The Drax Power (Generating Stations) Order

Land at, and in the vicinity of, Drax Power Station, near Selby, North Yorkshire

Carbon Capture Readiness Statement

(Submitted for Deadline 7)

The Planning Act 2008
The Infrastructure Planning (Applications: Prescribed Forms and Procedure) Regulations 2009 – Regulation 5(2)(q)

Drax Power Limited

Drax Repower Project

Applicant: DRAX POWER LIMITED
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Glossary and Abbreviations

The updated Glossary and Abbreviations for the Proposed Scheme are contained in Document Reference 1.6 submitted in November 2018 at Deadline 3 of the Examination.

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EXECUTIVE SUMMARY

1. This Carbon Capture Readiness (CCR) Statement has been prepared by WSP UK Limited on behalf of Drax Power Limited (Drax or the Applicant) to support an Application for a Development Consent Order (DCO).

2. The second revision of the CCR Statement was prepared to include the following updates:

- Response to changes requested by the EA in their Relevant Representation following acceptance of the application.
- Removal of the Site Reconfiguration Works / Stage 0 from the DCO.

3. The third revision of the CCR Statement has been prepared to include the following updates:

- Response to changes requested by the EA in accordance with further discussion with the Applicant.

4. The Applicant is proposing to repower up to two existing coal-fired units (known as Unit 5 and Unit 6) with gas – this means the existing coal-fired units would be decommissioned and replaced with newly constructed gas-fired units utilising some of the existing infrastructure. Each unit, which is a new gas fired generating station in its own right, and are termed Unit X and Unit Y, would comprise combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) technology. Each new gas generating unit would use existing infrastructure, including the cooling system and steam turbines, and would each have a new capacity of up to 1,800 MW, replacing existing units each with a capacity of up to 660 MW. Each unit would also have a battery storage capability (subject to technology and commercial considerations). Should both units be repowered, the new gas-fired units / generating stations would have a combined capacity of up to 3,800 MW.

5. The Applicant is seeking consent for the flexibility to either repower one unit (i.e. construct a single generating station known as Unit X) (with up to 1,800 MW generating capacity and battery storage capacity) or to repower two units (two generating stations (Unit X and Unit Y) each with an up to 1,800 MW generating. The decision as to whether Drax repowers two units and constructs two gas fired generating stations as opposed to a single unit is a commercial decision that can only be taken post any consent being granted.

6. A connection to the electrical network via the existing National Grid (NG) Substation on the Power Station Site will be provided.

7. In order to repower to gas, a new Gas Pipeline needs to be constructed from Drax Power Station to the National Transmission System (NTS).

8. The battery storage is not a thermal power plant producing waste heat, and so is not suitable for inclusion in the Combined Heat and Power (CHP) Assessment (document reference 5.6).

9. In line with the requirements of the Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 (Ref. 1.1), this CCR Statement has been prepared to support the DCO Application.

10. With regards to the requirement for a CCR Statement, the European Union (EU) agreed the text of the Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) (the Carbon Capture and Storage (CCS) Directive) on 17 December 2008 (Ref.1.2). This text was published in the Official Journal of the EU on 5 June 2009 and the CCS Directive came into force on 25 June 2009.

11. The CCS Directive requires an amendment to Directive 2001/80/EC on the limitation of emissions of certain pollutants from large combustion plants (commonly known as the Large Combustion Plant Directive (LCPD) (Ref. 1.3). Consequently, EU Member States are required to ensure that operators of all combustion plants with an electrical power generating capacity of 300 MW or more (and for which the construction / operating licence was granted after the date of the CCS Directive) have assessed whether the following conditions are met in respect of each combustion plant:

- Suitable storage sites for CO_2 are available;
- Transport facilities are technically and economically feasible; and
- It is technically and economically feasible to retrofit the combustion plant for CO_2 capture.

12. The assessment of whether these conditions are met is to be submitted to the relevant competent authority, who will use the assessment (and other available information) in their decision-making process in respect of consent for each combustion plant. If the conditions are met, the competent authority is to ensure that suitable space is set aside for the CO_2 capture technology necessary to capture and compress CO_2 from the combustion plant.

13. In the UK, the relevant competent authority (in respect of applications for consent on energy matters) is the Department for Business, Energy and Industrial Strategy (BEIS). BEIS must ensure the requirements of the relevant EU Directives are implemented and their transposition into domestic law. BEIS may also impose more stringent regulations within the UK. In giving effect to this, the UK Government has published the CCR Guidance (Ref. 1.4).

14. As part of an application for consent, the CCR Guidance states that applicants will be required to demonstrate:

- *"that sufficient space is available on or near the site to accommodate carbon capture equipment in the future;*
- *the technical feasibility of retrofitting their chosen carbon capture technology;*
- *that a suitable area of deep geological storage offshore exits for the storage of captured* CO_2 *from the proposed power station;*
- *the technical feasibility of transporting the captured* CO_2 *to the proposed storage area; and*
- *the likelihood that it will be economically feasible within the power station's lifetime, to link it to the full CCS chain, covering retrofitting of carbon capture equipment, transport and storage".*

15. Further to this "*if applicants' proposals for operational CCS involve the use of hazardous substances, they may be required to apply for Hazardous Substances Consent (HSC). In such circumstances, they should do so at the same time as they apply for [development consent under the Planning Act 2008]"* (Ref.1.5).

16. Based on the CCR Guidance requirements, it is considered that the information provided in this CCR Statement has successfully demonstrated that:

- Sufficient space is available to accommodate the proposed CO_2 capture technology associated with generating stations with an electrical generating capacity of up to 1,800 MW (Unit X) or up to 3,600 MW (Unit X and Unit Y);
- It will be technically feasible to retrofit and integrate the proposed CO_2 capture technology;
- There are suitable offshore CO_2 storage areas available;
- It will be technically feasible to transport the captured CO_2 to the offshore CO_2 storage areas; and
- It may be economically feasible, within the lifetime of Unit X and Unit Y, to implement the proposed CO_2 capture technology (including transport and storage).

17. Accordingly, it is considered that the DCO Application complies with the requirements of the CCR Guidance.

1 INTRODUCTION

1.1. Overview

1.1.1. This Carbon Capture Readiness (CCR) Statement has been prepared by WSP UK Limited on behalf of Drax Power Limited (Drax or the Applicant), to support an Application for a Development Consent Order (DCO). The second revision of the CCR Statement was prepared to include the following updates:

- Response to changes requested by the EA in their Relevant Representation following acceptance of the application
- Removal of the Site Reconfiguration Works / Stage 0 from the DCO.

1.1.2. This third revision of the CCR Statement has been prepared to include updates in response to changes requested by the EA in with further discussions with the Applicant.

1.1.3. The Applicant is proposing to repower up to two existing coal-fired units (known as Unit 5 and Unit 6) with gas – this means the existing coal-fired units would be decommissioned and replaced with newly constructed gas-fired units utilising some of the existing infrastructure. Each unit, which is a new gas fired generating station in its own right, and are termed Unit X and Unit Y, would comprise combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) technology. Each new gas generating unit would use existing infrastructure, including the cooling system and steam turbines, and would each have a new capacity of up to 1,800 MW in combined cycle operation, replacing existing units each with a capacity of up to 660 MW. Each unit would also have a battery storage capability (subject to technology and commercial considerations). Should both units be repowered, the new gas-fired units / generating stations would have a combined capacity of up to 3,800.

1.1.4. The Applicant is seeking consent for the flexibility to either repower one unit (i.e. construct a single generating station known as Unit X) (with up to 1,800 MW generating capacity and battery storage capacity) or to repower two units (two generating stations (Unit X and Unit Y) each with an up to 1,800 MW generating capacity and each with its own battery storage capacity. The decision as to whether Drax repowers two units and constructs two gas fired generating stations as opposed to a single unit is a commercial decision that can only be taken post any consent being granted.

1.1.5. A connection to the electrical network via the existing National Grid (NG) Substation on the Power Station Site will be provided.

1.1.6. In order to repower to gas, a new Gas Pipeline needs to be constructed from Drax Power Station to the National Transmission System (NTS).

1.1.7. The battery storage is not a thermal power plant producing waste heat, and so is not suitable for inclusion in the Combined Heat and Power (CHP) Assessment (document reference 5.6).

1.2. The Purpose of this Document

1.2.1 The UK Government publishes criteria for which applications to construct and operate electricity generating stations are considered.

1.2.2 In terms of applications for a DCO, the UK Government has published CCR Guidance which applies to applications for consent for power plant with an electrical generating capacity at or over 300 MW and of a type covered by the European Union (EU) Directive on the limitation of emissions of certain pollutants from large combustion plants (commonly known as the Large Combustion Plant Directive or LCPD) (Ref 1.3).

1.2.3 In line with the requirements of the CCR Guidance, this CCR Statement has been prepared to support the application for a DCO.

1.3. The Structure of this Document

1.3.1 This document comprises:

Introductory Information:

- Section 1 – This brief introduction.
- Section 2 – The context and assessment methodology.
- Section 3 – A description of the Drax site.

CO_2 Capture Technology Information:

- Section 4 – A description of the proposed CO_2 capture technology (i.e. post-combustion CO_2 capture technology).

Technical Assessments:

- Section 5 – The technical assessment of the CO_2 capture technology space.
- Section 6 – The technical assessment of the retrofitting and integration of the CO_2 capture technology.
- Section 7 – The technical assessment of CO_2 storage areas.
- Section 8 – The technical assessment of CO_2 transport.

Economic Assessment:

- Section 9 – The economic assessment.

Additional Information:

- Section 10 – A discussion on the requirement for a Hazardous Substances Consent (HSC).

Conclusions:

- Section 11 – Conclusions of the CCR Statement.

Additional supporting information is provided in the Appendices, which comprise:

- Appendix 1 – Figures
- Appendix 2 – The relevant sections of the EU Directives.
- Appendix 3 – The CCR requirements checklist.
- Appendix 4 – Annex C of the CCR Guidance.

2 CONTEXT AND ASSESSMENT METHODOLOGY

2.1 Context

European Union

2.1.1. The EU agreed the text of the Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) (the Carbon Capture and Storage (CCS) Directive) on 17 December 2008 (Ref. 1.2). This text was published in the Official Journal of the European Union of 5 June 2009 and the CCS Directive came into force on 25 June 2009.

2.1.2. The CCS Directive requires an amendment to Directive 2001/80/EC on the limitation of emissions of certain pollutants from large combustion plants. Consequently, EU member states are required to ensure that operators of all combustion plants with an electrical power generating capacity of 300 MW or more (and for which the construction / operating licence was granted after the date of the CCS Directive) have assessed whether the following conditions are met in respect of each combustion plant:

- Suitable storage sites for CO2 are available;
- Transport facilities are technically and economically feasible; and
- It is technically and economically feasible to retrofit for CO2 capture.

