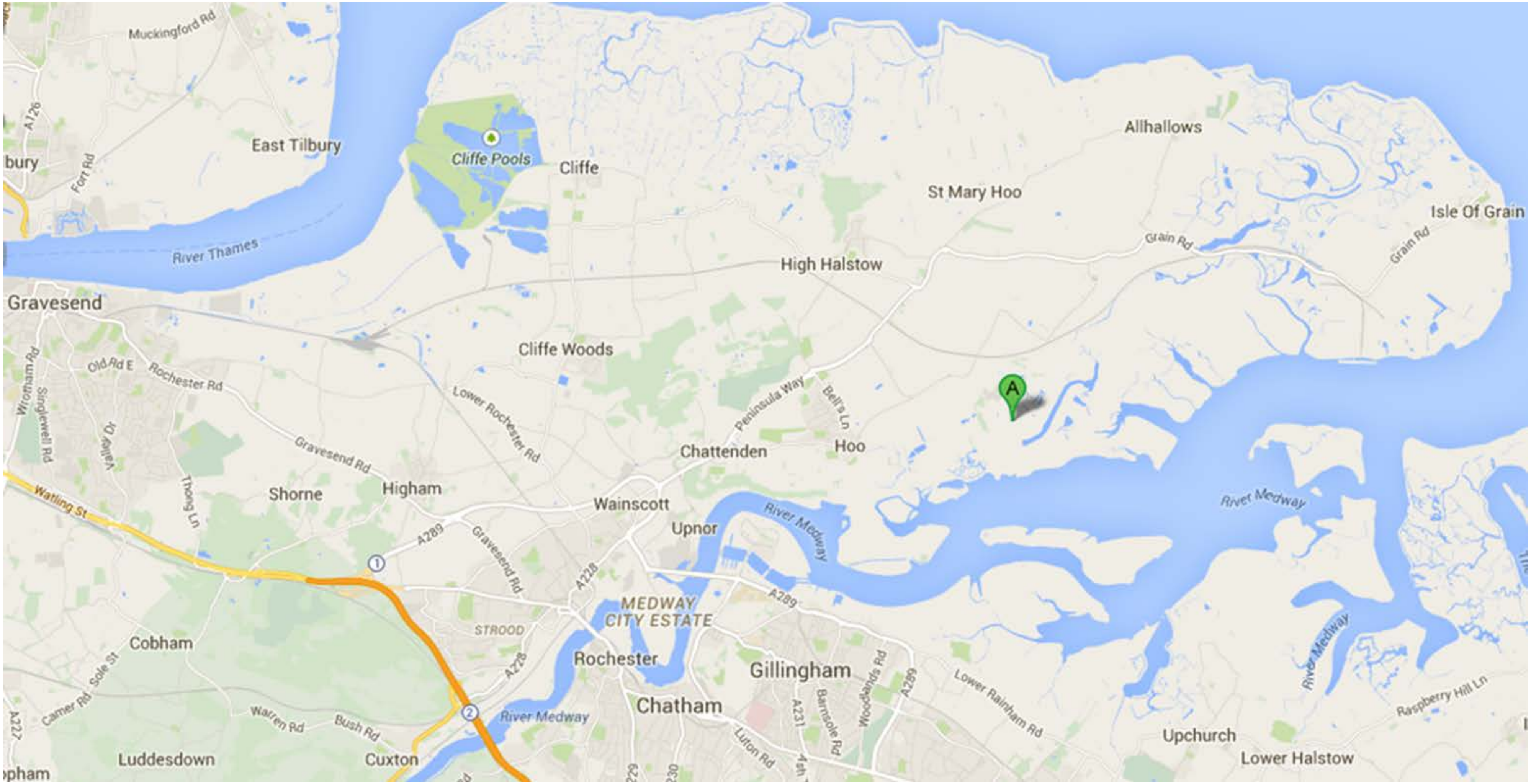
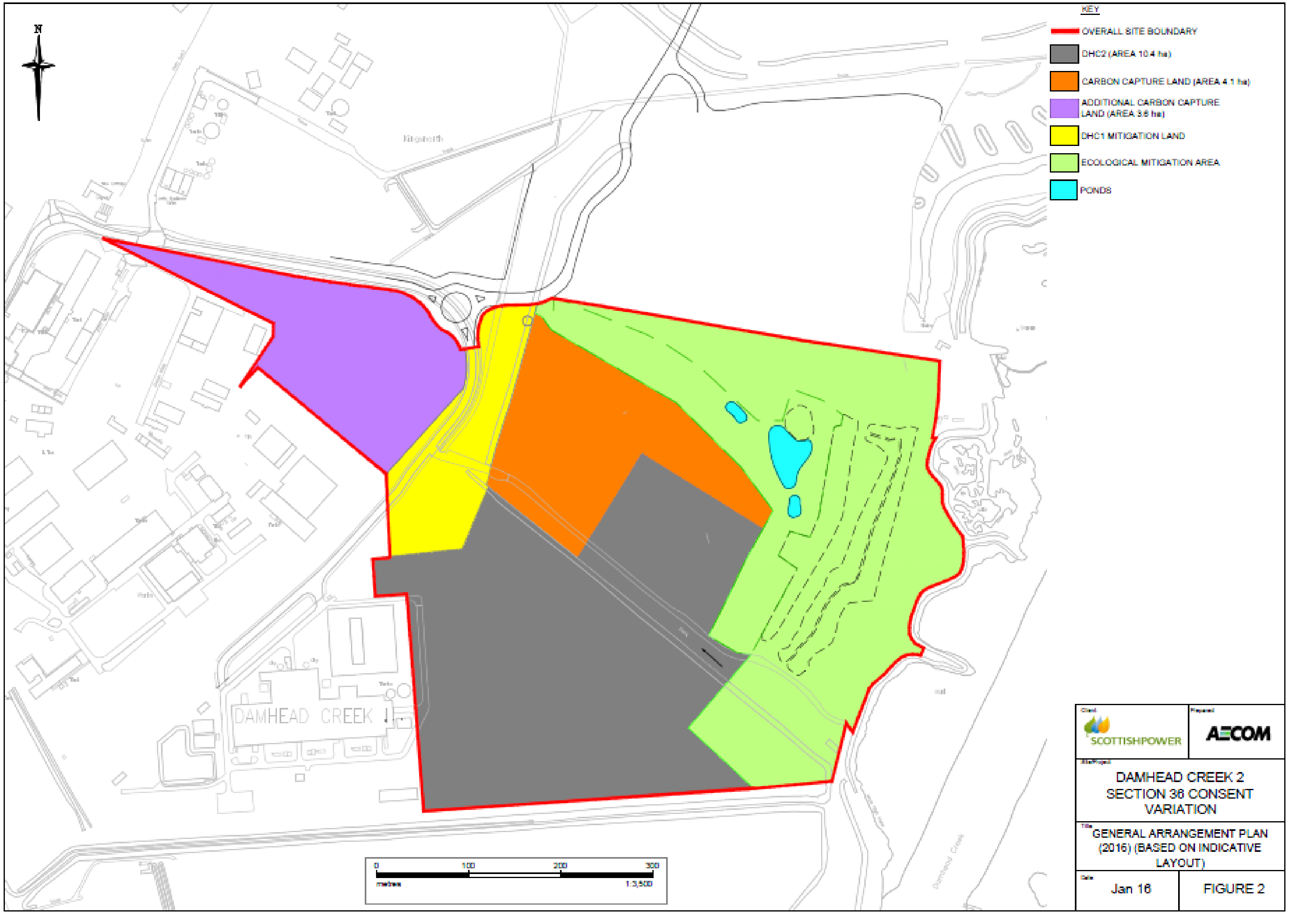


Figure 2: Proposed Development Site Boundary and Indicative Layout



3.2 Plant Description

As outlined in the Environmental Information Report (EIR) that accompanies and supports this variation application, the Proposed Development (DHC2) for this variation is the construction, commissioning and operation of a CCGT with a net electrical output capacity of circa 1,500 MWe and a peaking plant of up to 300 MWe with a combined net power output of up to 1800 MWe (though it is noted the most likely make up will be circa 1,550 MWe CCGT and 250 MWe of OCGT). Both power plants will be located adjacent to the existing Damhead Creek CCGT Power Station site located on the southern side of the Hoo Peninsula, to the east of Chatham and Rochester. The plants will be fired on natural gas from the UK National Transmission network; no back-up firing on distillate fuel is proposed. As with the existing Damhead Creek power station. the proposed CCGT plant will be air cooled. As set out previously, the already consented 1,800 MW CCGT only scheme option is also retained.

A detailed design and final technology selection of the CCGT have not been completed however, for the proposed 1,800 MW scheme, the most likely identified arrangement for the CCGT would consist of (2x) gas turbines (GT) in combined cycle with one (1x) steam turbine (ST) in multi-shaft configuration.

Each gas turbine package will comprise an air intake filtering system, an air axial compressor, a combustion chamber, gas turbine-generator, exhaust duct and silencer and other auxiliaries. The combustion system will be a dry low-NOx (DLN) system, which limits emissions of NOx to the atmosphere whilst keeping low concentration levels of CO.

Flue gas leaving the GTs at high temperature is routed to dedicated heat recovery steam generators (HRSG) before being discharged to the stacks. In the HRSGs, additional flue gas energy is recovered by raising and superheating steam at different pressures. The steam is expanded in the steam turbine, which is used to drive steam turbine equipment which is then converted into electricity in the ST generator. After the steam expansion in the ST, the steam at low temperature and pressure is condensed in the air cooled condenser (ACC). Air is used as the sole cooling medium. The condensate is pumped to the feedwater tank/de-aerator and then to the HRSG evaporators closing the steam cycle.

The estimated net power output of the proposed CCGT shall be circa 1520 MWe with an estimated net electrical efficiency in low heating value (LHV) basis of around 60% at 100% load and ISO reference conditions (60% of relative humidity and 15.5°C), based on current technology.

In addition to the main CCGT, it is also proposed that an open cycle gas fired peaking plant is installed at the site with a net rated capacity below 300 MWe. It is anticipated that the peaking plant shall consist of two (2x) Gas turbines operating in open cycle and will be operated periodically for short operating hours, when there is a peak power demand or frequency control required by the National Grid. The total output capacity of the Proposed Development will not exceed 1,800 MW.

Each generating module may have an individual stack, or alternatively the flues from each unit may be grouped together in one multi-flue stack. This will be determined during the preliminary design and subject to the findings of the air quality assessment.

The CCS plant shall be sized to process the flue gas generated in the main CCGT power plant only. In accordance with the DECC November 2009 CCR guidance, where an application for a variety of generating units types is received (e.g. combined cycle and open cycle turbines) the 300 MW threshold is applied to the new units of the same type on the site. The proposed electrical output capacity of the open cycle peaking plant does not meet the 300MW capacity requirements of CCR and therefore an analysis of future retrofitting of CCS to the peaking plant is not required under the current guidance.

A schematic of the power generation and CCS process associated with the Proposed Development is provided in **Figure 3**. Three CCS trains are considered to be appropriate for a two unit H-Class CCGT configuration, due to the volume of CO_2 generated.

Table 3-1 presents performance data of the Proposed Development. The performance data is estimated at ISO conditions (60% of relative humidity and 15.5°C) and 45 mbar of vacuum pressure in the condenser of the CCGT. A typical National Grid natural gas composition has been used for estimating the performance of the development.

Figure 3: General Process Block Diagram

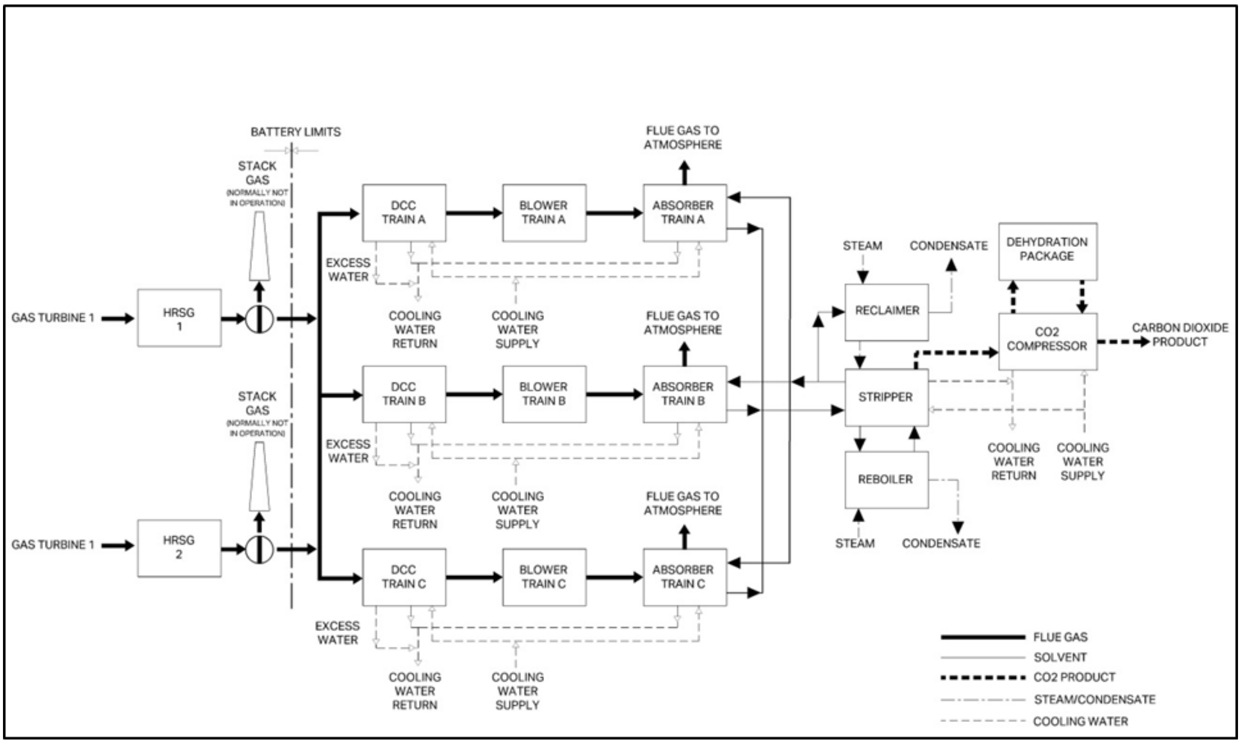


Table 3-1: Performance Data (CCGT and Peaking Plant)

Parameter	Design	Peaking Plant
Net Power MW	1520	247
Net (LHV) efficiency %	~60%	33.7
Net heat rate kJ / kWh	5937	10683
NOx Emissions as NO2 ppm vd@ 15% O2 kg/h	 25 392.2	 40 183.2
CO Emissions ppm vd@ 15% O2 Kg/h	 9 85.9	 6 16.7

Note: Emission concentration values are indicative, to be confirmed by turbine vendors

3.2.1 Flue Gas Composition and Conditions

Details regarding the CCS plant feed gas composition and flow rate were provided from initial engineering design calculations for the Proposed Development. The information provided is for the flue gas after the heat recovery steam generator (HRSG), which is proposed to be directed to the stacks (see Table 3-2).