2.1.3. The assessment of whether these conditions are met is then to be submitted to the relevant competent authority, who will use the assessment (and other available information) in their decision making process in respect of consent for each combustion plant. If the conditions are met, the competent authority is to ensure that suitable space is set aside for the CO_2 capture technology equipment necessary to capture and compress CO_2 from the combustion plant.

2.1.4. The relevant sections of the CCS Directive are attached in Appendix 2.

2.1.5. The requirement for such an assessment is also included in the more recent Directive on industrial emissions (integrated pollution prevention and control) (Directive 2010/75/EU) (the Industrial Emissions Directive or (IED) (Ref. 2.2). The relevant sections of the IED are also attached in Appendix 2.

UK Government

2.1.6. In the UK, the relevant competent authority (in respect of applications for consent on energy matters) is the Department for Business, Energy and Industrial Strategy (BEIS). BEIS must ensure the requirements of the relevant EU Directives are implemented. BEIS may also impose more stringent regulations within the UK. In giving effect to this, the UK Government has published the CCR Guidance.

2.1.7. To help transpose the CCR requirements as outlined in the IED into UK law, the Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 (Ref. 1.1) was enacted.

2.1.8. In accordance with the Planning Act 2008 (PA 2008) (Ref. 1.5), the Secretary of State (SoS) is required to determine an application for a DCO for an energy NSIP in accordance with the Overarching National Policy Statement for Energy (EN-1) (2011, DECC) (Ref. 2.2).

CCR Guidance Requirements

2.1.9. As part of an application for consent, the CCR Guidance states (at paragraph 7) that applicants will be required to demonstrate:

- *"That sufficient space is available on or near the site to accommodate carbon capture equipment in the future;*
- *The technical feasibility of retrofitting their chosen carbon capture technology;*
- *That a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from the proposed power station;*
- *The technical feasibility of transporting the captured CO_2 to the proposed storage area; and,*
- *The likelihood that it will be economically feasible within the power station's lifetime, to link it to the full CCS chain, covering retrofitting of carbon capture equipment, transport and storage".*

2.1.10. Further to this: *"if applicants' proposals for operational CCS involve the use of hazardous substances, they may be required to apply for Hazardous Substances Consent (HSC). In such circumstances they should do so at the same time as they apply for [a development consent order under the PA 2008]."*

2.1.11. If granted consent, the CCR Guidance states (at paragraph 8) that applicants / operators will be required to:

- *"Retain control over sufficient additional space on or near the site on which to install the carbon capture equipment, and the ability to use it for that purpose;*
- *Submit reports to the Secretary of State for Department of Energy and Climate Change (DECC) [now BEIS] as to whether it remains technically feasible to retrofit CCS to the power station".*

Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 Requirements

2.1.12. The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 transposes the IED into UK law.

2.1.13. Regulation 3 provides that the SoS must not make a development consent order unless the SoS has determined whether the CCR conditions are met in relation to the combustion plant to which the consent order relates.

2.1.14. Regulation 2 provides that the CCR conditions are met in relation to a combustion plant, if, in respect of all of its expected emissions of CO_2—

"(a) Suitable storage sites are available;

(b) It is technically and economically feasible to retrofit the plant with the equipment necessary to capture that CO_2*; and*

(c) It is technically and economically feasible to transport such captured CO_2 *to the storage sites referred to in sub-paragraph (a)."*

2.1.15. In accordance with regulation 3(2) the SoS's determination as to whether such conditions are met must be on the basis of:

"(a) A CCR assessment of the combustion plant prepared by the person who made the application for the relevant consent order; and

(b) Any other available information, particularly concerning the protection of the environment and human health."

2.1.16. Regulation 3(3) continues:

"If the Secretary of State -

(a) Determines that the CCR conditions are met in relation to a combustion plant; and

(b) Decides to make a relevant consent order in respect of that plant,

the Secretary of State must include a requirement in the relevant consent order that suitable space is set aside for the equipment necessary to capture and compress all of the CO_2 *that would otherwise be emitted from the plant."*

2.1.17. This assessment provides the necessary information to inform the SoS determination.

Overarching National Policy Statement for Energy (EN-1) Requirements

2.1.18. The requirement for the consideration and/or implementation of CHP, is detailed within section 4.7 Carbon Capture and Storage (CCS) and Carbon Capture Readiness (CCR) of EN-1.

2.1.19. Paragraph 4.7.10 of EN-1 states:

"To ensure that no foreseeable barriers exist to retrofitting carbon capture and storage (CCS) equipment on combustion generating stations, all applications for new combustion plants which are of generating capacity at or over 300 MW 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."

2.1.20. To assure that the Proposed Scheme is CCR, EN-1 states that the proposal shall comply with the CCR Guidance requirements (outlined above).

2.2 Assessment Methodology

2.2.1. Within this document, the following approach and assessment methodology was used to establish the requirements for both the scenario in which one unit is repowered and Unit X is constructed, and the scenario in which both units are repowered and Unit X and Unit Y are constructed:

- Step 1) Establish a high level design concept for the repowered units.
- Step 2) Establish the likely CO2 capture / storage requirement for the repowered units using modelling.
- Step 3) Identify a preferred CO2 capture technology for retrofit / integration to the repowered units, and the likely impact of the preferred CO2 capture technology on the performance of the repowered units was modelled.
- Step 4) Establish the size of the main CO2 capture plant / equipment using the above modelling and information from:
    - CO2 capture technology providers;

  - GTPro, GTMaster and Thermoflex software modelling of generic power plant with CO2 capture technology; and,
  - Excel based modelling of generic power plant with CO2 capture technology.
  - In the absence of technology / specific data, professional judgement was used to make various assumptions where required.
  - The sizing of the internal dimensions of the main CO2 capture plant / equipment has been based on information and a typical plant layout provided by Siemens for their PostCapTM CO2 capture technology. Using these dimensions, likely worst case estimates of the external dimensions of the main CO2 capture plant / equipment has been determined. The balance of plant items (heat exchanger, pumps, etc.) cooling plant/equipment are also based on the Siemens process layout.
  - The sizing of the auxiliary heat recovery steam generators (HRSGs) has been based on estimate sizing from Thermoflex software.

- Step 5) Preparation of an outline plot level plan (based on worst case plant operation mode) to confirm that the CO2 capture plant / equipment can be accommodated within the land currently available.
- Step 6) Identify CO2 storage areas with capacities to meet the CO2 storage requirement of the repowered units.
- Step 7) Identify preferred CO2 pipeline route corridors to transport captured CO2 from the repowered units to the CO2 storage areas.
- Step 8) Undertake an economic assessment to estimate the price of EU allowances for CO2 which were necessary to make the repowered units feasible with CO2 capture.

2.3 Verification of CCR

2.3.1. This document provides the information required by the CCR Guidance. A checklist of this information (with reference to the relevant requirements of the CCR Guidance) is provided in Appendix 3.

2.3.2. The CCR Guidance states that BEIS will be advised by the Environment Agency (EA) whether the submitted information meets the relevant requirements of the CCR Guidance. The EA will provide its advice on the technical feasibility of a proposal based on Annex C of the CCR Guidance (Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station using Post-Combustion Solvent Scrubbing) (Ref 2.3). This Annex is provided in Appendix 4.

3 PROJECT DESCRIPTION

3.1 The Applicant

3.1.1. The Applicant is Drax Power Limited. Drax Power Station is owned and managed by the Applicant, who is part of the Drax Group Plc, one of the UK's largest energy producers.

3.2 Site Description

Existing Drax Power Station Complex

3.2.1. Drax Power Station is a large power station, comprising originally of six coal-fired units. It was originally built, owned and operated by the Central Electricity Generating Board and had a capacity of just under 2,000 MW when Phase 1 was completed in 1975. Its current capacity is 4,000 MW after the construction of Phase 2 in 1986.

3.2.2. Three of the original six coal-fired units are now converted to biomass (Units 1-3) and this is assessed as the current baseline in the Environmental Statement (ES) (document reference 6.1). Since August 2018, four units (Units 1-4) run on biomass with only two units (Units 5 and 6) running on coal. One or both of Units 5 and 6 will be repowered as part of the Proposed Scheme, this means the existing coal-fired units would be decommissioned and replaced with newly constructed gas-fired units utilising some of the existing infrastructure. The area within the Existing Drax Power Station Complex where development is proposed is referred to as the Power Station Site and is approximately 46.01 ha.

Pipeline Area

3.2.3. The Gas Pipeline route is approximately 3 km in length and crosses agricultural land to the east of the Existing Drax Power Station Complex. The land within the Pipeline Construction Area is 25.4 ha and the land within the Pipeline Operational Area is 2.4 ha.

3.2.4. An additional area is located on Rusholme Lane (Rusholme Lane Area) to accommodate a potential passing place for traffic during construction of the Gas Pipeline. This is considered to be part of the Pipeline Area.

Site Boundary

3.2.5. The Site is approximately 71.4 ha and lies approximately 4 m Above Ordnance Datum (AOD).

3.2.6. The Site Boundary (depicted with a red line on the Site Location Plan (submitted at Deadline 2, Applicant's Examination Library Ref REP2-005)) represents the maximum extent of all potential permanent and temporary works required as part of the Proposed Scheme.

3.2.7. The Power Station Site, the Carbon capture readiness reserve space and the Pipeline Area (including the Rusholme Lane Area) have been divided into a number of Development Parcels shown on Chapter 1 (Introduction) Figure 1.3. of the ES (Examination Library Reference APP-069).

3.2.8. The current land uses at these development parcels are described in Table 3-1 of the ES Chapter 3 (Site and Project Description) (Examination Library Reference REP6-003).

3.3 The Proposed Scheme

3.3.1. The Proposed Scheme is to repower up to two existing coal-powered generating units (Units 5 and 6) at the Existing Drax Power Station Complex with new gas turbines that can operate in both combined cycle and open cycle modes. The term "repower" is used as existing infrastructure, such as the steam turbine and cooling towers, that are currently used for the coal fired units would be reutilised for the new gas fired generating units/stations.

3.3.2. The repowered units (which each constitute a new gas fired generating station) would have a new combined capacity of up to 3,600 MW in combined cycle mode (1,800 MW each), replacing existing units with a combined capacity to generate up to 1,320 MW (660 MW each).

3.3.3. Each gas generating station (or unit) would have up to two gas turbines, with each gas turbine powering a dedicated generator of up to 600 MW in capacity. The gas turbines in each generating station (or unit), therefore, would have a combined capacity of up to 1,200 MW. The gas turbines in each generating station (or unit), in combined cycle mode, would provide steam to the existing steam turbine (through Heat Recovery Steam Generators (HRSGs)) which would generate up to 600 MW per generating station (or unit). Each generating station (or unit) would have up to two HRSGs. This results in a capacity for each generating station of up to 1,800 MW and, should both Units 5 and 6 be repowered, a combined capacity of up to 3,600 MW. The new gas turbine generating stations (or units) have been designated the terms "Unit X" and "Unit Y".

3.3.4. Each of Unit X and Unit Y would have (subject to technology and commercial considerations) a battery energy storage facility. The two battery energy storage facilities would be enclosed or protected by a structure such as a shield or cladding.

3.3.5. The total combined capacity of the two gas fired generating stations, Unit X and Unit Y, and two battery storage facilities (i.e. the total combined capacity of the Proposed Scheme) is therefore 3,800 MW.

3.3.6. The DCO seeks consent for the following flexibility:

- Repowering of either Unit 5 or 6 and construction of Unit X as a gas fired generating station (this would leave either Unit 5 or 6 (depending on which had been repowered) as a coal-fired unit); or
- Repowering of both Units 5 and 6 and construction of Unit X and Unit Y as two gas fired generating stations.

3.3.7. In the single unit scenario, up to two gas turbines and up to two HRSGs and (subject to technology and commercial considerations) a battery energy storage facility would be constructed. The maximum size of the battery storage cells and any structure built to protect / shield them would not change, as the battery storage cells for one Unit could be one larger battery which would allow the output associated with one Unit to be sustained for a longer duration. However, the fuel gas station and gas insulated switchgear would be smaller.

3.3.8. In the event that two units are repowered and both Unit X and Unit Y are constructed, then construction works would be undertaken consecutively rather than concurrently. It is assumed for the purposes of the ES that there would be a gap of a year between construction periods, but this could be longer depending on commercial considerations. Unit Y would mirror Unit X, with up to two gas turbines and up to two HRSGs and (subject to technology and commercial considerations) a battery energy storage facility which may be included within, or shielded by, the structure, should one be constructed, protecting / shielding the battery for Unit X.

3.3.9. In order to repower to gas, a new Gas Pipeline would be constructed from the Existing Drax Power Station Complex to the National Transmission System (NTS) operated by National Grid. Pipeline infrastructure would be the same whether Unit X was constructed or whether Unit X and Unit Y was constructed.

3.3.10. A gas receiving facility (GRF) comprising Pipeline Inspection Gauge (PIG) Trap Facility (PTF), Pressure Reduction and Metering Station (PRMS) and compressor station is proposed south of woodland to the east of New Road.

3.3.11. At the connection to the NTS there will be an above ground installation (AGI) south of Rusholme Lane. The AGI involves a PIG Trap Launching station (PTF-L) which will be operated by Drax, and a Minimum Offtake Connection (MOC), which will be operated by National Grid.

3.3.12. The development being applied for is called the "Proposed Scheme" and is more fully described in Schedule 1 of the draft Development Consent Order (where it is termed the "Authorised Development"). A full project description is provided in the ES Chapter 3 (Site and Project Description) (Examination Library Reference REP6-003).

4 THE PROPOSED CCR CONFIGURATION AND CO_2 OUTPUT

4.1.1. As indicated previously, the Proposed Scheme will provide between 1,800 MW and up to 3,600 MW of net electrical generation capacity at typical site rated conditions.

4.1.2. The only output of the modelling process required for sizing of the CO_2 capture technology to be implemented are details of the CO_2 and flue gas flow rate and the temperature of the flue gas[1].

4.1.3. Internal power plant modelling exercises have been conducted by WSP UK Limited in order to determine CO_2 and flue gas intensity factors for different turbine technologies. These intensity factors have been used in this CCR Statement to estimate maximum and average CO_2 and flue gas flow rates for the repowered units.

4.1.4. The CO_2 and flue gas intensity factors were modelled assuming a power plant configuration of one multishaft CCGT unit for the up to 1,800MW case (i.e. Unit X alone) and two multishaft CCGT units for the up to 3,600MW case (i.e. Unit X and Unit Y). Values were determined for gas turbines and steam turbines with a triple pressure reheat steam cycle. The Proposed Scheme will also have the flexibility to operate in OCGT mode for up to 1500 hours per year, based on a 5-year rolling average.

4.1.5. For OCGT mode, the overall plant electrical output will be less than in CCGT mode but the operation of the gas turbine will essentially be unchanged and so the CO_2 emissions from the gas turbine flue gases in OCGT mode will be the same as in CCGT mode. As the CO_2 emissions from the plant are the same in both modes, the CO_2 intensity factor and the flue gas intensity factor will remain unchanged between modes of operation. This is because the intensity factors are determined per MW output of the gas turbine unit and so are not impacted by total plant electrical output varying between OCGT and CCGT modes.

4.1.6. The Siemens SGT5-9000HL has provisionally been selected as the gas turbine model for this plant. As this is a new machine, limited information is available to model the proposed plant within GT Pro. Modelling has therefore been completed for the Siemens SGT5-8000H which is the closest Siemens machine in output. A scale factor on output has been used for the results in Table 2, however it is likely the final numbers will be lower due to the increased efficiency of the Siemens SGT5-9000HL, and therefore the modelling results will be conservative.

4.1.7. Table 1 indicates the CO_2 and flue gas intensity factors and power ratios for the Siemens SGT5-8000H.

4.1.8. The power ratio is used to determine the maximum flow rates (using the average flow rates). The power ratio is the difference between the total electrical output at typical site rated conditions (10°C) and the total electrical output at reduced atmospheric temperature

[1] However, it should be noted that the temperature of the flue gas may be affected by some integration of the power plant with the CO_2 capture plant (e.g. flue gas cooling).

conditions[2] (5°C[3]). Accordingly, the power ratio is used to determine the maximum flow rates which could be expected from the repowered units under worst case conditions.

Table 1 – CO_2 and Flue Gas Intensity Factors for Siemens SGT5-8000H

	CO_2 Intensity (t/h/MW)	Flue Gas Intensity (t/h/MW)	Power Ratio
Siemens SGT5-8000H	0.339	5.157	1.003

4.1.9. The sizing of the CO_2 capture technology equipment will be undertaken using values in Table 1 for the Siemens SGT5-8000H, as applied to the maximum theoretical electrical output of Unit X and Unit Y, yielding the maximum possible CO_2 and flue gas flow rates. The CO_2 storage requirement will be estimated using the CO_2 and flue gas flow rates. Whilst the likely values for the parameters in Table 1 for the Siemens SGT5-9000HL will be lower, this approach will be undertaken such that there is a worst-case scenario presented in this document.

4.2 Factors that Affect the Size of the CCS Chain

4.2.1. The size of the CCS chain is driven by the quantity of CO_2 going through the CCS chain and the capture rate of CO_2.

4.2.2. There are two main options which will influence the sizing of the CCS chain for Unit X and Unit Y. These are referred to as Option A and Option B, and are related to the way steam is generated for the CO_2 capture technology equipment. In brief:

- Option A: Steam for the CO_2 capture technology equipment is taken from the steam cycle of Unit X and Unit Y.
- Option B: Steam for the CO_2 capture technology equipment is generated by auxiliary boilers.

4.2.3. If Option A was chosen, the initial design would have a larger impact on CCGT power plant efficiency when compared with Option B. The two design scenarios that could be adopted for Option A are:

- Scenario A1: A largely standard CCGT power plant design for Unit X and Unit Y is installed and then when required, CO_2 capture technology equipment is retrofitted into the design. For this scenario, the efficiency is good prior to the retrofit but then efficiency is reduced after.
- Scenario A2: A non-standard CCGT power plant design for Unit X and Unit Y is installed where more consideration is given to any future CO_2 capture equipment. For this scenario, the efficiency would not be as good as Scenario A1 prior to the retrofit but would be better than Scenario A1 after the retrofit.

[2] A lower atmospheric temperature will increase the total electrical output of electricity generating plant, and with this comes a corresponding increase in CO_2 flow rate.
[3] It should be noted that whilst ambient temperatures will fall below 5°C, this value was selected to simulate the effect of the anti-icing equipment on the gas turbine inlet air temperature.

4.2.4. Option B would require minimal changes to be made in terms of retrofitting when CO_2 capture technology equipment is installed. However, additional fuel would be required for the auxiliary boiler, which could in turn increase the size of the CCS chain if the additional CO_2 in the auxiliary boiler flue gases was combined with the flue gases from the CCGT power plant prior to entering the CO_2 capture technology equipment.

4.2.5. Whilst both Option A and Option B are potentially available for Unit X and Unit Y, Option A is the main focus of this CCR Statement as it is deemed the most feasible and so considered the preferred option. The reasoning for this has been included above but in summary, Option B will be more complex, more expensive, take up more space (since additional equipment is required), requires additional fuel and as such, results in more CO_2 having to be captured.

4.2.6. When the Proposed Scheme is operating in CCGT mode, steam will be available from the steam cycle. However, to continue operation of the CO_2 capture plant in OCGT mode, steam will be unavailable from the HRSGs and so will need to be provided from an alternative source. Summary of the three alternate steam generating sources is provided below:

- Option 1 – Gas fired auxiliary boilers: Produces additional CO_2 which would be required to be captured as part of CO_2 capture plant. Results in larger plant size.
- Option 2 – Electric auxiliary boilers: Requires auxiliary power from the power plant which reduces plant efficiency.
- Option 3 – Utilisation of the heat from the hot OCGT flue gas in an auxiliary HRSG: Does not produce additional CO_2 and does not require auxiliary power from the power plant. It also reduces the duty of the flue gas cooler and as such, cooling load.

4.2.7. At the time of writing this CCR Statement, Option 3 is considered the most suitable solution for generating process steam when the plant is operating in OCGT mode and as such, will be assumed for the CCR Statement. It is noted that an alternate process steam generating option may be more suitable at the time of implementing the CO_2 capture plant and so the final technology choice would be subject to detailed feasibility and design work at the appropriate time. When conducting the Technical Assessment for this CCR Statement, a combination of Scenario A1 (CCGT Operation) and Option 3 (OCGT Operation) will be assumed.

4.3 Size of the CCS Chain

4.3.1. It is expected that the CO_2 capture technology equipment eventually installed would capture up to 90% of the CO_2 in the flue gases. However, this value will be dependent upon the CO_2 capture technology and the process cooling available.

4.3.2. The sizing of the CCS chain (including CO_2 capture, compression / liquefaction, transport and storage) is based on the information presented in Table 2.