Table 3-2: Gas Turbine Exhaust Gas

Parameter	Design (1 unit)	Peaking Plant
Exhaust gas mass flow per stack (kg/s)	1012.9	410.8
Stack exhaust gas temperature °C	88	546
Composition (mole %)		
N2	74.04	74.93
O2	11.1	13.75
CO2	4.5	3.25
H2O	9.5	7.17
Ar	0.89	0.9
SO2 ppmvd (@15%O2)*	0.215	0.215

* Assuming maximum H_2S content in Natural gas of 5mg/Nm^3

3.3 Proposed Carbon Capture and Storage Technology

The current European position is that the carbon capture plant would not be installed until CO_2 capture is either mandated or economically and technically viable. The current Emissions Performance Standard (EPS) set by the UK Government for new power generating stations is set at a level (450 g CO_2/kWh) that would not require CCS to be installed on new build gas-fired power stations. This level is proposed by UK Government to be maintained for consented plants until 2045.

Currently there are a number of carbon capture technologies being developed, namely:

- Pre-combustion carbon capture;
- Post combustion carbon capture; and
- Oxy-combustion carbon capture.

Although at the time of eventual installation, it is probable that the number of potential technologies will have increased, this CCR feasibility assessment focuses solely on the technology that is the most developed and closest to commercial deployment at present, as required by the DECC guidance.

As any CCS would have to be retrofitted to the DHC2 plant at some point in the future after several years of operation, this CCR assessment has focussed on the potential use of post combustion carbon capture, as this would be the most suitable of the three potential CCS technologies for retrofitting to an existing operational CCGT.

The feasibility of CCS for the Proposed Development has therefore been assessed on the basis of the best currently available post combustion carbon capture technology which, for carbon capture from combustion flue gases, is using amine based solution.

Further justification as to the choice of CCS technology considered most appropriate for the Proposed Development is provided in **Annex A**.

3.3.1 Process Design Basis

The conceptual design of the carbon capture system proposed for DHC2 has been based on the ISO reference conditions, i.e. 60% relative humidity and 15.5°C.

The following information has also been assumed:

Treated Flue Gas

- Design CO_2 Recovery Rate: 90%;

- Amine based solution content: Less than 3 ppmv (at the detailed design phase, the need for a lower amine solution concentration will be evaluated when considering potential odour impacts).

CO_2 for Sequestration

- Volume: 4 million tonnes per annum (mtpa) based on 90% capture efficiency and assuming the CCGT will be in operation 7884 hrs per year (90% load factor), recognising that this exceeds the envisaged long term load factor of 80% for the plant outlined in the EIR, and is therefore conservative;
- Pressure: >100 bar (and must be dehydrated to prevent corrosion of the steel pipe and hydrates formation);
- Temperature: Cool to 35 - 40° C to enter pipeline;
- CO_2 Pipeline length: ~250-300km depending on selected storage location;
- CO_2 Pipeline diameter: 25-35 cm.

Space Potentially Available for CCS

- Total: 76,500m^2 of the overall Proposed Development Site.

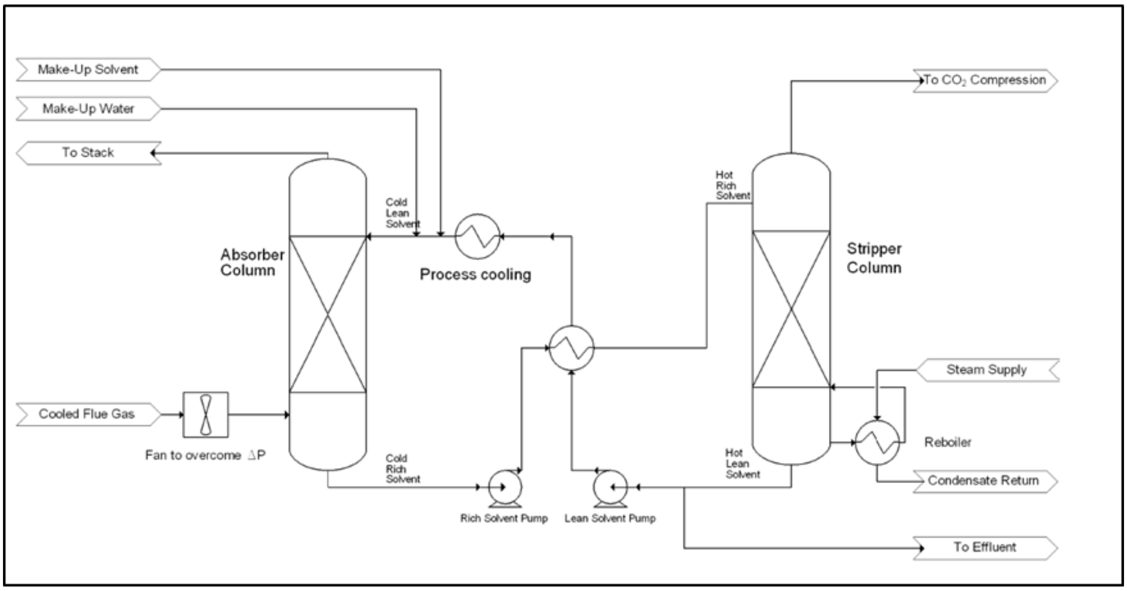
Post Combustion Amine Scrubbing

As discussed, the feasibility of CCS for the Proposed Development has been assessed on the basis of post combustion amine based absorption. The post-combustion amine scrubbing carbon capture process consists of the following main process stages.

- Flue gas cooling;
- CO_2 absorption;
- CO_2 stripping;
- Flue gas discharge;
- CO_2 discharge; and
- CO_2 compression.

A simplified process flow diagram is presented in **Figure 4**.

Figure 4 – Post Combustion Amine Scrubbing Carbon Capture Process



The Flue gas generated in the CCGT power plant after leaving the HRSG at around 85-95 °C and with a CO_2 content of 3.5-4.5% vol., is directed to the carbon capture plant via an additional flue gas duct system. This flue gas system shall include a bypass system of the flue gases directly to the main stack by means of bypass and isolation dampers in case the CCS plant is unavailable.

In order to enhance the chemical CO_2 absorption process, the flue gas is cooled down to around 45-55°C. Options for flue gas cooling include gas-gas re-heaters and/or direct contact cooling (quenching) with water. After the cooling process, the flue gas is blown through an absorber column where it comes into contact with the liquid amine based solvent. Around 90% of the CO_2 in the flue gas is chemically absorbed through acid-base neutralization reactions with the amine. This creates a CO_2 rich stream of liquid solvent. The CO_2 rich solvent is pumped out of the absorber column and is heated in the cross lean to rich solvent heat exchanger before entry into a stripper column; the remaining exhaust gas is then vented to atmosphere.

In the stripper column the solvent is heated further in the re-boiler to circa 120 to 140°C. At this temperature the chemical bonds between the CO_2 and the amine based solution will break releasing the CO_2 in gas form. The lean liquid solvent is pumped from the bottom of the stripper, cooled in the cross heat exchanger, and further cooled before reentry to the absorber by an external cooling medium. The CO_2 gas, containing a high concentration of steam, exits at the top of the stripper. It is cooled down in the stripper overhead cooler and the water is separated in the knock-out drum reducing considerably the concentration of water in the CO_2 stream.

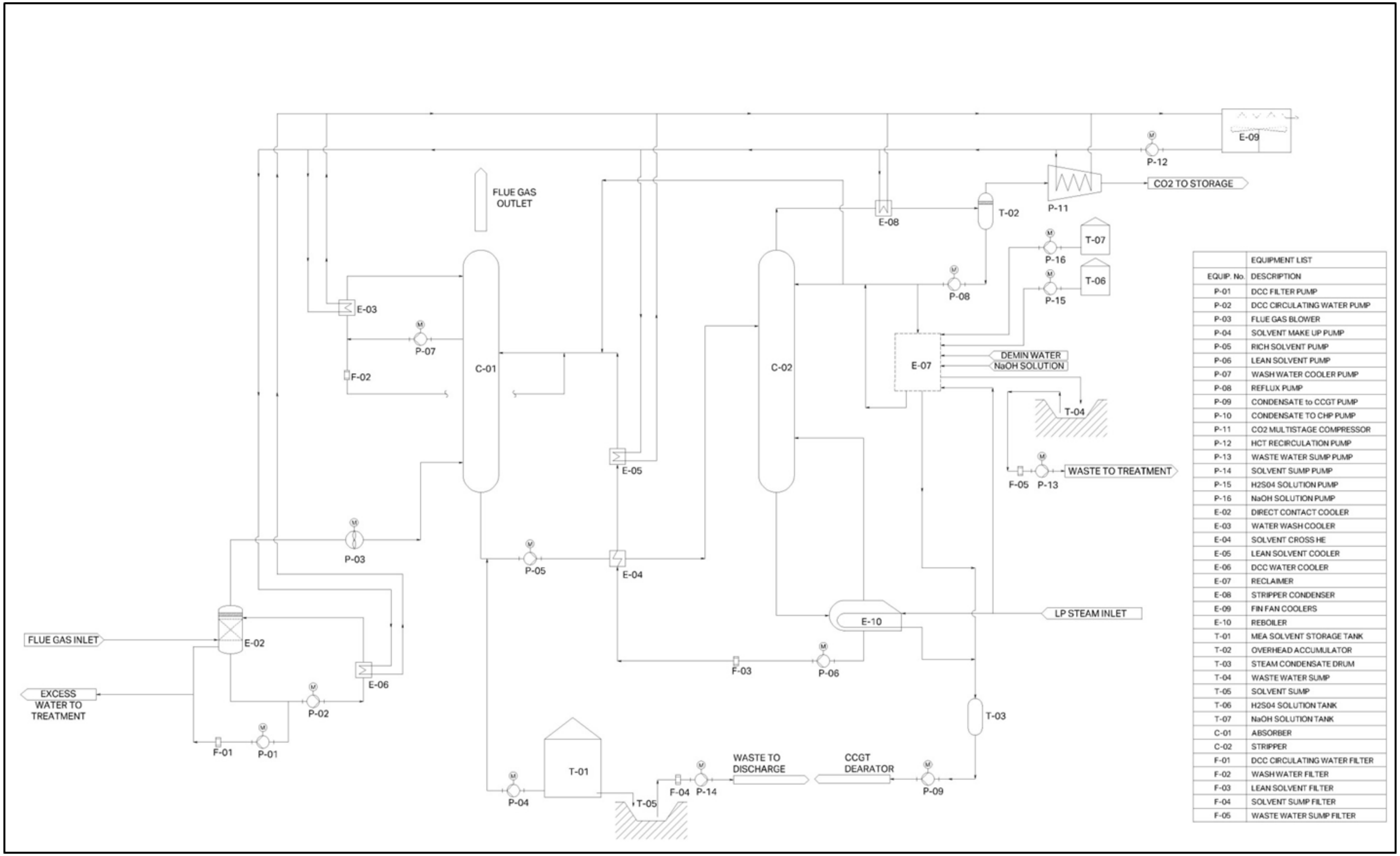
The CO_2 stream is then compressed in an intercooled multistage compressor. Additional water is condensed from the CO_2 stream in the compressor intercoolers, and separated in the inter-stage knock-out drums. When CO_2 pressure level approaches a value of around 30barg in an intermediate compression stage, the stream is dehydrated in a traditional glycol based plant (TEG plant) to reduce the content of H_2O to around 50 ppm. The dehydrated CO_2 stream is finally compressed to the CO_2 pipeline supercritical pressure.