Table 2 – Sizing of CCS Chain for Option A

Component	Units	Average Amount – 1,800 MW Case	Average Amount – 3,600 MW Case
CO_2 in Flue Gas	kg/s	169.7	339.4
CO_2 Captured	kg/s	152.7	305.5

Component	Units	Average Amount – 1,800 MW Case	Average Amount – 3,600 MW Case
(assuming 90% Capture)	t/h	549.8	1,099.7
	t/day	13,196	26,392
CO_2 Stored (Assuming 75 percent lifetime capacity factor)	Mt/year	3.61	7.22
Total CO_2 Stored (Assuming 25 years of capture)	Mt	90.3	180.6

4.3.3. For a 1,800 MW plant (Unit X), the CCS chain should be capable of handling a maximum CO_2 flow rate of approximately 169.7 kg/s which may occur whenever Unit X is operating at full load. On this basis, the CCS chain should be capable of processing a maximum CO_2 flow rate of approximately 13,196 t/day.

4.3.4. For operation with Option A, with a 3,600 MW plant (Unit X and Unit Y), the CCS chain should be capable of handling a maximum CO_2 flow rate of approximately 339.4 kg/s which may occur whenever Unit X and Unit Y are operating at full load. On this basis, the CCS chain should be capable of processing a maximum CO_2 flow rate of approximately 26,392 t/day.

4.3.5. The total annual throughput for the CCS chain will vary, and be dependent upon the operational profile for Unit X and Unit Y. With a 75% lifetime capacity factor, the total amount of CO_2 to be stored over the lifetime of Unit X and Unit Y (expected to be 25 years) would therefore be approximately 90.3 Mt for a 1,800 MW plant (Unit X) or 180.6 Mt for a 3,600 MW plant (Unit X and Unit Y). The assessment is based on these assumptions.

4.3.6. As the CO_2 intensity factor and the flue gas intensity factor will remain unchanged between CCGT and OCGT modes of operation (Section 4.1.5), it can be assumed the rate of CO2 capture will not change between the two different modes of operation.

5 PROPOSED CO2 CAPTURE TECHNOLOGY

5.1 Current Understanding

5.1.1. Current understanding is that the CO_2 capture technology would not be installed until CO_2 capture is either mandated or economically and technically feasible.

5.1.2. A number of CO_2 capture technologies currently exist and, at the time of eventual installation, it is highly probable that the number of CO_2 capture technologies will have increased (as recognised by the CCR Guidance). However, this document focuses solely on the CO_2 capture technology that is closest to commercial deployment at present in order to demonstrate CCR.

5.1.3. As such, this document focuses on currently available CO_2 capture technology, rather than speculating on any future developments that may be available when the CO_2 capture technology is ultimately installed.

5.1.4. Therefore, the feasibility of CCR for the repowered units has been assessed on the basis of the best currently available technology, which, for CO_2 capture from flue gases (post-combustion CO_2 capture), is chemical absorption using amine solvents. The amine solvents are typically based on monoethanolamine (MEA), diamine or sterically hindered amine.

5.1.5. This CO_2 capture technology may be regarded as commercially available but has not yet been commercially proven for large-scale power plant applications above approximately 120 MW output. However, it is the belief of WSP UK Limited that no technical barriers exist for extending existing experience to a scale appropriate to the Proposed Scheme.

5.2 Post-Combustion CO_2 Capture Technology (using Amine Solvents)

5.2.1. The post-combustion CO_2 capture technology on which the technical assessments are based 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.

5.2.2. A schematic of the post-combustion CO_2 capture technology is provided in Figure 2 in Appendix 1 and a brief description is provided here.

5.2.3. For post-combustion, the flue gases are compressed then cooled in a direct contact cooler for processing in the CO_2 capture plant. When the plant is running in OCGT mode, a higher temperature flue gas will be sent to the CO_2 capture plant. To utilise the high temperature, it is proposed to send the flue gas through an auxiliary HRSG to produce the required process steam for the plant. The OCGT flue gas may require further cooling via the CCGT mode direct contact.

5.2.4. After cooling, the flue gas passes through an absorber column where it comes into contact with the liquid amine solvent.

5.2.5. In the absorber column, the CO_2 in the flue gas is chemically absorbed through acid-base neutralisation reactions with the amine solvent. This creates a CO_2 rich stream of liquid amine solvent. The CO_2 rich amine solvent is pumped out of the absorber column and is heated in a heat exchanger before entry into a stripper column.

5.2.6. In the stripper column, the CO_2 rich amine solvent is heated further by the condensation of steam in a reboiler. As the amine can absorb less CO_2 at higher temperatures, upon heating the amine solvent releases the CO_2 as a gas. The lean liquid amine solvent is pumped from the bottom of the stripper column, cooled in the heat exchanger and further cooled before re-entry to the absorber column.

5.2.7. The CO_2 gas, containing a large quantity of steam, exits at the top of the stripper column. It is cooled to remove the steam and compressed or liquefied for transport. Steam and water removed from the CO_2 stream are returned to the CO_2 capture plant.

5.2.8. This CO_2 capture technology can result in an end CO_2 purity of over 99% based on the experience from similar technologies in the chemical processing industry.

5.3 Discussion of CO_2 Capture Process Temperatures

5.3.1. If amine such as MEA is in contact with CO_2, the CO_2 will react with the amine and chemically absorb into it. The CO_2 capture process is driven by the fact that at lower temperatures more CO_2 will absorb into the amine than at higher temperatures. Therefore, in principle, CO_2 is absorbed by cold amine and released when the amine is heated.

5.3.2. In modern amine-based CO_2 capture processes, the stripper column operates at approximately 150°C. Temperatures higher than this will thermally degrade the amine. In theory, the absorber column can operate at any temperature below the stripper temperature. However, the larger the temperature difference between the two, the more CO_2 can be captured.

5.3.3. Indicative figures indicate an absorber column temperature of 35°C and a stripper column temperature of 150°C will enable a CO_2 capture rate of 90%. Actual values will depend on various other parameters of the CO_2 capture process, such as:

- The particular amine used;
- The CO_2 capture process temperature;
- The pressure in the absorber column and stripper;
- The residence time (i.e., the length of time the amine is in contact with the flue gas);
- The percentage of CO_2 in the flue gas; and,
- The amount of other substances.

5.3.4. The intended operating regime for the power plant is to operate in CCGT mode. The DCO application and Environmental Statement assessed up to 1500 hours of OCGT operation per annum but due to the intended operating philosophy for the plant, the actual number of operating hours would be almost certainly considerably less.

5.3.5. The Applicant has confirmed its intention is maximise operation of the power plant in CCGT mode to improve plant efficiency. There is however a need to run the plant in OCGT mode for peaking purposes. For this, the plant would start-up and be at full load in the order of minutes. The intention would be to run the plant in OCGT mode for up to 2 hours and then the plant would run in CCGT mode or shut down.

5.3.6. From cold, it can be assumed that the CO_2 capture plant would take 2 hours before it is ready for operation. Consequently, for each start-up there is a period of approximately 2 hours in which CO_2 is not captured. To offset the CO_2 released during this period, there are certain changes that could be made to increase the CO_2 capture rate during operation and therefore ensuring an overall CO_2 capture rate of 90%. These changes may include:

- Absorber column temperature may need to be reduced to less than 35°C;
- Height of the absorber column increased;
- Amine concentration/circulation rate increased.

5.3.7. At the time of implementing a CO2 capture plant for the Proposed Scheme, the anticipated operating pattern shall be reassessed and it shall be confirmed the design of the CO2 capture plant will achieve an overall CO2 capture rate of at least 90%. It is expected that any necessary control measures will be included in the DCO or Environmental Permit for the plant to ensure that it complies with the regulatory regime at the time.

5.4 CO_2 Capture Technology Requirements

5.4.1. CO_2 capture technologies require large amounts of power to run, for example, to operate pumps and blowers and for the compression of the CO_2 product for onward transport in an efficient manner. A relatively small power demand is also required for the purposes of control and instrumentation.

5.4.2. Additionally, post-combustion CO_2 capture technology using amine solvent requires steam to regenerate the liquid amine solvent. In the case of CCGT operation, (presented as Option A in this CCR Statement, where steam is taken from the power plant), this steam would otherwise be used in the steam cycle to generate power and hence the CO_2 capture equipment imposes a power penalty through its steam requirement.

5.4.3. This combination causes a significant reduction in the net electrical output and efficiency of the power plant. This has further impacts on the economics which are then required to be restored, for example through the implementation of CO_2 reduction revenues.

5.4.4. Additionally, substances such as particulate matter (PM), sulphur dioxide (SO_2), nitrogen dioxide (NO_2) and oxygen (O_2) have a detrimental effect on the CO_2 capture technology. The effects range from reduction in efficiency to the generation of solids (such as heat stable salts (HSS)) within the CO_2 capture plant. The HSS can cause problems (such as foaming) and therefore require filtration and addition of makeup liquid amine solvent.

5.4.5. Flue gases from gas fired power plants, such as the Proposed Scheme, typically contain small amounts of NO_2 and approximately 14% excess O_2. Whilst NO_2 forms HSS when it reacts with the liquid amine solvent, when levels of NO_2 are below 10 ppm (approximately 21 mg/Nm3) these can be effectively countered. As NOx typically contains less than 10% NO_2, the level of NO_2 in the flue gas from Unit X and Unit Y should not cause difficulty for the standard post-combustion CO_2 capture technology (using amine solvents). In addition, whilst O_2 also reduces the efficiency of the post-combustion CO_2 capture technology (using amine solvents), all calculations relating to the CO_2 capture in this CCR Statement are based on typical gas fired power plant flue gases. As such, the quantity of O_2 has already been taken into account.

5.5 Likely Future Developments in CO_2 Capture Technology

5.5.1. CO_2 capture technology providers are considering a number of methods for improving their technologies / processes. There are many methods currently suggested ranging from a simple method of incorporating heat recovery to more complicated methods such as flue gas recirculation[4].

5.5.2. In particular, one method is the generation of the steam required through supplementary firing. This supplementary firing not only reduces the impact of the CO_2 capture process on the power plant, but also reduces the quantity of oxygen in the flue gas. However, it also increases the quantity of CO_2 to be captured and therefore increases the scale of the CO_2 capture equipment.

5.5.3. As with alternative technologies, these possible improvements have not been included in this document. However, new developments in CO_2 capture technology will be reviewed on an ongoing basis as part of the CCR status reports to be submitted within three months of full commissioning of the Unit X generating unit and then every two years (secured by requirements to the draft DCO (document ref. 3.1)), with a view to incorporating any developments into an updated design of the CO_2 capture plant.