Amine based absorption plants typically can capture approximately 90% of the CO_2 in a CCGT plant flue gas stream and can result in an end CO_2 purity of over 99%.

A typical state of the art 'H Class' Gas Turbine (GT) exhaust flow at base load would require the absorption of 6050 to 4750 tonnes per day (tpd) of CO_2 at 100% load. With the flue gas volumetric flow rate being so high, it's anticipated that three (3x) CO_2 absorption columns will be required. Each absorption train requires a Direct Contact Cooler (DCC), blower, absorber and associated filters, heat exchangers and pumps. There can be several absorptions trains all linked to a single regeneration and CO_2 stripper and compression/dehydration package.

A process diagram schematic showing a typical amine based CCS train is provided in **Figure 5**.

Figure 5: Process flow diagram for an amine absorber train



4. Technical Assessment – Space On Site

As shown in **Figure 2**, the space available for the carbon capture plant at DHC2 comprises an area of approximately 76,500m^2 (comprising 30,000m^2 in Area 2 and 46,500m^2 in Area 3). No space located off site would need to be used for the carbon capture plant except as a transient construction laydown area.

4.1 Footprint Estimate

As the detailed design of the CCS Plant is yet to be finalised, for the purposes of this CCR feasibility report a 'worse case' footprint area has been estimated using the following sources of information:

- DECC CCR Guidance;
- Imperial College Paper on CCS Footprint Review;
- AECOM databases on CCS plant design from other CCGT retrofit concept projects;

On this basis the indicative footprint has been estimated based on the calculations and the list of major equipment presented in Table 4-1. A conservative design margin is applied to allow for access and maintenance.

An indicative 'worse case' total footprint of the CCS plant has been calculated at approximately 71,000m^2 (23,667 m^2 per CCS train and the supplemental plant) i.e. within the space available on site.

Table 4-1: Worse Case Footprint Estimate of One Train

Tag No.	Equipment	Number of Pieces	Length / m	Width / m	Foot Print Area / m^2
P-01	DCC Filter Pump	2	1.5	1.5	2.25
P-02	DCC Circulating Water Pump	2	2.2	2.2	4.84
P-03	Blower	1	17	12	204
P-04	Solvent Make-up Pump	2	1	1	1
P-05	Rich Solvent Pump	2	3.5	2.5	8.75
P-06	Lean Solvent Pump	2	3.5	2.5	8.75
P-07	Wash Water Circulating Pump	2	1.5	1.5	2.25
P-08	Reflux Pump	2	1.5	1.5	2.25
P-09	Condensate to Deaerator Pump	2	2	2	4
P-12	HCT Recirculation Pump	2	2	2	4
P-13	Waste Water Sump Pump	2	1	1	1
P-14	Solvent Sump Pump	2	2.5	1.5	3.75
P-15	H2SO4 Solution Pump	2	1.5	1.5	2.25
P-16	NaOH Solution Pump	2	1.5	1.5	2.25
E-02	DCC column	1	13.5	Circular	182.25
E-03	Wash Water Cooler	2	2.5	1.5	3.75
E-04	Solvent Cross Exchanger	1	4.5	1.5	6.75

Tag No.	Equipment	Number of Pieces	Length / m	Width / m	Foot Print Area / m^2
E-05	Lean Amine Cooler	1	6	2.5	15
E-06	DCC Water Cooler	1	8	3.5	28
E-07	Reclaimer	1	14	8.5	119
E-08	Stripper Condenser	1	14	2.8	39.2
E-09	Fin fan coolers	209 modules with 4 fans/module	126	157	19,782
E-10	Re-boiler	1	16	11	176
T-01	Amine Storage Tank	1	5.5	Circular	30.25
T-02	Overhead Accumulator	1	4.2	Circular	17.64
T-03	H2SO4 Solution Tank	1	2.8	2.8	7.84
T-04	NaOH Solution Tank	1	2.8	2.8	7.84
C-01	Absorber	1	ϕ 12.5	Circular	156.25
C-02	Stripper	1	ϕ 11	Circular	121
F-01	DCC Circulating Water Filter	1	0.5	0.5	0.25
F-02	Wash Water Filter	1	0.5	0.5	0.25
F-03	Lean Slovent Filter	1	7	4.2	29.4
F-04	Solvent Sump Filter	1	0.5	0.5	0.25
F-05	Waste Water Sump Filter	1	0.5	0.5	0.25
F-06	Activated Carbon Filter	1	4.5	4.5	20.25
P-11-1	Compressor Stage 1 Intercooler	1	8	2	16
P-11-2	Compressor Stage 2 Intercooler	1	8	2	16
P-11-3	Compressor Stage 3 Intercooler	1	8	2	16
P-11-4	Compressor Stage 4 Intercooler	1	8	2	16
P-11-5	Compressor Stage 5 Intercooler	1	8	2	16
P-11-6	Compressor Stage 1 Drum	1	ϕ 2	Circular	4
P-11-7	Compressor Stage 2 Drum	1	ϕ 1	Circular	1
P-11-8	Compressor Stage 3 Drum	1	ϕ 0.7	Circular	0.49
P-11-9	Compressor Stage 4 Drum	1	ϕ 0.5	Circular	0.25
P-11-10	Compressor Stage 5 Drum	1	ϕ 0.3	Circular	0.09
P-11-11	CO_2 Compression Unit	1	11	7	60

Tag No.	Equipment	Number of Pieces	Length / m	Width / m	Foot Print Area / m^2
P-11-12	CO_2 Dehydration Unit	1	10	20	200
A-01	Antifoam System	1	6	6	36
A-02	Instrument Air System	1	8	8	64
A-03	Nitrogen Blanketing System	1	5	5	25
				Total 1 train	21,500
				Total 1 train (including margin)	25,500
				Total 3 train (including margin)	76,500

The information regarding gas flow presented in Section 3 indicates a requirement for a CCS plant capable of processing a maximum of 12,100 tonnes gas per day (tpd) from the two CCGT turbines.

4.2 Footprint Comparison

A comparison of the footprint of the CCS plant proposed for DHC2 against an indicative minimum footprint of a CCGT with post combustion carbon capture published in Table 1 of the DECC Guidance as amended by the Imperial College paper is presented in Table 4-2. It is of note that the indicative footprints presented in the guidance are based on a net plant capacity of 500 MW without carbon capture (i.e. one third that of the Development).

Table 1 in the 2009 CCR Guidance provides an indicative CCR space requirement based on a 500 MW (net) power plant. For a CCGT power plant with post-combustion carbon capture, the indicative CCR space requirement was initially provided at 3.75ha for 500MW,which equates to 75 m^2/MW.

However, following the publication of the CCR Guidance, the indicative CCR space requirement was reviewed by Imperial College, London. The Imperial College review concluded that the footprint estimates presented in the 2009 CCR Guidance were overly conservative and recommended the reduction of the indicative CCR space requirement for a CCGT power plant with post-combustion capture by 36%. Therefore, the corrected indicative CCR space requirement is 2.4ha for 500 MW. This equates to 48 m^2/MW.

In addition, the review by Imperial College further detailed additional scope for a reduction in the indicative CCS space requirement by 50% to 1.875 ha (including the reduction of 36%) considering technology advances and layout optimisation. This equates to 37.5 m^2/MW. However, the paper also states that “such a reduction can only be justified on the basis of a detailed engineering design (which is not a requirement for consent under Section 36)” rather than only a linear scaling of this value.

Table 4-2 Comparison of Land Footprint of Proposed Carbon Capture Plant and DHC2

Case	Generation Capacity prior CO_2 Capture Installation / MWe	Generation Footprint / m^2	Peaking Plant	CO_2 Capture Footprint / m^2	Total Footprint / m^2
Original Indicative Minimum (1)	*500*	*23,800*	*N/A*	*37,500 (75m²/MW)*	*62,000*
Revised Indicative Minimum (2)[9]	*500*	*23,800*	*N/A*	*24,000 (48m²/MW)*	*48,000*
Revised Indicative Minimum (3) - considering technology advances and layout optimisation	*500*	*23,800*	*N/A*	*18,750* ***(37.5m²/MW)***	*42,550*
Revised Indicative Minimum (3)[10] (considering technology advances and layout optimisation)	1,500	71,400	*N/A*	56,250 ***(37.5m²/MW)***	127,650
Revised Indicative Minimum (3)[11] (considering technology advances and layout optimisation)	1,800	85,680	*N/ A*	67,500 ***(37.5m²/MW)***	153,180
1,500MW CCGT + <300MW Peaking Plant	1,500	91,000	13,000	71,000 ***(47.33m²/MW)***	175,000
1,800MW CCGT (S.36 consented)	1,800	104,000	N/A	71,000 ***(39.3m2/MW)***	175,000
DHC 2 Plot /Area 1 / m²	*N/A*	*84,000*	*0*	*0*	*84,000*
Former substation / Area 2 / m²	*N/A*	*0*	*0*	*30,000*	*30,000*
CCS Land / Area 3 / m²	*N/A*	*7,000*	*13,000*	*41,000*	*61,000*
Total		*104,000*		*71,000*	*175,000*

As shown in Table 4-2 the approximate minimum land footprint requirement for the Damhead Creek 2 CCS scheme is 56,250 m^2 at 1,500 MW and 67,500 m^2 at 1,800 MW (based on the revised indicative requirement of 37.5 m^2/MW provided by Imperial College London). The land available at site for the Damhead Creek 2 CCGT Power Station CCS scheme is 71,000 m^2 (comprising 30,000 m^2 in Area 2 and 41,000m^2 in Area 3). Therefore, the land available at site for the Damhead Creek 2 CCGT Power Station CCS scheme is sufficient to meet the approximate minimum land footprint requirement for both 1,800 MW CCGT only and 1,800 MW CCGT with peaking scheme options.

In order to demonstrate that sufficient space has been made available for the proposed CCS plant, illustrative site plans have been prepared, as illustrated in **Figure 6**, which indicate:

- The footprint of the combustion plant;
- The location of the capture plant;

[9] Imperial College (2010) Assessment of the validity of "Approximate minimum land footprint for some types of CO_2 capture plant" provided as a guide to the Environment Agency assessment of Carbon Capture Readiness in DECC's CCR Guide for Applications under Section 36 of the Electricity Act 1989, Appendix A3,

[10] Based on a linear scaling approach of 42,550m^2 (4.25 ha) for a 500 MW (net) CCGT power plant with post-combustion CO_2 capture

[11] Based on a linear scaling approach of 42,550m^2 (4.25 ha) for a 500 MW (net) CCGT power plant with post-combustion CO_2 capture

- The location of the CO_2 compression equipment;
- The location of any chemical storage facilities; and
- The exit point for CO_2 pipelines from the site (the CO_2 Terminal Point) - the CO_2 terminal point has been placed to match the most likely onshore CO_2 pipeline route described in Section 7.

The CCS plant illustrative site layout shown in **Figure 6** covers an area of 7.65 ha. By allowing the plant to be generously laid out all the existing CCS space available at DHC2 has been utilised.

With regards to the proposed area of the CCS plant, the following points are made:

- Although Imperial College concluded that 18,750m^2 of space is required for CCS on a 500 MW plant (37.5m^2/MW). This is based on the use of hybrid cooling on the future CCS plant. However, DHC2 is an air cooled plant and similarly, any future CCS plant is likely to be air cooled due to constraints on the use of water for cooling at the site.
- Potentially, Gas to Gas Heat (GGH) Exchangers could be used within the design which may further reduce the footprint required for cooling by up to 25%. While such a Heat Exchanger would have its own plot implications it is considered that there would still be a net saving in land take. Within the layouts shown, no use of GGH Exchangers is currently considered.
- It is assumed that the control room for the CCS plant is centralised with the main CCGT control room within the CCGT footprint.

In the footprint estimate the following systems and equipment are considered:

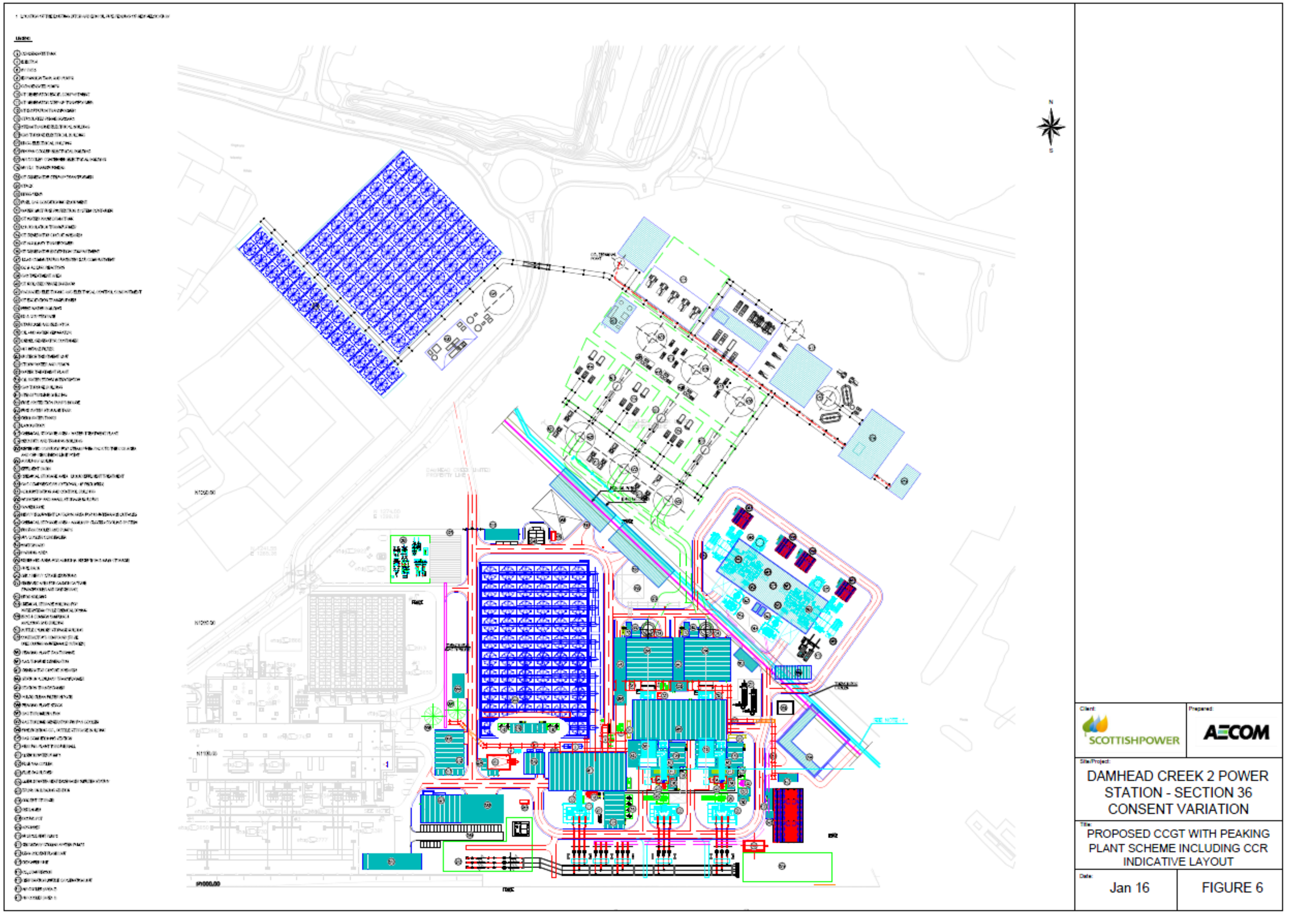
- Generation system (incl. use of auxiliary supply, steam supply);
- CO_2 capture equipment (incl. column sizing for absorber and stripper, number of trains);
- Cooling systems;
- CO_2 dehydration and compression (incl. number of compressors per train);
- Additional flue gas treatment (incl. scope to incorporate within existing facilities);
- Solvent/sorbent storage;
- CO_2 transport details (incl. pipelines);
- Space for construction;
- Appropriate space for health and safety considerations.

The space requirements will be reviewed on an ongoing basis as part of the required periodic Status reports, and will incorporate any developments in the design of the carbon capture plant for DHC2. In addition the land set aside for CCS will be appropriately managed so that it remains suitable to accommodate future CCS (e.g. prevented from becoming a wildlife reserve). It will also remain within the Applicant's ownership.

In terms of the land required for laydown during construction of the CCP, the laydown area would be determined and secured at the time of installation and would depend on the year of construction. On the expectation that CCR for DHC2 is unlikely to be required before 2030, existing DHC1 land could be used for this purpose, with the original station having exceeded its design life (commissioned 2001). This would free up around 8 hectares of land on the adjacent plot to DHC2 that is expected to remain within ScottishPower's ownership and therefore be available for CCS laydown purposes. It is also the case that there are substantial areas of land in and around the development site (former Kingsnorth power station, Kingsnorth Business Park, Kingsnorth Industrial Estate, etc) that could be available on a short term lease for the CCP construction and laydown areas.

This laydown area is not covered by the 71,000m^2 area set aside for the Carbon Capture Plant.

Figure 6: Conceptual Layout for the Proposed Development



5. Technical Assessment – Retrofitting Carbon Capture Technology

To demonstrate that the Proposed Development has been designed so that it would be technically feasible to subsequently retrofit carbon capture equipment in the future to the entire capacity of the proposed power station, the plant design has been assessed against the criteria presented in Annex C of the DECC guidance note[7].

5.1 C1 Design, Planning Permissions and Approvals

The feasibility of CCS for the Proposed Development has been assessed on the basis of the best currently available technology, which for post combustion carbon capture from flue gases is capture using amine based absorption.

An outline level plot plant for the plant is provided in **Figure 6**.

5.2 C2 Power Plant Location

Information on the location of the Proposed Development has been provided in Section 3 and it is shown in **Figures 1** and **2**.

It is anticipated that the exit point for the captured CO_2 from the plant will be located as shown in **Figure 6** at the north of the site. The final location will be selected depending on the agreed method and route of CO_2 transportation.

Where appropriate, pipe racks will be used to transfer the compressed and dehydrated CO_2 to the defined exit point. This is achievable as the pipe will have an internal diameter of circa 0.65 m assuming an allowable velocity of 3.5 m/s, due to the dense phase of the CO_2.

Further information on the transport and storage of captured CO_2 is provided in Sections 6 and 7.

5.3 C3 Space Requirements

The total footprint of the carbon capture plant has been calculated and is presented in Section 4. This footprint has been derived from the footprint of each piece of equipment, allowing spacing for piping and maintenance etc. Equipment sizing has been scaled off previous projects involving amine based systems and gas flow design information.

The footprint was used to prepare the plot plan presented in **Figure 6** that demonstrates that space has been allocated for the following:

- CO_2 capture equipment, including any flue gas pre-treatment, and CO_2 drying and compression;
- Space for routing flue gas duct to the CO_2 capture equipment;
- Steam turbine island additions and modifications;
- Any extensions or additions to the balance of plant on the CCGT units where necessary to cater for the additional requirements of the capture equipment;
- Construction and operational vehicle movement;
- Space for storage and handling of amines and handling of CO_2, including space for infrastructure to transport CO_2 to the plant boundary; and
- Major plant deliveries.

In terms of the land required for laydown during construction of the CCP, the laydown area would be determined and secured at the time of installation and would depend on the year of construction. On the expectation that CCR for DHC2 is unlikely to be required before 2030, existing DHC1 land could be used for this purpose, with the original station having exceeded its design life (commissioned 2001).

Further information regarding space requirements is provided in the following sections.

5.4 C4 Gas Turbine Operation with Increased Exhaust Pressure

The gas turbines cannot accommodate the increased backpressure due to the addition of CCS units. Therefore, the design for the carbon capture plant includes a booster fan/blower to compensate the pressure drop through the CCP (primarily in the absorbers, direct contact cooler and dampers) which is of the order of 140 mbar.

Based on the flue gas flow rate of around 860m^3/s with a nominal pressure rise of 140 mbar and an overall efficiency of 85%, a two stage axial fan with a power rating of approximately 16.5 MWe per train, or 33MWe in total has been included in the carbon capture plant power requirement.

When the carbon capture plant is designed, detailed specifications for this fan will be developed. These would include provisions for the power drop across the absorber and the gas-gas re-heater, and the volume and mass flow rate of the flue gas into the absorber. Whilst it is not possible to provide detailed specifications for the booster fan at this stage without performing a more detailed design of the carbon capture plant, there is an adequate provision on the carbon capture plant for its installation and space of (210m^2) for a booster fan / blower has been allocated to each train in the carbon capture plant.

5.5 C5 Flue Gas System

The following flue gas system is proposed for the CCS plant.

5.5.1 Isolation and Bypass Dampers

The flue gas exiting the HRSG is routed to a bypass or diverter damper, from where it may be directed either directly to the stack (e.g. during start up or fault conditions) but for normal operation through the CCS plant.

This arrangement allows for the CCS plant and the CCGT plant to have a reduced degree of mutual dependency, and to provide enhanced operability in safety and fault conditions. In the event of a major equipment fault such as the booster fan, the CCGT can be switched to bypass mode until the fault is corrected. Plant safety issues are also more readily addressed. Safety studies and dynamic analysis of the flue gas path will be necessary at the design stage, and will determine such parameters as fan control loops and the type and actuation speed of the bypass dampers.

5.5.2 Flue Gas Cooling

The absorption process requires a flue gas cooler to lower the flue gas temperature to around 45-55°C in order to enhance the CO_2 chemical absorption and to minimise amine degradation. The flue gas is routed from the HRSG to the Direct Contact Cooler (DCC), E-02, which quenches the flue gas to an acceptable temperature for absorption. A small slipstream of the circulating cooling water is routed through the DCC Water Filter (F-01) to remove particulate build-up. A portion of this particulate free stream is returned to the DCC the other portion is headed to treatment plant. Cool, saturated flue gas from the DCC is extracted through the Blower (P-03) which is required to overcome the frictional losses in the ducting, GGH, DCC and Absorber.

A gas-to-gas Ljungström type heat exchanger could be included prior to the DCC. Heat would be transferred from the hot untreated flue gas stream to the cold treated purified flue gas stream. This heat exchanger would reduce the duty of DCC and would improve the dispersion of the treated flue gases into the atmosphere. For this study this heat exchanger has not been sized for this study but could be considered if required in detailed design efforts.

5.5.3 CO_2 Absorber

The cooled flue gas from the DCC is fed to the bottom of the counter current Absorber (C-01) where CO_2 in the flue gas is absorbed by the solvent. Flue gas enters near the bottom of the Absorber and flows upward through packed beds. CO_2 reacts chemically with the solvent and is absorbed into the bulk solution. Rich solvent leaves the bottom of the Absorber and is transferred to the Stripper (C-02) by the Rich Solvent Pump (P-05).

Stripped flue gas, vaporized amine based solution and water travels through the chimney tray and enters the top packed bed. This third packed bed is the wash section of the column, where wash water is used to recover the vaporized amine and water. A Wash Water Circulating Pump (P-07) circulates the wash water between the Absorber and Wash Water Cooler (E-03).

Flue gas is vented to the atmosphere via the stack on top of each Absorber at a temperature of around 45°C. No evaluation of the potential frequency of visible plumes from the final flue gas discharge from the CCS plant has been undertaken at this stage. This will be evaluated at the detailed design stage and if required appropriate mitigation employed.

5.5.4 CO_2 Stripper

Rich solvent leaves the bottom of the Absorber and is routed to the rich to lean amine solution cross heat exchanger which increases the efficiency of the process by heating the rich amine to >100°C using the heat in the lean amine stream from the Stripper. The preheated rich amine enters the Stripper below the wash section of the column through a liquid distributor and flows down through the packed beds counter-current to the vapour from the Reboiler (E-10) releasing the absorbed CO_2. The lean amine from the bottom of the Stripper is transferred to the rich to lean solution cross heat exchanger, where it is cooled against the rich amine from the absorber train.

To remove impurities from the amine system, ~10% of the cooled amine is routed to the Amine Filter Package F-03. This removes suspended solids and high molecular weight amine degradation products.

5.5.5 Stripper Overhead Condenser

The overhead vapour from the Stripper at ~100°C and 0.8 barg is cooled to ~35°C in the overhead Condenser (E-08), condensing some of the water content. The two-phase enters the separation drum (T-02) separating the product gas which is routed to the CO_2 Compression / Dehydration unit (P-11).

5.5.6 Amine Reclaimer

The amine based solution degrades in the presence of different elements that lead to amine oxidation to salts, thus a purification stage is necessary to prevent the accumulation of heat stable salts. The reclaimer is a kettle type reboiler where this purification process takes place. There is a feed of steam, water and sodium hydroxide to allow for part of the degraded amine based solution solvent recuperation through chemical reactions. The reclaimer is expected to operate in intermittent basis when the content of dissolved salts be above curtained predefined value.

5.5.7 Centrifugal Compressor

The wet CO_2 from the Stripper Reflux Drum is routed to an intercooled CO_2 Compressor (P-11). The captured CO_2 is compressed to meet the delivery pressure required for the pipeline and remain dry.

5.5.8 Dehydration Unit

A dehydration package is needed for reducing the water content in the CO_2 stream to 50 ppm (wt.) to assure that condensation in the CO_2 pipeline does not occur. At this concentration, the dew point is at around -46 deg C, which makes the condensation unlikely. .

A glycol based dehydration package, being a mature technology in natural gas dehydration processes, is well suited to be used for this application. For the expected operating temperatures, Triethylene-glycol (TEG) is better than other glycol based absorbents. This package is installed after the second intercooling stage of the CO_2 compression package. That way, the pressure remains below CO_2 critical point.

It is considered that there are no foreseeable technical barriers to retrofitting and integration of CCS into the flue gas system.

5.6 C6 Steam Cycle

A supply of ~170 kg/s of low pressure (3.5 bar) steam at ~250^{o}C is required for the amine regeneration process.

In accordance with best practice guidance it is proposed that the steam is extracted from the CCGT IP/ LP crossover as steam conditions at this point would be suitable for the stripper re-boiler duty. Based on previous studies this approach using an integrated provision is considered to result in a lower efficiency impact compared to the use of a standalone boiler.