5.5.4. Possible vendors for post-combustion CO_2 capture (based on amine solvents) include: Siemens (PostCap Process); Mitsubishi Heavy Industries (MHI); Fluor Daniel (licence holder of the Economine FG process); Cansolv (acquired by Shell Global Solutions); Aker Clean Carbon; HTC; C&I Lummus (previously ABB Lummus); Carbon Clean Solutions Ltd; and, Powerspan. Discussions (2008) with both Fluor Daniel and Cansolv indicate that it is technically feasible to build a CO_2 capture plant for a 1,000 MW gas fired power plant, with a development time in the region of 12 months (once flue gas conditions are known) and a construction time of in the region of 36 months. In the case of this development, increasing this to up to an 1,800 MW or up to a 3,600 MW gas fired power plant would require additional CO_2 capture lines. The alternative of scaling up the equipment for this technology is not an option.

[4] Flue gas recirculation involves the recirculation of some of the flue gas exhaust from the gas turbine to the air intakes of the gas turbine. This process has the effect of concentrating the CO_2 in the flue gas when it reaches the HRSG stack thereby making the CO_2 capture process more efficient and providing economies of scale.

6 TECHNICAL ASSESSMENT – SPACE

6.1 Space Requirement for Unit X and Unit Y with Post-Combustion CO_2 Capture

6.1.1. Table 1 of the CCR Guidance (Approximate Minimum Land Footprint for some types of CO_2 Capture Plant) is intended to provide applicants, local authorities and statutory advisors with an approximate indication of the scale of carbon capture equipment which may be necessary. That is, it is intended to provide an indication of the space requirement. Table 1 of the CCR Guidance is based on net plant capacities of around 500 MW.

6.1.2. However, examination and tracing of the origin of Table 1 (column 1) of the CCR Guidance[5] has allowed for identification of the following facts for the space requirement for a "CCGT with post-combustion capture":

- Table 1 (column 1) of the CCR Guidance originates from the IEA GHG Study 2005/1 (Ref. 6.1), and should relate to a 785 MW gas fired power plant and not a 500 MW gas fired power plant; and,
- Table 1 (column 1) of the CCR Guidance provides an incorrect space requirement which should be reduced.

6.1.3. Accordingly, Table 3 provides the IEA GHG Study 2005/1 space requirement, the original space requirement and reduced (corrected) space requirement for Table 1 (column 1) of the CCR Guidance.

Table 3 – Quoted Space Requirements for a CCGT with Post-Combustion Capture

	IEA Study 2005/1	CCR Guidance	
	CCGT Power Plant with Post-Combustion CO_2 Capture	Original Space Requirement	Reduced (Corrected) Space Requirement
Net MW Generating Capacity	785	500	500
Site Dimensions – CO_2 Capture Equipment (m)	250 × 450	250 × 450	-
Site Footprint – CO_2 Capture Equipment (ha)	3.75	3.75	2.40

6.1.4. Without further design development, based on the above information, the space requirements for the CO_2 capture equipment for a CCGT power plant with post-combustion CO_2 capture technology can be conservatively calculated on a linear basis in line with plot area requirement of 2.4 ha/500 MW. The space requirement for Unit X and Unit Y using this design basis are presented in Table 4.

[5] 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 Energy Act 1998, Imperial College, 2010

Table 4 – Space Requirements Unit X and Unit Y without Post Combustion CO_2 Capture Technology

Net Generating Capacity (MW)	**CCR Guidance Reduced (Corrected) Space Requirement**		
Net Generating Capacity (MW)	500	1,800 (Unit X)	3,600 (Unit X and Unit Y)
Space Requirement for CO_2 Capture Equipment (ha)	2.40	8.64	17.28

6.1.5. A CCR land allocation of 19.4 ha has been provided for Unit X and Unit Y – this is termed the carbon capture readiness reserve space in the DCO Application. This area includes 17.4 ha of land for CCS plant equipment (exceeding guidance requirement in Table 4 above), 1.7 ha for landscaping (woodland strips) and 0.3 ha to allow diversion to public rights of way. The total extent of the land provided for carbon capture is shown in Figure 1. The draft DCO includes a requirement to safeguard the land required for CCR.

6.2 Outline Plot Level Plan

6.2.1. In addition to meeting the space requirements for an 1,800 MW or 3,600 MW gas fired power plant with CO_2 capture technology, it is also considered equally important to demonstrate that the available space can physically accommodate the CO_2 capture technology. Therefore, indicative equipment layouts for the CO_2 capture equipment have been developed for the 1,800 MW and 3,600 MW cases. These indicative plot plans for Unit X and Unit Y and the proposed CCR land can be seen in Figures 3 and 4 of Appendix 1 for the 1,800 MW and 3,600 MW cases, respectively. The equipment indicated in the plot plans have been sized based on a CO_2 capture plant for the Siemens SGT5-8000H gas turbine. Siemens have confirmed that the equipment sizes will be the same for flue gases coming from a Siemens SGT5-9000HL gas turbine.

6.2.2. The outline plot level plans for the proposed CCR Land indicates:

- The proposed location of the CO_2 capture plant / equipment;
- The proposed location of the CO_2 compression plant / equipment;
- The proposed location of the chemical storage facilities; and
- The proposed location for the coolers and utility systems.

6.2.3. Accordingly, at the point of construction of CO_2 capture technology, the outline plot plans show that the proposed CCR land would principally include the following (with reference to the numbers on Figures 3 and 4 included in Appendix 1):

- Flue Gas Coolers (1)
- Flue Gas Blower (2);
- Absorber Column (3);
- Stripper Column (4);
- Unloading/Loading Storage (5);
- Electrical Power / Steam Condensate Area (6);
- CO_2 Compression Plant Area (7);

- Admin Building(s) (8);
- Utilities and Balance of Plant Area (9);
- Areas for Coolers, Heat Exchangers and Flash Compressor Units (10); and
- Auxiliary HRSG (11).

6.2.4. Whilst the outline plot plans are drawn to scale, it should be noted that this document is a CCR Statement and not a detailed specification. Therefore, the outline plot plans are illustrative only, showing areas for the major items of plant / equipment.

6.3 CCR Status and Full Development of CCS

6.3.1. As required by the CCR Guidance, this “Technical Assessment – Space” will be reviewed on an on-going basis as part of the CCR status report to be submitted within three months of full commissioning of the Unit X generating unit and then every two years (secured by requirements to the draft DCO), with a view to incorporating any developments into an updated design of the CO_2 capture plant.

7 TECHNICAL ASSESSMENT – RETROFITTING AND INTEGRATION

7.1 Guidance

7.1.1. The CCR Guidance notes that the aim of the technical assessment is to demonstrate that the power plant has been designed in such a way so as to enable the subsequent retrofitting and integration of CO_2 capture technology. Accordingly, the technical assessment of retrofitting and integration in this CCR Statement has been made against the information provided in Annex C of the CCR Guidance (Environment Agency Verification of CCS Readiness New Natural Gas Combined Cycle Power Station using Post-Combustion Solvent Scrubbing). This Annex is provided in Appendix 4.

It is noted that the CCR Guidance also states that the UK Government will not insist that an applicant must, when CCR turns to CCS, install the CO_2 capture technology or the associated supporting infrastructure technology stated in their CCR Statement. This is due to the recognition that CO_2 capture technologies are still developing and applicants / operators should not be bound to retrofit and integrate a CO_2 capture technology which is less effective and economical than those that may become available.

7.2 Gas Turbine Operation with Increased Exhaust Pressure

7.2.1. Pressure drops to be expected downstream of the gas turbine as a result of the HRSG and the new CCS plant include:

- The gas side pressure drop across the direct contact cooler and absorber column – typically 40 to 100 mbar; and
- The exhaust pressure drop across the HRSG and ducting – typically 30 to 35 mbar.

7.2.2. As such, the total gas side pressure drop is estimated to be at least 70 mbar. This applies equally to each absorber train, since common flue gas headers are likely to be used.

7.2.3. Whilst the actual effect of pressure drop varies with specific gas turbine models, generally speaking, an increase in exhaust pressure reduces the gas turbine output and efficiency. It is therefore beneficial to keep the exhaust pressure for the gas turbine low. As an estimate, an increase in exhaust pressure of 25 mbar would result in a loss of electrical power output of approximately 10 MW.

7.2.4. As the maximum allowable gas turbine exhaust pressure drop is typically around 50 mbar, the design for the CO_2 capture plant in this CCR Statement has included a booster fan to overcome the additional pressure drop across the direct contact cooler and absorber column and across the HRSG and ducting. Whilst the booster fan power consumption versus the reduced power generated by the gas turbines will require some optimisation, the principal function of the fans is to prevent a high back pressure on the gas turbines, which could lead to tripping of the gas fired power plant. Accordingly, the power requirement for the booster fan is approximately 11 MW and has been included in the CO_2 capture plant power requirement.

7.2.5. When the gas turbines are operating in OCGT mode, there would be less pressure due to bypassing of the GT. The flue gas will still however need to be directed through the booster fan to overcome pressure drop from the direct contact coolers and the absorber column.

7.2.6. Whilst it is not possible to provide specifications for the booster fan at this stage without performing a more detailed design of the CO_2 capture plant, adequate provision of space has been provided on the CO_2 capture plant for its installation. Therefore, based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.3 Flue Gas System

7.3.1. Figures 3 and 4 in Appendix 1 shows an indicative route from proposed Unit X and Unit Y stack areas to the CO_2 capture plant. It can be confirmed there is suitable space for the ducting with minimal obstructions. The retrofitting area for the flue gas stacks has not been shown on the Figures as the final location for power plant stacks is not known. However, it has been confirmed that sufficient space will be provided to allow modification of the stack to allow diversion to the CO_2 capture plant.

7.3.2. The provision of space for stand-alone direct contact flue gas coolers will allow for the removal of any SOx that may be present in the flue gases at the time of installing the CO_2 capture plant. Selective Catalytic Reduction (SCR) is not deemed to be required for the CO_2 capture process assumed in this CCR Statement as the LCPD / IED Limits for NOx will result in flue gas containing a quantity of NO_2 that will not impact on the CO_2 capture process.

7.3.3. Therefore, based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.4 Steam Cycle

7.4.1. As noted in section 4 (Proposed CO_2 Capture Technology), steam is required for the stripping of CO_2 from the amine solvent in the CO_2 capture process.

7.4.2. Process providers (vendors) currently quote a range of condensing temperatures (and therefore pressures) for this steam. Vendors also quote a range of specific energy requirements for regeneration of the amine solvent. Thus, the quantity of steam which will be required for the CO_2 capture process will ultimately be dependent upon the chosen process provider and the specific technology selected.