The steam extraction would impact the power generated in the steam turbine as less steam flow rate would be expanded in the low pressure turbine section. It is estimated that the ST power output would decrease by circa 75 MWe. The steam extracted would be a considerable proportion of the total steam flow rate, therefore there are some technical issues which need to be addressed during detailed design, i.e. the effect on the ST steam operation and control, especially at part load.

5.7 C7 Cooling Water System

The amine based CCS process has a considerable cooling duty which is estimated at 825MWth. The main cooling demands within the CCS process comprise:

- Flue gas DCC cooler;
- Lean solution to absorber cooler;
- Stripper overhead cooler; and
- CO_2 compression intercoolers.

Hybrid cooling towers are typically the preferred cooling system technology to meet these cooling demands, however these will not be utilised at DHC2 due to water availability constraints, as with the existing Damhead Creek 1 power station and the proposed DHC2 CCGT, both of which are cooled by Air Cooled Condensers. For the CCS plant dedicated dry fin-fan coolers are proposed.

The illustrative site layout in **Figure 6** include provisions for air (fin-fan) cooling.

5.8 C8 Compressed Air System

There is no requirement within a standard amine based CCS plant for any compressed air for process purposes, but only for the supply of instrument air and general service air to the CCS plant. This requirement shall be specified at the detailed design stage. Depending on the exact requirements, e.g. the number and duty of air actuated valves, this may be met by connecting to the compressed air services of the main CCGT plant, or by installing a new dedicated system for the CCS plant. A new compressed air system would include but not be limited to compact air compressors (2x100%), Air prefilters (2x100%), Air after filters (2x100%), Air inlet filters (2x100%), Heatless regenerative dryers (2x100%), a Wet receiver (1x100%), Instrument air receivers (2x100%), Pressure regulators (2-3) and Air after coolers if required (2x100%).

Sufficient space has been allocated for a new compressed air system.

5.9 C9 Raw Water Pre-treatment Plant

The CCS plant will only have a small demand of make-up raw water. This water shall make up for small losses in of the amine/water solution loop caused by amine degradation or carry over, and for losses in the closed loop cooling system. If required, this can be supplied from mains water that is available at the site.

In fact the process will generate water by condensation of moisture from the flue gas in the direct contact cooler (DCC) and the CO_2 compressor inter stage cooler knock-out drums. This water will be slightly acidic due to dissolved CO_2, but will be entirely suitable for treatment in the main CCGT plant WTP. No dedicated CCS WTP or pre-treatment plant is therefore foreseen.

5.10 C10 Demineralisation Plant

As discussed in Section 5.9, facilities provided for the Proposed Development are considered sufficient to meet the make-up water requirements of the CCS plant. The carbon capture and compression processes are not large demineralised water consumers. Additional water requirements will be to replace the water removed during the amine reclaiming process. At present this is estimated to be approximately 34.5 tonne/hr peak per train as per Fluor's Econoamine FG process, although there are studies[12] which suggest that demin water quality is not required for the amine solution make-up water and only good quality water is required. Should demin water quality be required, there is still sufficient

[12] Source: IEA Greenhouse Gas R&D Programme (IEA GHG), "CO_2 capture ready plants", 2007/4, May 2007.

space in the proposed layout to include a dedicated water treatment plant which is estimated to take up around 8mx12m. The required water quality and quantity shall be specified at detailed design phase.

5.11 C11 Waste Water Treatment Plant

It is expected that the detailed design of the CCP will include appropriate surface water drainage systems including oil interceptors as necessary and consistent with surface water drainage systems for power stations in general. Space provision for site drainage e.g. surface water and process water drains has been included in the worst case footprint allocation for each piece of equipment.

Waste water will be generated from the cooling of the flue gas resulting in partial condensation of water vapour within the direct contact cooler. The volume of wastewater generated will vary with ambient conditions but is not likely to exceed 40 t/h depending on the gas turbine selected.

The following table lists the waste water treatment requirements

Table 5-1: Waste Water Output

Description	Units	Value
Drain Water from CO_2 compression CCS plant #1	kg/s	10
DCC CC Train 1 drain	kg/s	12
DCC CC Train 2 drain	kg/s	12
DCC CC Train 3 drain	kg/s	12
Total Reclaimer waste (sludge)	m^3/h	11.9
Active carbon consumption	kg/day	866

The waste water drain will be relatively clean although may have a slightly elevated pH. It is envisaged it will be routed to the Damhead Creek 2 effluent treatment plant for pH neutralisation prior to discharge or could be used as raw water for the WTP without further treatment.

The standard amine based process includes a reclaimer for recovery of amine based solution and removal of degradation products, solids and salts formed in the carbon capture process. This operation will generate a low volume effluent stream which it is envisaged will be directed to the DHC2 effluent treatment plant.

Activated carbon is also consumed in the active carbon filters for the circulating amine based solution. A slip-stream is constantly directed to a mechanical prefilter and then to the active carbon filter for removal of solids delaying the reclaiming activity. It is estimated that 0.08kg of carbon per tonne of captured CO_2 shall be consumed. This solid waste material shall be disposed of for off-site regeneration/recycling via a licensed waste contractor.

If appropriate, this stream could be combined with the condensed water vapour stream if that would neutralise the pH of both streams for example, although the details would be confirmed at the detailed design stage for the CCP. The detailed design would also identify whether any modifications to the Damhead Creek 2 effluent treatment system were required at that time.

The provision of space for any waste water treatment is included in the illustrative site layouts in **Figure 6.**

5.12 C12 Electrical

In addition to the utilities described previously, the CO_2 capture system will require the following utilities.

- Electrical Power Distribution System;
- Fire Protection and Monitoring System.

The total power requirement of the CCS plant is approximately 89.5MW. Further detail of individual users is presented in Table 5-2.

Table 5-2 Electrical Requirements

Description	Units	Value
CO_2 compressors	MWe	41
Booster Fan (3x unit)	MWe	32.5
Fin Fan Coolers (for 3x trains)	MWe	7
Amine based solution circulating pumps	MWe	4
Other miscellaneous power demands	MWe	5
Total	**MWe**	89.5

It is currently proposed that the electrical demand of the CCP is taken directly from the output of the Damhead Creek 2 CCGT, reducing the export capacity of the CCGT to the National Grid accordingly.

5.13 C13 Plant Pipe Racks

Space provision for plant pipe racks has been included in the footprint allocation for each piece of equipment and is shown in **Figure 6**.

5.14 C14 Control and Instrumentation

The control and instrumentation system for the carbon capture plant is anticipated to be incorporated into the Distributed Control System of the Development, i.e., the control room. However, space is available on the carbon capture plant for standalone control equipment should this be required.

5.15 C15 Plant Infrastructure

It is anticipated that major plant may be delivered by road. There are not considered to be any access constraints that could impede any future construction activities.

The provision of space for additional plant infrastructure is illustrated in the illustrative site layout in **Figure 6**.

The site is accessible from the existing road network and is not considered to have any access constraints which could impede any future construction activities. Whilst the final provisions for plant infrastructure will be detailed in the final design of the carbon capture plant, at this stage it is envisaged this may include the use of temporary road surfaces if required for construction vehicles.

6. Technical Assessment – CO_2 Storage

The maximum theoretical volume of CO_2 anticipated to be captured during the lifetime of the Proposed Development is 140 million tonnes (assuming approximately 4Mt CO_2/year from the two CCGT units, an average lifetime capacity factor of 90% and a 35 year design lifetime of the power station). In reality, it is highly unlikely that the CCGT will operate to a 90% load factor over its lifetime and a 60% load factor is more realistic, which would equate to a total CO_2 volume of approximately 93Mt. In the previous CCR Feasibility reports prepared for the 1,200 MW and 1,800 MW schemes the worst case CO_2 storage requirements were conservatively estimated at approximately 84 Mt CO_2 and 97 Mt CO_2 respectively[13]. These predicted volumes are therefore consistent.

The UK's major potential sites for the long-term geological storage of CO_2 are offshore depleted hydrocarbon (oil and gas) fields and offshore saline water-bearing reservoir rocks / aquifers.

6.1 Oil and Gas Fields

Oil and gas fields are regarded as prime potential sites for CO_2 storage for the following reasons:

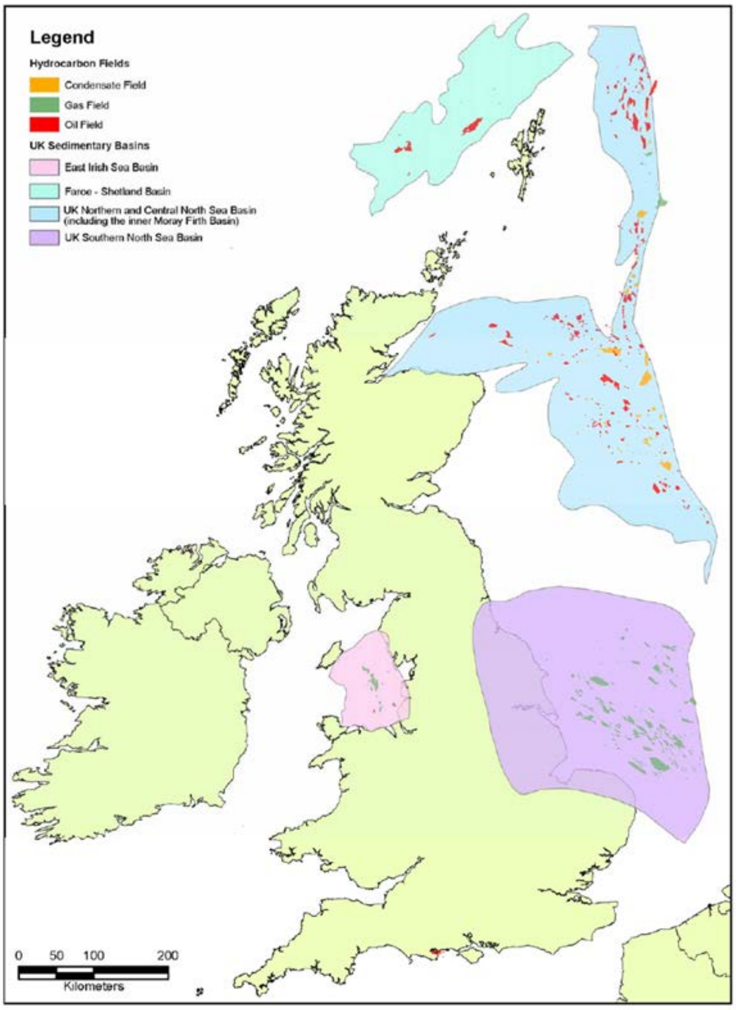
- they have a proven seal which has retained buoyant fluids, in many cases for millions of years; and
- often a large body of knowledge and data regarding their geological and engineering characteristics has been acquired during the exploration and production phases of development.

As shown in **Figure 7** most of the UK's large offshore oil fields are in the Northern and Central North Sea Basin. However, there are three major fields (Clair, Foinaven and Schiehallion) in the Faroes-Shetland Basin, two (Douglas and Lennox) in the East Irish Sea Basin, and one (Beatrice) in the Inner Moray Firth Basin. The UK's offshore gas fields occur mainly in two areas: the Southern North Sea (SNS) Basin and the East Irish Sea Basin. However, there is also one major gas field (Frigg) in the Northern and Central North Sea Basin.

The DECC CCR guidance suggests that the simplest and most appropriate means of demonstrating there are "no known barriers" to CO_2 storage is by delineating on a map a suitable storage area in either the North Sea or Irish Sea (Morecambe Bay). Within this delineated area, there should be at least two fields or aquifers, with an appropriate CO_2 storage capacity, which have been listed in either the "valid" or "realistic" categories in the DTI's 2006 study of UK Storage Capacity "Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK", October 2006 (DTI Study 2006), which is provided in Annex 1D of the CCR Guidance.

[13] Assuming 75% lifetime load factor for the power station.

Figure 7: The location of offshore hydrocarbon fields and the major oil and gas-bearing sedimentary basins[14]



The Proposed Development is located in the south east of England approximately 5km northeast of Gillingham and 15km east of Gravesend in north Kent, therefore the nearest hydrocarbon fields to the Proposed Development are located in the Southern North Sea Basin. Based on the DTI Study 2006, due to their location and capacity the Hewett (L Bunter) and Leman gas fields in the South North Sea Basin are potential storage areas for the CO_2 captured from DHC2. Based on the total storage requirements of DHC2, Table 6-1 illustrates the percentage storage requirements on these two gas fields.

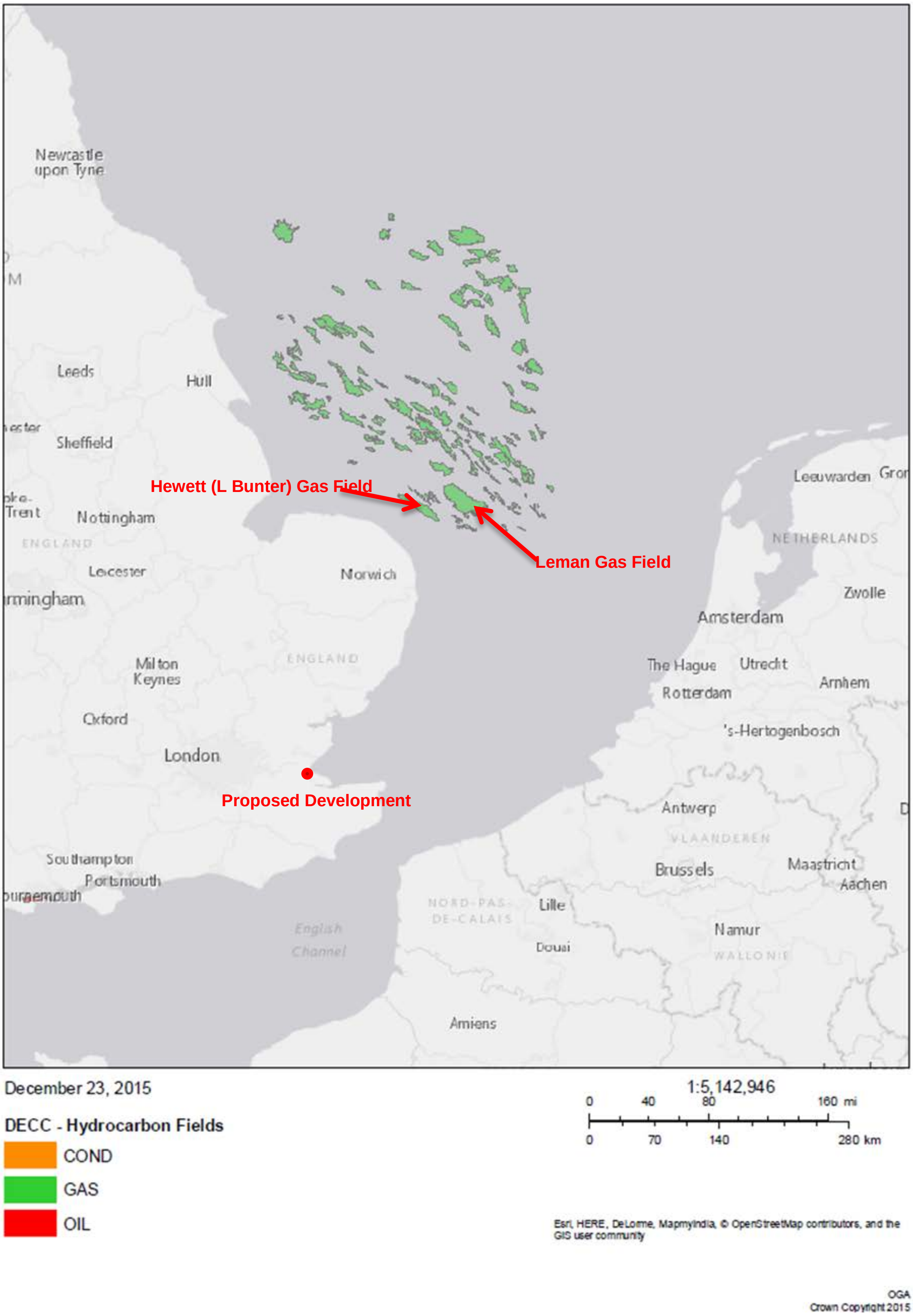
Table 6-1: Capacity of Proposed Geological Storage Areas

Field Name	Total Volume of CO_2 emitted by DHC2 / 10^6 tonnes	Capacity of Geological Storage Area / 10^6 tonnes	%
Hewett (L Bunter) Gas Field	Up to 140	237	59
Leman Gas Field	Up to 140	1,203	12

The location of these storage areas is illustrated on **Figure 8**.

[14] British Geological Survey (BGS) (October 2006) Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK (DTI/Pub URN 06/2027), prepared or the UK Department of Trade and Industry, now the Department of Business Enterprise and Regulatory Reform.

Figure 8: Map of Southern North Sea Oil and Gas Fields[15]



15 https://decc-edu.maps.arcgis.com/apps/webappviewer/index.html?id=adbe5a796f5c41c68fc762ea137a682e

In accordance with the DECC guidance, the gas fields listed in Table 6-1 are identified as 'realistic' storage locations in the DTI report[16].

The DTI study defines "realistic" capacity (p.6) as: "Realistic capacity applies to a range of technical (geological and engineering) cut-offs to elements of an assessment, e.g. quality of the reservoir (permeability, porosity, heterogeneity) and seal, depth of burial, pressure and stress regimes, size of pore volume of the reservoir and trap, nature of the boundaries of the trap and whether there may be other competing interests that could be compromised by injection of CO_2 (e.g. existing subsurface resources such as oil and gas, coal, water or surface resources such as national parks). This is a much more pragmatic estimate that can have some degree of precision, and gives important indications of technical viability of CO_2 storage."

It is recognised that in the future there may be competing interest for the identified CO_2 storage sites, as other carbon capture and storage projects become operational. It is also recognised that other CCR applications may also have identified the same geological fields for CO_2 storage capacity. According to the DECC Website (https://itportal.decc.gov.uk/EIP/pages/c02.htm) the Hewett Bunter gas field has three existing potential consented users comprising:

- The previously consented DHC2 requirements of 84 Mt CO_2;
- Willington C (200 Mt CO_2 March 2011);
- Gateway Energy Centre (GEC) (74 Mt CO_2 August 2011).

This gives a currently consented total of 358Mt and a remaining CO_2 storage capacity of 1 Mt of CO_2 when considering the combined capacity of the two Hewett Bunter Gas Fields (359MtCO_2). The DTI study identifies the Hewett Bunter Gas Field as being two distinct fields, i.e. the Hewett L Bunter and the Hewett U Bunter. However, according to the decision letter for Willington C prepared by DECC dated March 2011 "*The Secretary of State has been informed that the Bunter reservoirs were formed in the Triassic Age and therefore do not appear to be significantly compartmentalised, unlike reservoirs formed in the Permian Age. The Secretary of State is therefore of the view that the Hewett L Bunter and Hewett U Bunter can be considered as one storage field for CCR purposes*"[17].

The revised estimated storage requirement of DHC2 is up to 140 million tonnes of CO_2 (or more realistically 93Mt). Combined with the requirements of Willington (200Mt CO_2) and GEC (74 MtCO_2) this gives a new total amount of captured CO_2 of up to 414 million tonnes, which would therefore exceed the combined CO_2 storage capacity of the Hewett Bunter Gas Fields (359MtCO_2).

However, it is understood that an application to allow an increase in the permitted generation capacity of GEC from 900 MW to 1250 MW was submitted in 2014. The "Updated CCR Feasibility Study" which accompanies this variation application dated August 2014 indicates that *"the CO_2 storage requirements of GEC with the proposed increase in permitted generation capacity will be a maximum of approximately 84.2 Mt. Therefore, using the Hewett gas field with an increase in permitted generation capacity would result in its CO_2 storage capacity being exceeded. Accordingly is proposed that the preferred CO_2 storage area for GEC is changed to the Leman gas field as this will satisfy the CO_2 storage requirement of GEC with the proposed increase in permitted generation capacity and does not have any potential users[18]".*

Therefore, whilst the decision as to which specific storage site to use will not be made until eventual implementation of CCS, as shown in Table 6-2, using the updated information available regarding the preferred CO_2 storage area for GEC, the Proposed Development would require less than 90% of the remaining storage capacity of the Hewett L Bunter gas field over its 35 year lifetime. It is therefore considered that there are technically viable CO_2 storage facilities accessible to DHC2.

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16 British Geological Survey (BGS) (October 2006) Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK (DTI/Pub URN 06/2027), prepared or the UK Department of Trade and Industry, now the Department of Business Enterprise and Regulatory Reform.

17 https://itportal.decc.gov.uk/EIP/pages/projects/willington_ccgt_decision_letter.pdf

18 http://www.intergeneurope.com/development-projects/gateway-energy-centre-downloads

Table 6-2: Remaining Capacity of Proposed Geological Storage Areas

Field Name	Capacity of Geological Storage Area / 10^6 tonnes	Total Volume of CO_2 from other applicants/ 10^6 tonnes	Remaining Capacity of Geological Storage Area / 10^6tonnes	Total Volume of CO2 emitted by DHC2 / 10^6tonnes	%
Hewett (L Bunter and U Bunter)	237 (L) 122 (U) = 359	200 (Willington C)	159	Up to 140	Up to 88
Leman Gas Field	1,203	84.2 (GEC revised)	1,118.8	Up to 140	Up to 13

In addition, there are a large number of storage sites which exist in the same region that are capable of meeting the CO_2 storage requirements of the Proposed Development. Table 6-3 lists a number of storage sites, including those discussed above, in the SNS Basin that are identified in the DTI Study.

Table 6-3: Additional Potential Storage sites in the SNS Region

Field Name	Capacity of Geological Storage Area / 10^6 tonnes
Galleon	137
Hewett L Bunter	237
Hewett U Bunter	122
Indefatigable	357
Leman	1,203
V Fields	143
Viking	221
West Sole	143
Total	**2,563**

Whilst the decision as to which specific storage site to use will not be made until eventual implementation of CCS, Table 6-3 shows that the potential storage sites in the region have a storage capacity of in excess of 2,563 Mt CO_2. The Proposed Development would require less than 5.5% of this storage capacity in the SNS Basin over its 35 year lifetime.

Another possibility in the future is that there will be an available “CO_2 Network” in the region such that CO_2 from the Proposed Development and other plants in the area would be delivered to a “central hub”, such as the Thames hub previously proposed by E.ON. From this central hub, the captured CO_2 would be delivered to a number of storage sites. A discussion of the transport implications of this option is provided in Section 7.

The storage assessment will be reviewed on an ongoing basis as part of the two yearly Status Reports, with a view to incorporating developments in the updated design for the carbon capture plant for Damhead Creek 2.

7. Technical Assessment – CO_2 Transport

There are various options available for transporting CO_2 from point of capture to final geological storage, including on-shore transportation by pipeline, potentially use of rail or road tankers and off-shore transportation by pipeline or shipping.

It is proposed that the CO_2 captured from the Proposed Development will be transported to the storage site via pipeline. Transport via road or rail is not considered to be feasible or realistic given the volumes of CO_2 being transported. It is considered that tankers may have a role in smaller (demonstration scale) projects, but for larger volumes pipelines are the only practical option.

Within the onshore and near-shore area there are several options regarding the pipeline route. These routes, which are illustrated in **Figure 9**, include:

- A pipeline running via Damhead Creek along the River Medway;
- A pipeline running via Long Reach along the River Medway; or
- An onshore pipeline running north over the Hoo Peninsula and then along the Thames Estuary.

The indicative routes have taken into account the following considerations:

- An exit point from the site that is unlikely to be blocked by future developments outside of the site boundary; and
- The presence of designated sites, such as Sites of Special Scientific Interest (SSSI), Special Areas of Conservation (SAC), Special Protection Areas (SPA), Ramsar Sites, National Nature Reserves (NNR), Designated Parks and Gardens, Scheduled Ancient Monuments (SAMs) and Areas of Outstanding Natural Beauty (AONB).

At this stage the most likely option identified at present would be a pipeline leaving the north of the site across the Hoo Peninsula and then along the Thames Estuary, before continuing on to the storage sites (Hewett or Leman gas fields) in the South North Sea Basin. This is the preferred potential route which will be focused on in this CCR study.

This option is attractive because it avoids the internationally and nationally designated ecological sites along Damhead Creek and River Medway. Land easements and permissions would also need to be obtained but any new CCS project would need separate consenting at that time, so those land agreements would be secured as part of the consenting process.

It is recognised that a route to the south of the site has the potential to link into E.ON's previously proposed 'Thames Cluster' detailed in "Capturing Carbon, Tackling Climate Change: A Vision for the CCS Cluster in the South East" (2009). As shown in **Figure 10** the 'Thames Cluster' was intended to be a network of CO_2 pipelines which will link together power stations around the Thames and Medway Estuaries to enable transport of dense phase CO_2 to storage sites in the SNS Basin. In line with the Guidance, it is not assumed in this CCR study that the transport of captured CO_2 will be able to be outsourced to a hub or cluster such as the Thames Cluster, since the project must be considered without reliance on schemes that may not happen. In addition, it is understood that with the abandonment of the Kingsnorth CCS project (and the decommissioning and demolition of the power station) the proposals for this cluster have been withdrawn. However, if any updates are available in the future this option will be further reviewed as it could realise cost savings for CCS enabled projects in the region.

Figure 10: E.ONs proposed route of CO_2 pipeline from Thames Cluster[19]

After traversing the Peninsula, the off shore pipeline would run north east, past the site of the London Array wind farm, before turning north wards to run parallel to the east coast before linking in with the Hewett or Leman storage sites, discussed in Section 6. The pipeline corridor for this route is shown in Figure 9 and has been developed based on desk top mapping. Options for a pipeline corridor via Damhead Creek and Long Reach are also illustrated on this Figure.

7.1 Predominantly Onshore Transport prior to transition

The pipeline would run a relatively short distance (around 6km) on shore before the transition point, such is the proximity of the Proposed Development to the coast. This will reduce the range of onshore regulatory, safety and environmental issues which may arise. Physically there are few barriers to cross between the Proposed Development and the Thames Estuary via the Peninsula although there is a rail line and the A228, plus several minor roads.