7.4.3. Initial energy and saturated steam requirement estimates were obtained from three different vendors. These are shown in Table 5.

Table 5 – Estimates of Saturated Steam Requirements for CO_2 Capture Process

	Unit	Vendor A	Vendor B	Vendor C
Specific Energy Consumption	GJ/tonne CO_2	2.9	2.95	<3.0
Steam Pressure	bara	4	3.6	4.5

7.4.4. The highest steam temperature quoted by vendors is in the region of 148ºC. This equates to a pressure of 4.5 bara as shown in Table 5 (Vendor C). Therefore, in order to cover steam pressure drop and allow for a margin, a steam pressure of 5 bara was used for the base case steam pressure. As such, the steam delivered to the CO_2 capture plant for the base case carbon capture process was modelled at:

- Specific Energy Consumption – 3 GJ/tonne CO_2;
- Steam Pressure – 5 bara; and,
- Steam Flow – 213 kg/s (for Unit X) / 426 kg/s (for Unit X and Unit Y).

7.4.5. When the Proposed Scheme is operating in CCGT mode, the steam will be extracted from the steam cycle of the gas fired power plant. For the purpose of the CCR Statement, it has been assumed that a largely standard power plant design for Unit X and Unit Y is installed and then when required, CO_2 capture technology equipment is retrofitted into the design. This has been identified as Scenario A1 in Section 4 of this CCR Statement.

7.4.6. The steam could be extracted from the Cold Reheat (CRH) line or the Intermediate Pressure (IP) turbine exhaust. The suitability of each will depend on the final steam turbine configuration and design capability of the HRSG and steam turbine. At present it is considered likely that the steam turbine would have one of the following configurations:

- Option 1: Separate High Pressure (HP) turbine, IP turbine and a two-flow low pressure (LP) turbine with a lateral exhaust; or,
- Option 2: Combined HP / IP turbine plus separate two-flow LP turbine with lateral exhaust.

7.4.7. Other possible configurations are:

- Option 3: HP turbine, plus combined IP / LP turbine with an axial exhaust; or,
- Option 4: Single casing HP / IP / LP turbines with an axial exhaust.

7.4.8. In terms of extracting steam from the CRH line, steam can be extracted from the CRH line with any of the above options.

7.4.9. In terms of extracting steam from the IP turbine exhaust, for Options 1 and 2, with separate LP turbine cylinders, the steam exits the IP turbine and is delivered to the LP turbine via the LP crossover pipe. Therefore, in Options 1 and 2, a modified LP crossover pipe could be retrofitted, with an off-take port incorporated for the CO_2 capture process. The design of this should be such that excessive forces, moments and stresses are not imposed on the LP crossover pipe and the turbine. This would not be possible for Options 3 and 4.

7.4.10. In this CCR Statement, it was assumed that steam was extracted from the CRH line, so all of the above options can be included. To allow retrofitting and integration, this would require space for an off-take port on each CRH line as well increasing the de-superheating capability. The layout and temperature profile of the reheater should also be checked to allow for the higher levels of de-superheating and to prevent overheating of the tubes. If this is employed, steam could be extracted and provided at any pressure up to the pressure of the CRH line. This would not require that an off-take port is provided from the steam turbine and is therefore independent of the choice of steam turbine manufacturer. As part of the Proposed Scheme, modification to the existing steam turbine will be made to be configured with the new HRSGs. Future retrofitting of the cold reheat line for supply of steam to the CCR will be considered as part of the design.

7.4.11. However, the final decision on the option to implement and the location for the associated off-take port would come at the time of detailed design and installation of the CO_2 capture plant. This would depend upon, but not restricted to the following:

- Fuel price;
- Carbon price;
- Electricity market conditions;
- Capital cost of retrofitting; and
- Age and condition of power plant (for example, it might be an opportune time to refurbish and / or upgrade the steam turbine).

7.4.12. In addition, extra steam might be required during some periods (e.g. if the CO_2 capture process calls for the storage of rich amine during periods of high electricity prices and stripping during periods of low electricity prices). These options have not been considered in the base case design. However, it is recommended that these options are considered further during the detailed design of the steam system.

7.4.13. Illustrative overall performance results utilising a base case power plant with a net power output of 1,800 MW and a net Lower Heating Value (LHV) efficiency of 60.0% with CO_2 capture are:

- Overall net power output (with steam supplied from CRH line) of 1,529 MW with an LHV efficiency of 51.0%.

7.4.14. Illustrative overall performance results utilising a base case power plant with a net power output of 3,600 MW and a net Lower Heating Value (LHV) efficiency of 60.0% with CO_2 capture are:

- Overall net power output (with steam supplied from CRH line) of 3,060 MW with an LHV efficiency of 51.0%.

7.4.15. Steam will also be required during the reclaiming process, which will operate intermittently, concurrently with the CO_2 capture process. The steam required for reclaiming is typically at a higher pressure than that required for CO_2 capture, and would require a flowrate of the order of 14.0 kg/s for the 1,800 MW case and 28.0 kg/s for the 3,600 MW case. The steam system should therefore be designed to allow for the flow of this additional higher pressure steam, which like the 5 bara supply, will most likely be provided via its own dedicated let down station on the CO_2 capture plant.

7.4.16. When the Proposed Scheme is operating in OCGT mode, steam from the power plant steam cycle will not be available and so steam will be required from elsewhere. For the purpose of this CCR Statement, it has been assumed steam will be provided from auxiliary HRSGs at the CCS site.

- Thermoflow modelling software has been used to assess the feasibility of utilising the hot OCGT flue gas and it has been confirmed that there is more than sufficient heat energy within the flue gas to produce process steam at the required quantity and parameters.

7.4.17. For the Unit X case, one auxiliary HRSG unit is required. For the Unit X and Unit Y case, two auxiliary HRSG are required. The Thermoflow software provides estimates for equipment sizes. To be conservative, a scaling factor has been assumed, with the increased scaled HRSG unit footprint used for the Figure 3 and Figure 4 layouts included within Appendix 1.

7.4.18. Based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.5 Cooling System

7.5.1. The CO_2 capture plant requires cooling for:

- Cooling of the flue gases to the required absorber inlet temperature (flue gas cooling);
- Cooling of the lean amine before entry to the absorber column (process cooling);
- Inter-cooling of the CO_2 compressors;
- Cooling of CO_2 capture plant ancillary equipment (plant cooling); and,
- Cooling of the condensate from the CO_2 stripping process.

7.5.2. Because of the high auxiliary cooling load of the CO_2 capture plant, water cooling is the preferred cooling option. Water cooling generally provides a lower temperature heat sink, and much smaller and less expensive heat exchangers. It has been confirmed that the Existing Drax Power Station Complex cooling towers are able to provide the cooling requirements of the CO_2 capture plant.

7.5.3. It is proposed a new cooling water supply line will be installed off the main cooling water header line from the cooler towers and piped to the CO_2 capture plant. The final design layout of the Unit X and Unit Y plants is yet to be confirmed but it is estimated a cooling load of 1300MW is required for the capture plant. It is noted that there is sufficient space to pipe the cooling water supply and return lines in between Unit X and Unit Y or to the north of Unit Y. Depending on what is being cooled and the load required, the cooling water supply will be passed through heat exchangers to cool the load directly or to extract heat from a closed loop cooling system.

7.5.4. The Applicant and Siemens have confirmed the existing cooling towers are capable of accommodating the additional heat load from the CCR plant. However, additional make-up water may be required to maintain sufficient water level in the cooling towers. In addition, as there will be a small increase to the temperature of the cooling water to the existing ST condensers, there will be an efficiency penalty to these units. To overcome this, Drax may choose to offset the efficiency penalty by installing additional cooling infrastructure near to the cooling towers or at the CCR site. As this is only additional cooling load to supplement the existing cooling towers, only a small footprint would be needed for equipment and the requirement of whether to include or not would be assessed at the detailed design stage and be a decision based on a balance between finance and performance.

7.5.5. Therefore, based on the above, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.6 Compressed Air System

7.6.1. Process compressed air will not be required but a small amount of service air and instrument air will be required for maintenance requirements and supply to the CO_2 capture plants instruments.

7.6.2. As only a small amount of compressed air is required, it is envisaged an air compressor system (air compressors, air dryers and air receivers) will be installed on the CO_2 capture plant in the utilities area.

7.6.3. In terms of sizing in the plot plan layouts (Figure 3 and Figure 4 in Appendix A), we have assumed 2 compressed air streams for the 1,800 MW plant case and 4 compressed air streams for the 3,600 MW plant case. Each stream consists of an air compressor (with a free air delivery of 1,500m3/hr at 8 bar), an air dryer and an air receiver (5,000 litre). Intermittent uses from other known projects has been the basis for sizing. Each stream has an approximate 5m x 15m footprint. Space provision for the compressed air streams have been included in the Utilities and Balance of Plant Area (Item 9 on Figure 3 and Figure 4 in Appendix A).

7.7 Demineralisation / Desalination Plant

7.7.1. Due to the absorber column design operating temperature selected for this CCR Statement, the CO_2 capture plant is a net producer of water and no evaporative losses will be realised from the flue gas.

7.7.2. However, additional demineralised water will be required to replace the water removed during the amine reclaiming process. At present this is estimated to be approximately 1.00 kg/s for the 1,800 MW case and 2.00 kg/s for the 3,600 MW case. It is currently anticipated that the demineralised water will be provided from the Existing Drax Power Station Complex water treatment plant.

7.7.3. The requirements for the demineralised water plant / equipment to accommodate the CO_2 capture plant would be finalised during detailed design. However, as the Existing Drax Power Station Complex water treatment plant is existing, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.8 Waste Water Treatment Plant

7.8.1. The process waste water discharge for the CO_2 capture plant has been estimated to be 30.85 kg/s for the 1,800 MW case and 61.7 kg/s for the 3,600 MW case.

7.8.2. It is proposed the process waste water discharge from the CO_2 capture plant can be sent to the existing flue gas desulphurisation waste water treatment plant. It has been confirmed that there is sufficient capacity in the waste water treatment plant to accept the maximum discharge flow from the CO_2 capture plant.

7.8.3. The final design of the CO_2 capture plant will have provisions to include for surface water drainage. Any contaminated surface water drainage will pass through an oil interceptor before discharge into the main plant drainage system. which would drain to oil interceptors.

7.8.4. As the Existing Drax Power Station Complex flue gas desulphurisation waste water treatment has the capacity to accept discharge from the CO_2 capture plant , the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.8.5. The generation of effluents from the carbon capture process are discussed in section 10 (Requirement for a Hazardous Substances Consent (HSC)).

7.9 Electrical

7.9.1. The CO_2 capture plant has a total estimated auxiliary power load of 84 MW for the 1,800 MW case and 169 MW for the 3,600 MW case.

7.9.2. At this stage it is suggested that this is met by a reduction of power sent from the repowered units to the NG, and the CO_2 capture plant auxiliary power load is met using auxiliary transformers deriving power from the repowered units.

7.9.3. Whilst the actual electrical requirements at this stage are not final, it is expected that the space for additional electrical items associated with specific plant items (such as pumps, fans, etc.) would be provided within the respective plant item areas illustrated in Figures 3 and 4. Indeed, these items of plant are small in size and could be readily accommodated on site. Accordingly, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.10 Plant Pipe Racks

7.10.1. The layout and sizing of plant pipe racks will allow for pipe work and duct work between Unit X and Unit Y and the CO_2 capture plant. Accordingly, the relevant plant and equipment poses no problem in relation to retrofit and integration (subject to detailed design being carried out).

7.11 Control and Instrumentation

7.11.1. The control and instrumentation system for the CO_2 capture plant is anticipated to be incorporated into the distributed control system of the Existing Drax Power Station Complex. However, provision has been made for a local control room located within the Admin Building. The provision of space for control and monitoring instrumentation would include for the routing of the cabling to and the installation of all control and monitoring instrumentation within the control room.

7.11.2. The required space for the additional control and monitoring instrumentation to accommodate control of the CO_2 capture plant would be finalised during detailed design.

7.12 Plant Infrastructure

7.12.1. The Proposed Scheme is accessible from the existing road network and is not considered to have any access constraints which could impede any future construction activities. Furthermore, the existing office and stores buildings at the Existing Drax Power Station Complex are sized sufficiently or can be readily expanded for the additional requirements of the CO_2 capture plant.

7.13 CCR Status and Full Development of CCS

7.13.1. As required by the CCR Guidance, this "Technical Assessment – Retrofitting and Integration" will be reviewed on an ongoing basis as part of the CCR status report to be submitted within three months of full commissioning of Unit X, and then every two years (secured by requirements to the draft DCO, with a view to incorporating any developments into an updated design for the CO_2 capture plant for the Proposed Scheme.

8 TECHNICAL ASSESSMENT – CO_2 STORAGE AREAS

8.1 Potential CO_2 Storage Areas

8.1.1. In order to identify potential CO_2 storage areas, it is necessary to understand the potential CO_2 storage requirement for Unit X and Unit Y operating with CO_2 capture technology. In line with the calculations detailed in Table 2 of this Statement, the CO_2 storage requirement for Unit X and Unit Y operating with CO_2 capture technology is approximately 190.07 Mt of CO_2 for a 3,600 MW plant over 25 years of operating with a CCS Plant.

8.1.2. Based on the Energy Technologies Institute (ETI) Strategic UK CCS Storage Appraisal Project (Ref. 8.1), the Endurance (5/42) and Bunter Closure 36 (Block 44/26) aquifers in the South North Sea Basin are potential CO_2 storage areas which meet the CO_2 storage requirement for Unit X and Unit Y operating with CO_2 capture technology. The analysis of the Endurance (5/42) and Bunter Closure 36 storage sites undertaken in the ETI Strategic UK CCS Storage Appraisal Project demonstrates that they are both viable / realistic CO_2 storage areas as per the requirement of the CCR Guidance. The location of the two CO_2 storage areas is illustrated in Figure 6 in Appendix 1.

8.2 CO_2 Storage Area Capacity and CO_2 Storage Requirement

8.2.1. The Endurance aquifer has a capacity of 520 Mt CO_2 and the Bunter Closure 36 aquifer has a capacity of 252 Mt CO_2.

8.2.2. Accordingly, Table 6 illustrates the percentage CO_2 storage requirements on these two stores.

Table 6 – Percentage CO_2 Storage Requirements

	CO_2 Storage Requirement (%) Based on 180.6 Mt CO_2
Endurance Aquifer 520 Mt CO_2	36.6
Bunter Closure 36 Aquifer 252 Mt CO_2	75.4

8.2.3. In the future it is likely there may be competing interest for these identified CO_2 storage areas as other CCS projects become operational. However, there are a large number of additional CO_2 storage areas which exist in the same region that are capable of meeting the CO_2 storage requirements.

8.2.4. Table 7 presents a summary of the total CO_2 storage capacity of the additional CO_2 storage areas which exist in the same region that have been characterised in the ETI Strategic UK CCS Storage Appraisal Project (Ref. 8.2).

Table 7 – Total CO_2 Storage Capacity

	Total CO_2 Storage Requirement / Capacity – 1,800 MW (Mt)	**Total CO_2 Storage Requirement / Capacity – 3,600 MW (Mt)**
CO_2 Storage Requirement	95.04	190.07
Total Additional CO_2 Storage Capacity	3,310	3,310
Percentage CO_2 Storage Requirement against CO_2 Storage Capacity	2.87	5.74

8.2.5. Whilst the decision as to which specific CO_2 storage area to use (for any project) will not be made until implementation of CO_2 transportation and storage, Table 7 shows that the additional potential CO_2 storage areas in the same region have a CO_2 storage capacity of approximately 3,310 Mt CO. Unit X and Unit Y operating with CO_2 capture technology would require only a small percentage of this CO_2 storage capacity over their 25 year lifetime for a 3,600 MW plant.

8.2.6. Another possibility is that there will be an available “CO_2 Network” in the region such that CO_2 from Unit X and Unit Y operating with CO_2 capture technology, and other power plants and industrial emitters in the Humber region, would be delivered to a “central hub”. From this “central hub”, the captured CO_2 would likely be delivered to a number of CO_2 storage areas.

8.3 CCR Status and Full Development of CCS

8.3.1. As required by the CCR Guidance, this “Technical Assessment – CO_2 Storage Areas” will be reviewed on an ongoing basis as part of the CCR status report to be submitted within three months of full commissioning of Units X and then every two years (secured by requirements to the draft DCO, with a view to incorporating any developments into an updated design for the C02 capture plant for the Proposed Scheme.

9 TECHNICAL ASSESSMENT – CO_2 TRANSPORT

9.1 CO_2 Transport Onshore

9.1.1. It is proposed that CO_2 transport onshore, from the proposed CCR land to the coastal transition point, is via an onshore CO_2 pipeline.

9.1.2. The proposed onshore CO_2 pipeline route corridors is shown in Figure 5 of Appendix 1, which illustrates a 1 km wide corridor for the first 10 km of the CO_2 pipeline route and a 10 km wide route corridor thereafter.

9.1.3. As part of the proposed White Rose CCS Project, National Grid Carbon developed a proposed CO_2 pipeline route from adjacent to the Existing Drax Power Station Complex (where the White Rose plant was to have been located) to a coastal landfall at Barmston on the North Yorkshire coast (Ref. 9.1). For the purposes of this study, it has been assumed that this proposed pipeline routing would be utilised.

9.1.4. Accordingly, the onshore CO_2 pipeline route corridors would run from the proposed CCR land north-easterly to Barmston.

9.1.5. The approximate length of the onshore CO_2 pipeline route corridor would be 60 km.

9.2 CO_2 Transport Offshore

9.2.1. It is proposed that CO_2 transport offshore, from the coastal transition point to the CO_2 storage area, is via an offshore CO_2 pipeline. The proposed offshore CO_2 pipeline route corridors are shown on Figure 6 of Appendix 1.

9.3 CO_2 Transport Barriers

CO_2 Transport Onshore

9.3.1. In terms of onshore barriers, the onshore CO_2 pipeline route corridor has followed the route of the proposed CO_2 pipeline for the White Rose CCS Project. In doing so, the onshore CO_2 pipeline route corridor has been designed in line with the following guiding principles:

- Routed away from habitation (and any potential future developments) as much as possible to reduce the impacts of construction and operation;
- Routed close to existing hydrocarbon pipelines to minimise proliferation of pipelines; and,
- Routed close to existing hydrocarbon pipelines to minimise the number of different landowners / tenants affected.

9.3.2. At the time of developing the route as part of the White Rose CCS Project, a considerable amount of work was undertaken by NG to ensure the proposed route would not be impacted by habitation (and future developments) and any existing (or planned future hydrocarbon) pipelines. Accordingly, it is considered that there are no known barriers or unavoidable safety obstacles which exist within the identified onshore CO_2 pipeline route corridor proposed for this project.

9.3.3. It may be that the onshore CO_2 pipeline would likely to run through or near to areas with environmental constraints. Typically, these include: Special Protection Areas (SPA);

Special Areas of Conservation (SAC); Ramsar sites (especially around coastal areas); Sites of Special Scientific Interest (SSSI); and Scheduled Monuments.

9.3.4. If, after further CO_2 pipeline routing, it is not possible to navigate / avoid these areas, trenchless construction techniques (i.e. auger boring / Horizontal Directional Drilling (HDD)) may be used to minimise any environmental impacts and meet any relevant regulations. Furthermore, the impact on protected habitats and species may be minimised by planning the construction of the CO_2 pipeline around breeding seasons and migrating patterns.

9.4 CO_2 Transport Considerations

Pipeline Route Selection Considerations

9.4.1. Ultimately, it is unlikely that the shortest CO_2 pipeline route from the proposed CCR land to the identified CO_2 storage area will be the most suitable, and indeed the design of any CO_2 pipeline (or CO_2 pipeline network) will take a number of factors into consideration. These will include:

- Technical factors, comprising:
  - Pipeline fluid and proposed operating conditions;
  - Likely access;
  - Likely requirements for construction, commissioning, operation, maintenance and inspection;
  - Consideration of safety (both public and personnel); and
  - Consideration of security requirements.
- Planning factors;
- Land factors, comprising:
  - Land use (historical, current and future);
  - Any agricultural practices;
  - Any third party activities; and
  - The location of the existing facilities and services (including transport and utilities).
- Environmental factors, comprising:
  - Consideration of the location of Statutory Designated Sites; and
  - Geological conditions (including topographical, geotechnical and hydrographical conditions).

9.4.2. Therefore, in order to further develop the CO_2 pipeline route from the proposed CCR land to the identified CO_2 storage area, it is likely that three phases of routing would be adopted. The phases of routing would be:

- Phase 1: CO_2 pipeline route corridor selection.
- Phase 2: CO_2 pipeline route corridor investigation and consultation.
- Phase 3: Design and approval of the final CO_2 pipeline route.