The area surrounding the Proposed Development has a number of environmental constraints including the Medway Estuary and Marshes Special Protection Area (SPAs); Site of Special Scientific Interest (SSSI); and, RAMSAR site. For these reasons, it is proposed that the internationally designated sites are not crossed by any CO_2 pipeline, although this may be reconsidered at the detailed design phase, to evaluate the cost-benefit of using engineering options such as directional drilling or thrust boring techniques which avoid the need for trenching and may mitigate any environmental impacts on the designated sites. Alternative options that could be considered to mitigate the impact on protected wildlife species include timing the construction around migration patterns and breeding seasons or the use of relocation programmes for certain species and habitats away from any pipeline route.

Any pipeline routing for future carbon dioxide transport would be evaluated and determined as part of a route selection study and an Environmental Impact Assessment (EIA) for the future CCS installation. As part of that EIA process, any significant environmental impacts would be mitigated through use of appropriate pipe-laying methods and timings. With appropriate surveying of the routes within an agreed corridor and use of directional drilling techniques during specific seasons to avoid impacts on wintering or nesting birds, as appropriate, it is considered that an appropriate route can be identified and a pipeline can be constructed such that potential environmental impacts could be mitigated.

In addition, in the Yorkshire and Humber region, National Grid has submitted a Development Consent Order to develop a hub to transport carbon dioxide from multiple power stations and heavy industry to storage offshore. Developing networks where clusters of power stations or other heavy industry adopting CCS could use the same pipeline infrastructure would be much more practical and economic and minimise environmental impacts compared to each installation building its own separate pipeline, although connection to the hub termination point would still be required for each development.

[19] Camco (January 2011) CCS Strategy and Action Plan for the Greater South East

7.2 Predominantly Offshore Transport

It is noted that there may be some potential barriers which exist for the off shore pipeline corridor between the proposed transition points and the storage areas. These include: passing through environmentally sensitive wetlands; wind farm sites and associated cabling; dredging areas; shipping lanes; existing pipeline infrastructures; and, disposal sites.

A sub-sea pipeline in the estuary would typically be laid using specialist trenching and laying barges at low tide or low current periods to minimise disruption. Where the level of disruption to the environmentally sensitive areas (which is typically caused by trenching) is deemed to be unacceptable, other techniques such as thrust boring or directionally drilled boreholes may be feasible. Both boring methods avoid the need to disturb existing habitats and are typically employed in environmentally sensitive areas. Again, if these alternative boring techniques are not feasible it may be possible to plan activities around breeding and migration seasons, or consider species and habitat relocation. This would be established at the detailed design and EIA stage of the CCS development in the future.

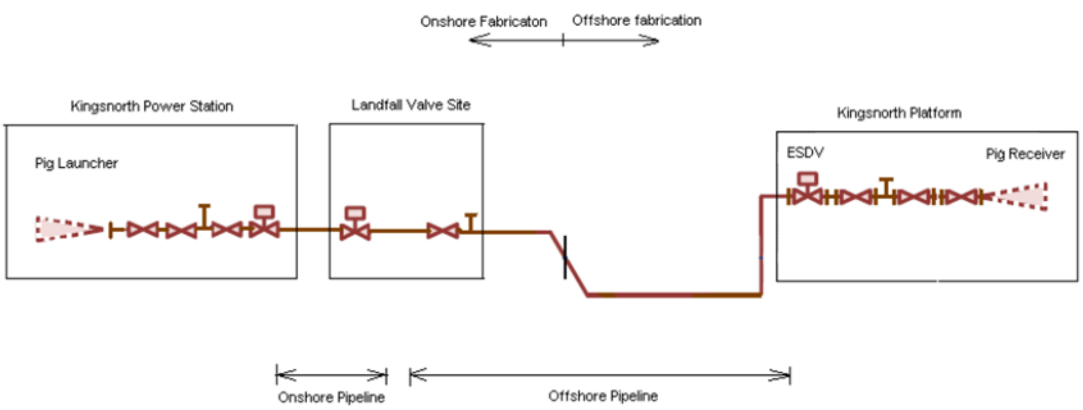
In addition, navigation of wind farm sites and associated cabling, dredging areas, existing pipeline infrastructures and disposal sites via the proposed route would be feasible. There is currently sufficient space between such sites to allow for the installation of a pipeline within the specified pipeline corridor on **Figure 9**. Experience gained by the natural gas and oil industry in laying pipelines in the SNS Basin would provide the techniques and expertise required to accomplish this. The routes of shipping lanes are not anticipated to be a significant barrier to this form of transport, because the pipeline would run along the seabed at a depth sufficient enough to allow ships to pass freely over.

In the future, options for this pipeline route may be further reduced due to the development of new restricted areas, such as new wind farm sites. Such issues would have to be taken into consideration at the time of future CCS deployment.

The impacts of the offshore CO_2 pipeline would be minimised by keeping the route of the pipeline a sufficient distance away from the shore so as not to impact any designated coastline.

It is considered that a feasible route exists to remove the captured CO_2 from DHC2 to either of the storage sites identified.

7.3 Kingsnorth Coal Fired Plant – Carbon Capture, Transport and Storage

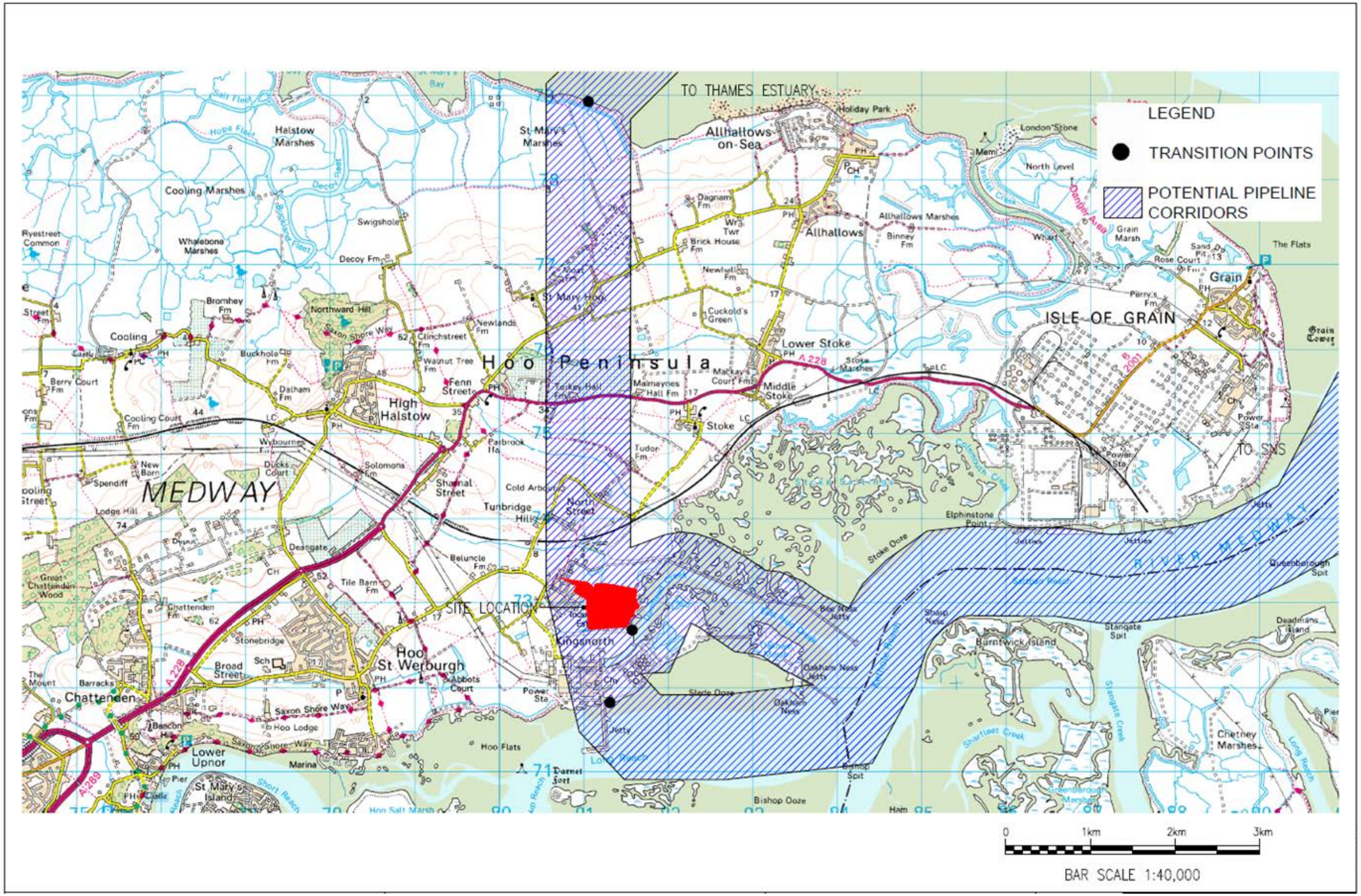


E.ON UK had previously considered investing in a new super-critical coal fired power plant at Kingsnorth, where captured CO_2 would be transported and stored in the Hewett gas field, approximately 40 km east of Bacton and approximately 270 km from Kingsnorth/Damhead Creek 2.

CO_2 would be captured, compressed and dried at Kingsnorth before being transported in a new 900mm diameter pipeline to a new offshore platform above Hewett gas field. It was assumed by E.ON that the CO_2 would remain in a gaseous state (<73bar) and therefore would not require a booster pumping station. However, a smaller diameter pipeline would be achievable if dense phase CO_2 were transported as it currently proposed for DHC2. In such a design, there may be need for a pumping station to be installed at the landing point before the pipeline is sent off-shore. This would be evaluated and sized at the detailed design stage and consented at the same time as the consenting of the onshore pipeline itself.

Ref: E.ON (2011) - Kingsnorth CCS Project - Basis of Design for Studies - Phase 1A

Figure 9: On Shore / Near Shore Pipeline Routes



8. Economic Assessment – Retrofitting Carbon Capture Technology, Transport and Storage

The principal economic driver currently available for CCS viability without Government fiscal support is the price of carbon. The price of carbon needs to have achieved a high enough monetary value to make carbon capture and storage economically viable. The carbon market remains very volatile and indeed some of its leading proponents are questioning the success of the system in delivering value for money carbon reductions.

However, regulation and financial incentives are two other options to assist with the development of carbon capture technology after the initial demonstration phase. While the current Emissions Performance Standard (EPS) is set at a level that does not require the use of CCS on efficient new build gas-fired power stations (450g/kWh at baseload), this may change in the future as both the EU and the UK Government continue to aspire to decarbonise electricity generation.

These issues are however beyond the control or scope of the DHC2 development. The Applicant therefore proposes to draw on existing economic modelling developed over a number of sites. Such modelling provides indications of the likely range of costs associated with the introduction of CCS facilities. These models include fuel price; carbon price; capture costs; transport costs and storage costs. Models have also looked at Enhanced Oil Recovery projections; network supported projections and variations around re-use of existing assets or construction of new assets. There is also the probability that costs will diminish as implementation moves from demonstration to roll out of installed capacity.

The 2011 "*CCS Strategy and Action Plan for the Greater South East'* prepared by Camco for the South East England Development Agency (pg.28) suggested the following costs for CCS:

- Capture = £35/tCO_2
- Onshore Transport = £4/tCO_2
- Offshore Transport = £6/tCO_2
- Offshore Storage in Oil and Gas Fields = £12/tCO_2
- Total: £57/tCO_2

The overall view at present suggests that:

- CCGT capital costs without carbon capture will be in the range of £400 – £600 per kW;
- With CCS, costs will be in the range of £1,000 – £1,800 per kW;
- The cost of carbon capture, transport and storage is anticipated to be £50/ tonne - £70/ tonne

In accordance with the CCR guidance using the information available the following have been compared to assess the economic feasibility of operational CCS at DHC2, as shown in Table 8-1:

a) Cost of electricity generation without CCS (and assuming that EU Allowances must be purchased for 100% of the CO_2 emitted by the Proposed Development and no free allowances are allocated); with

b) Worse case cost of electricity generation with CCS (including cost of retrofitting carbon capture equipment, cost of CO_2 transport and cost of CO_2 storage).

Table 8-1: Economic Feasibility of Operational CCS

Costs / £ per tonne CO_2	Scenario A – current carbon price		Scenario B – required carbon price	
	No CCS	CCS	No CCS	CCS
Carbon Allowances[20]	26[21]	N/A	57	N/A
Retrofitting capture equipment (construction and operation)	N/A	35	N/A	35
CO_2 Transport predominantly via pipeline	N/A	10	N/A	10
CO_2 Storage	N/A	12	N/A	12
Total Cost	**26**	**57**	**57**	**57**

Based on data obtained from the Kingsnorth, Longannet and Peterhead carbon capture competition publicly available documents, the capital cost of full chain CCS is £1.1-1.3 billion (based on 300 MW). Based on a scaling per tonne of captured CO_2 and considering the pipeline length to the proposed storage location, a capital cost of circa £1.2-1.6 billion is estimated for DHC2 assuming up to 140 Mt of CO_2 captured. In addition, the operating and pumping costs of the CCS plant and pipeline add up to the £57/t estimate presented in the Camco report. The costs estimates for CCS construction and operation at DHC2 are considered to be comparable to those of other CCS projects in the region; the length of offshore pipeline to the storage location representing one of the highest costs – and uncertainties – of the full CCS chain.

The information presented above confirms that the cost of electricity from DHC2 will be increased with the addition of CCS, due to the additional capital and operating costs of the carbon capture plant, pipeline and injection; this of course is to be expected. The results also indicate that the addition of CCS at the Proposed Development only starts to potentially become economically feasible at a cost of carbon in excess of £57/tonne and that assumes that the capital costs can be spread over 35 years of CO_2 capture at high load factors; for lower load factors on the CCGT the volume of CO_2 captured over the plant lifetime is correspondingly reduced, rendering the cost per tonne of CO_2 correspondingly higher. Therefore should the load factors for example drop from 90% (yielding up to 140 Mt CO_2) to 35% over the plant lifetime, this would reduce the captured CO_2 volumes to 54 Mt, which in turn would increase the lifetime CCS costs per tonne by a factor of 2.6. Similarly, a 60% load factor would yield 93Mt of CO_2 for storage which would increase the lifetime CCS costs per tonne by a factor of 1.5.

The above cost estimates also compare to the economic assessment undertaken for the 2009 DHC2 CCR Feasibility Study where an economic model was constructed to calculate the lifetime cost of electricity, expressed in terms of £/MWh, over the 35 year lifetime of the Proposed Development. This determined that the Proposed Development potentially became economically feasible with the addition of CCS at carbon prices of €125 (£94)/tonne and €75 (£56)/tonne using 2009 prices and projected 2020 prices respectively (i.e. the price of carbon required such that the cost of electricity over the life of the Proposed Development fitted with CCS remains the same value as that for the Proposed Development without the addition of CCS).

Comparable models developed for other power station developments in the UK to date have also utilised lifetime electricity costs, 100% carbon purchase assumptions and varying ranges of CO_2 cost from £0/tonne - £135/tonne. In these models, variation ("stressing") is added to fuel pricing, capital costs and baseline costs for transport and storage. Similar models have been utilised for the Carbon Capture and Storage Network for Yorkshire and Humber transport network solution study and the 'Opportunities

[20] EU Allowances under the EU Emissions Trading Scheme (EU ETS) / UK Carbon Floor Price

[21] Assuming £8/tonne EU ETS carbon cost and £18/tonne UK Carbon floor price

for CO_2 Storage around Scotland' study. These all confirm that the cost of carbon needs to be in excess of £57/tonne for full economic feasibility, rising beyond that if low load factors are taken into account.

These prices can be readily compared with data from external forecasters, e.g. the independent McKinsey Report "Pathways to a Low Carbon Economy" (2009) and the "Cost Abatement Curve". In particular Exhibit 8.1.4 of the McKinsey Report indicated an abatement cost of 50 Euros per tonne CO_2 for a gas CCS new build (by 2030), again assuming higher load factors are taken into account. Over time, it is anticipated that the required price of carbon may reduce toward the order of 50 Euros per tonne (predicted by external forecasters) as knowledge of carbon capture technology and full chain CCS advances, however, currently there are uncertainties as to rate of progression along that learning curve. It is considered that in the future some form of direct fiscal support for carbon capture facilities may be required in place, e.g. a Contract for Difference, capital grants, soft loans on favourable terms, etc.

Significant variances in modelled economic viability can occur as a result of fluctuations in:

- The selected load factor for the proposed power station (with around 18% variance in different models);
- Fuel prices, which exhibit -20% to +30% variance;
- Capital costs, which exhibit a 10% variance; and
- A potential 10% – 20% increase in fuel consumption costs to power the future CCS system.

The variables are substantial and are prone to external force variance. However, it is clear that there is a stronger viability if a CCS network is developed, utilising redundant existing pipeline and injection assets wherever possible. By developing a transport asset for a network, considerable costs are shared, and financing is potentially more readily available, as a number of partners share the risk and the opportunity. Some reports suggest that shared storage sites would also bring storage costs down by one third; although storage costs are expected to represent only approximately 10 – 24% of total costs.

These significant variance levels further serve to demonstrate the early risks associated with the current level of technology development and lead to economic viability assessments in excess of £57/tonne.

As outlined above, a key measure within the Energy Bill is the Emissions Performance Standard (EPS) which places a duty on operators of new fossil fuel generating stations to ensure their plants do not exceed an annual CO_2 emissions limit of 450g / kWh at baseload operation. (A 40% reduction compared to current typical coal fired plant). DECC acknowledges that the EPS of 450g/kWh at baseload may be reduced in future. However, as announced February 2013, the Energy Bill will 'grandfather' the EPS for plants that have been consented, under construction or operational by 2015. As such, until 2045, plants that can achieve the current EPS limit of 450g/kWh when consented (i.e. including the Proposed Development, which achieves less than 400 g/kWh) will be unaffected by future changes in the EPS. Therefore it is likely that the requirement to retrofit CCS in order to achieve an EPS of <450g/kWh will not apply to the Proposed Development until at least 2045.

A number of financial institutions (Deutsche Bank, New Carbon Finance, UBS) expect the price of carbon to be at £30/tonne – £35/tonne by 2030. At this stage, analysts anticipate the cost of carbon capture to have dropped by up to 50% if First Of A Kind deployment has taken place by then. This is thought to lead to a cost in the region of £28/tonne – £35/tonne of CO_2 abated in 2030. If these two factors do coincide then the cost of carbon capture will have reached a neutral position for the Proposed Development and similar CCGTs.

The study 'Opportunities for CO_2 Storage around Scotland' concludes that Government support in the region of £100m/year is required to develop the carbon capture, transport and storage facilities, to move this technology from demonstration to full implementation (dependent on the price of carbon). This is therefore the level of financial support considered by this study to be necessary if the industry is to move from concept to practical, economic implementation.

An important feature of an economic carbon transport system will be a network pipeline solution. Assessments estimate that the cost of shipping carbon would be in the range of £7.4/tonne – £8.6/tonne. Transporting carbon via pipeline would cost £1.9/tonne – £3.7/tonne based on a network capable of handling 20 million tonnes per annum. A single point-to-point pipeline would cost in the order of 30% more. Additionally, reaching a point of economic viability will require new alliances of businesses across the CCS supply chain.

In summary, deployment of CCS will add significant cost to both the capital outlay and the operation of any power station and currently is not considered to represent BAT for the Proposed Development. However, subject to market conditions, based on high level assumptions, the Proposed Development can in principal achieve an economically viable carbon capture solution if required in the future, as the site:

- Has sufficient space allocated and reserved for the potential retrofit of CCS if required;
- Has access to potentially secure geological carbon storage facilities that have capacity for the foreseeable future.

Should CCS technology be commercially deployed across the UK in the future, the proximity of the DHC2 site to other operational and proposed power generation facilities and industrial CO_2 emitters may also mean that a transport hub could be employed for the region, further reducing the CO_2 transport costs associated with this Proposed Development in isolation.

The assessment therefore demonstrate that there are no known economic barriers to capture, transport and storage of emissions of CO_2 from the Proposed Development and that Carbon Capture and Storage (CCS) technology could theoretically be retrofitted at a later date.

9. Health and Safety Assessment

It is likely that the onshore and offshore CO_2 transport from the site will be in a 'dense phase', i.e. at a pressure greater than 73.9 bar.

9.1 Pipeline

The DECC CCR Guidance Note states that, until the Health and Safety requirements of pipelines conveying dense phase CO_2 have been considered in more depth, such pipelines should be considered as conveying 'dangerous fluids' under the Pipeline Safety Regulations 1996 (PSR), and 'dangerous substances' under the Control of Major Accident Hazards Regulations 1999 (as amended) (COMAH). The pipeline would therefore be considered to be a Major Accident Hazard Pipeline (MAHP).

Therefore, when undertaking the detailed design of the pipeline route, it is recognised that the pipeline operator must pay due attention to the following potential requirements:

- Installation and frequency of emergency shut-down valves;
- The preparation of a Major Accident Hazard Prevention Document (MAPD); and
- Ensuring the appropriate emergency procedures, organisation and arrangements are in place.

In addition, the Local Authority, which has been notified by HSE of a MAHP, must prepare an Emergency Plan.

It is considered that – based on the evaluation undertaken on behalf of National Grid for the consenting of the White Rose carbon pipeline – the H&S implications and risks of any dense phase carbon pipeline can be appropriately mitigated through the routing and design of the pipeline. Similarly, based on hazard release modelling of comparable CO_2 compression facilities, potential accident scenarios can be evaluated and potentially significant effects can be mitigated; these would be undertaken at the detailed design phase of any CCS transport network.

9.2 On Site

There is the potential for dense phase CO_2 to be present on site once it has been captured and compressed prior to transport. Whilst CO_2 is not currently classified as hazardous, DECC and the HSE recognise that an accidental release of large quantities of CO_2 could result in a major accident (Ref.7).

It is understood that CO_2 may be reclassified as a hazardous substance in the near future. While the storage thresholds requiring HSC or COMAH licensing are not yet established, it is understood that thresholds of 50 tonnes for HSC or 1,000 tonnes for COMAH could be applied, although lower quantities may also be considered.

No storage of dense or gaseous phase CO_2 is proposed in the initial CCS design for the Development. The only 'stored' CO_2 on site would therefore be the inventory in the capture plant and on-site pipework, and this is envisaged to be considerably less than five tonnes. On this basis therefore, it is concluded that even if CO_2 were to be reclassified in the future, utilising the carbon capture technology selected for the Proposed Development (post-combustion capture based on amine based solution), the proposed design for DHC2 power station would not fall under the HSC regime.

10. Review

The Applicant is committed to review and report on the effective maintenance of the DHC2 CCR status within three months of the power station commencing commercial operations and periodically every two years thereafter.

Limitations

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The methodology adopted and the sources of information used by AECOM in providing its services are outlined in this Report. The work described in this Report was undertaken between December 2015 and January 2016 and is based on the conditions encountered and the information available during the said period of time. The scope of this Report and the services are accordingly factually limited by these circumstances.

Where assessments of works or costs identified in this Report are made, such assessments are based upon the information available at the time and where appropriate are subject to further investigations or information which may become available.

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Where field investigations are carried out, these have been restricted to a level of detail required to meet the stated objectives of the services. The results of any measurements taken may vary spatially or with time and further confirmatory measurements should be made after any significant delay in issuing this Report.

Annex A – Carbon Capture Technology

Annex A Carbon Capture Technology

Currently there are three types of carbon capture technology being developed, namely:

- Oxy-combustion carbon capture;
- Pre-combustion carbon capture; and
- Post combustion carbon capture.

Each technology was considered as part of the design evolution leading to the current proposal for the Development. Each option is discussed in turn as follows.

A.1. Oxy-combustion Carbon Capture

This process involves burning fossil fuels in pure oxygen as opposed to air, resulting in a more complete combustion. This results in an exhaust stream which consists of almost pure CO_2 (typically 90%) and water vapour, which can be separated from the CO_2 by condensation.

The main problem with this method is separating oxygen from the air. This is usually completed cryogenically which requires a lot of energy (for a typical 500MW power station, supplying pure oxygen requires at least 15% of the electricity the plant generates annually). In addition there is very limited knowledge regarding this technology on a commercial scale. The use of oxy-combustion carbon capture for the Proposed Development has therefore been discounted at this stage.

A.2. Pre-combustion Carbon Capture

Pre-combustion capture involves removal of CO_2, prior to combustion, to produce hydrogen. Hydrogen combustion produces no CO_2 emissions, with water vapour being the main by-product. The capture process consists of three stages; firstly the hydrocarbon fuel (typically methane, or gasified coal) is converted into hydrogen and carbon monoxide (CO) to form a synthesis gas. The second step is to convert the CO into CO_2 by reacting it with water. Finally, the CO_2 is separated from the hydrogen, which can then be combusted cleanly. The CO_2 can then be compressed into liquid and transported to a storage site.

The option of developing an Integrated Gasification Combined Cycle plant (IGCC) with pre-combustion carbon capture was considered as part of the early feasibility study for the project, however was discounted for the following reasons:

- This method is normally applied to coal-gasification combined cycle power plants;
- The pre-combustion method cannot easily be retro-fitted to existing power plants and an additional chemical plant is required in front of the gas turbine;
- The efficiency of H_2 burning turbines is lower than conventional gas turbines; and
- The costs associated with installation of an IGCC are considerably higher than the installation of a post-combustion plant.

A.3. Post combustion Carbon Capture

In post combustion carbon capture, CO_2 can be captured from the exhaust of a combustion process by absorbing it in a suitable solvent. The absorbed CO_2 is then liberated from the solvent and is compressed for transportation and storage. Other methods for separating CO_2 include high pressure membrane filtration, adsorption/ desorption processes and cryogenic separation.

The design chosen for the Development is high efficiency, natural gas-fired Combined Cycle Gas Turbine (CCGT) units with post combustion carbon capture. The advantages of post combustion carbon capture over the other carbon capture technologies available are as follows:

- Post combustion can feasibly be retrofitted to existing power stations without significant modifications to the original plant;
- Post combustion is the type of technology favoured by the UK Government in its competition to build one of the world’s first commercial scale CCS power plants in the UK;
- Post combustion carbon capture technology is the most developed and closest to commercial deployment at present.

Therefore, the feasibility of CCS for the Development has been assessed on the basis of the best currently available post combustion carbon capture technology, which, for carbon capture from flue gases is using amine based solution as CO_2 solvent. However the use of the alternative (pre-combustion or oxyfiring) technologies will not be excluded from future consideration as they may become viable at the time when the plant will have to be retrofitted with CCS.