Safety Considerations

9.4.3. As noted in the CCR Guidance, it may be that dense phase CO_2 would be present on-site and within the CO_2 pipeline once the captured CO_2 is compressed in preparation for transport. Whilst dense phase CO_2 is not currently classified as hazardous, it is now recognised that an accidental release of large quantities of CO_2 could result in a major accident. As such, there is currently extensive ongoing research into the hazard potential of dense phase CO_2. The results of this ongoing research will inform future decisions on CO_2 and whether a classification review (i.e. dense phase CO_2 is classified as hazardous) is necessary.

9.4.4. As a result, in terms of CO_2 pipeline routes / transport, the mechanisms, hazards, consequences and probabilities of CO_2 pipeline failure need to be understood so that safe design, commissioning and operation can be ensured. Accordingly, a precautionary approach has been taken in respect of dense phase CO_2 to ensure no foreseeable barriers exist along the proposed CO_2 pipeline route.

9.4.5. In line with the precautionary approach, the Health and Safety Executive (HSE) require that dense phase CO_2 is treated as a "dangerous fluid" under the Pipeline Safety Regulations 1996 (Ref 9.2).

9.4.6. In addition, a dense phase CO_2 pipeline would be treated as a Major Accident Hazard Pipeline under the Pipeline Safety Regulations 1996. As such, the following documents / considerations would need to be produced / included for the ultimate design, commissioning and operation of a dense phase CO_2 pipeline:

- A Major Accident Prevention Plan;
- A Pipeline Safety Evaluation and Technical Safety Risk Assessment, including failure mechanisms, probability and consequence of failure. Mitigation measures will also be detailed;
- An Asphyxiation Risk Assessment;
- An Operations, Maintenance and Emergency Response Policy, including procedures and work instructions for:
  - The safe control of operations; and
  - The safe working in the vicinity of a high pressure pipeline.
- Emergency shutdown valves to be fitted to the CO_2 pipeline; and
- The relevant Local Authority to be notified and this Local Authority to have prepared an Emergency Plan.

9.4.7. However, it is not yet necessary to address these items at this stage due to the uncertainty surrounding the final CO_2 pipeline route and the classification of dense phase CO_2. In this regard, it is recommended that the Applicant hold informal discussions with the Local Planning Authority (LPA) about the potential issues surrounding dense phase CO_2, including the implications behind transport via a dense phase CO_2 pipeline. These informal discussions are expected to continue until further information concerning the classification of dense phase CO_2 is available. This will ensure that there is early identification of any potential implications on the LPA's long term plan for the area. However, at this stage it is felt that no formal discussions or preparations are necessary.

9.5 CCR Status and Full Development of CCS

9.5.1. As required by the CCR Guidance, this "Technical Assessment – CO_2 Transport" will be reviewed on an ongoing basis as part of the CCR status report to be submitted within three months of full commissioning of Units X and then every two years (secured by requirements to the draft DCO), with a view to incorporating any developments into an updated design for the CO_2 capture plant for the Proposed Scheme.

10 ECONOMICS ASSESSMENT

10.1 Introduction

10.1.1. It is proposed that CO_2 transport onshore, from the proposed CCR land to the coastal transition point, is via an onshore CO_2 pipeline.

10.1.2. The proposed onshore CO_2 pipeline route corridors is shown in Figure 5, which illustrates a 1 km wide corridor for the first 10 km of the CO_2 pipeline route and a 10 km wide route corridor thereafter.

10.1.3. This section presents the results of the economic assessment which investigates the feasibility of incorporating CO_2 capture technology into the Proposed Scheme. The economic assessment tests a number of key industry and market sensitivities.

10.1.4. The assumptions used in the economic assessment and analysis within this report are consistent with those used in previous CCR Studies undertaken by WSP UK Limited and align with the requirements in the CCR Guidance.

10.2 Comments on the CCR Guidance

10.2.1. As part of an application for consent, the CCR Guidance states (at paragraph 7) that, amongst other things, applicants will be required to demonstrate:

"the likelihood that it will be economically feasible within the power station's lifetime, to link it to the full CCS chain, covering retrofitting of capture equipment, transport and storage".

10.2.2. Additionally, the CCR Guidance states (at paragraph 63) that:

"Directive 2009/31/EC requires applicants to carry out an assessment of the economic feasibility of retrofitting and transport. Recital 47 states that "*The economic feasibility of the transport and retrofitting should be assessed taking into account the anticipated costs of avoided* CO_2 *for the particular local conditions in the case of retrofitting and the anticipated costs of* CO_2 *allowances in the Community. The projections should be based on the latest evidence; a review of technical options and uncertainty analysis should also be undertaken*".

10.2.3. Accordingly, in terms of undertaking an economic assessment the CCR Guidance notes (at paragraph 68) that a wide range of parameters are likely to be included, including:

- Assumed £ / € exchange rate;
- Future fuel prices (both absolute and relative to other fuels);
- Electricity price levels;
- Carbon price;
- Power output with / without CO_2 capture, transport and storage;
- Lifetime load factor;
- CO_2 emitted with / without CO_2 capture, transport and storage;
- Estimations of costs of retrofitting CO_2 capture equipment (construction and operation);
- Estimations of costs of transport (construction and operation);
- Estimations of costs of storage (permitting and operation); and
- Reasonable estimations of when these costs would be incurred.

10.2.4. It should be noted that the estimations of costs used in this economic assessment are based on those for CO_2 capture equipment, transport and storage based on technology available in 2013. The 2013 costs used are based on CCS plant design and performance parameters released by CCS technology developers to the public domain. The costs have been escalated to a 2018 basis. (Current CCS technology costs are typically proprietary and have not released into the public domain by CCS technology developers).

10.2.5. It is noted that costs are expected to reduce in time, bearing in mind the recent and likely future developments in technology.

10.3 Assessment Methodology

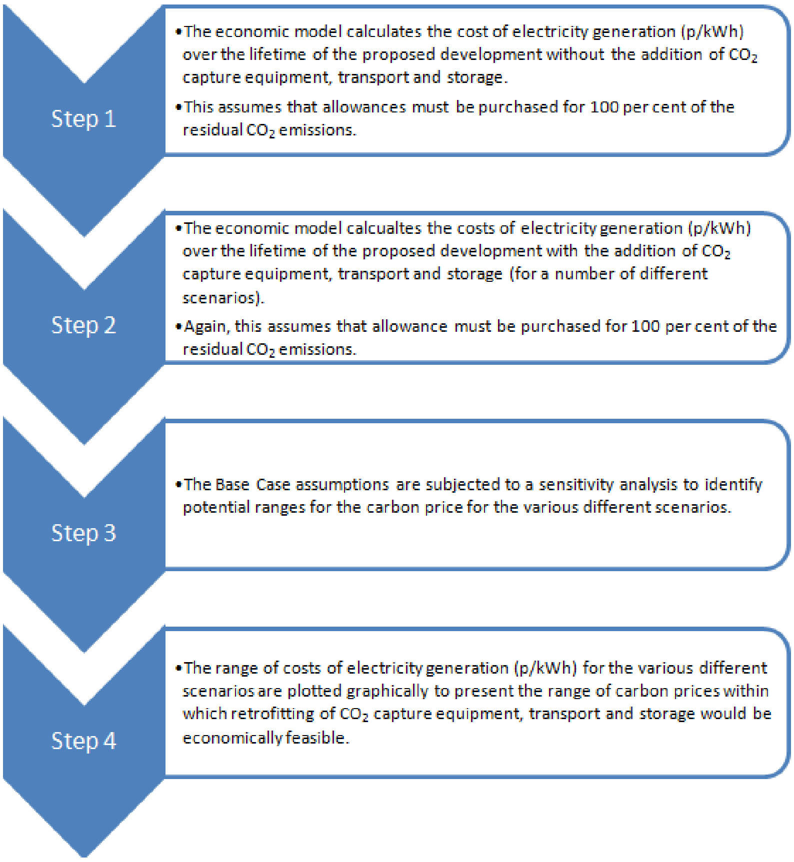
10.3.1. To investigate the economic feasibility of adding CO_2 capture equipment to the repowered units, an economic model has been developed to calculate the lifetime cost of electricity, expressed in p/kWh, over the assumed 25 year lifetime of Units X and Y.

10.3.2. As required by the CCR Guidance, the economic model encompasses the likely costs of CO_2 capture equipment, transport and storage. However, the effects of taxation have not been considered in the economic model.

10.3.3. Using the economic model, the economic feasibility of the repowered units was assessed by varying the price of EU Allowances under the EU Emissions Trading Scheme (EU ETS) / UK Carbon Floor Price (carbon price) whilst the remaining parameters remained constant. Carbon prices ranged from €0/t CO_2 to €150/t CO_2 in €25/t CO_2 increments. This allowed for the identification of the carbon price where Units X and Y with CO_2 capture equipment, transport and storage would become economically feasible.

10.3.4. The assessment methodology is shown in Figure 1.

Figure 1 – Economics Assessment Methodology



10.4 Estimations / Assumptions

10.4.1. The main estimations and assumptions made in the economic assessment are detailed in Table 8.

Table 8 – Base Case Estimations / Assumptions

Variable	Estimation / Assumption
Assumed First Year of Operation	2022
£:€ Exchange Rate[6]	1.09
Nominal Discount Rate	10%
Gas Price	65.1 p/therm [7]
Carbon Allocations	None for Power Sector– Full Purchase
CO_2 emitted by the repowered units in CCGT mode before CO_2 capture	Approximately 330 kg/MWh
CO_2 emitted by the repowered units in CCGT mode after CO_2 capture (Based on a 94.71% Capture Rate)	Approximately 17 kg/MWh

[6] Exchange rate taken on 22nd August 2017.
[7] One therm is equal to 29.3 kWh

10.5 Economic Assessment Scenarios

10.5.1. The economic model runs three possible scenarios relating to the readiness level of the CO_2 capture technology and the possible transport and storage infrastructure options. These three possible scenarios are:

- Scenario A. First of a Kind Plant, with dedicated Transport and Storage.

10.5.2. Scenario A assumes that Unit X / Unit Y will be the first to be fitted with CO_2 capture equipment, transport and storage amongst the CCR power plant fleet. This means that the construction cost will be relatively high because of the lack of experience.

10.5.3. In addition, it is assumed that all of the onshore and offshore transport and storage infrastructure will be based on new assets. This infrastructure will be sized to the repowered units and would be 'dedicated'.

- Scenario B. First of a Kind Plant, with dedicated Transport and Reused Storage.

10.5.4. Scenario B assumes that the storage infrastructure can be re-used, but both onshore and offshore transport pipelines are based on new assets that would be sized to the repowered units. Storage site re-use will allow for a reduction in storage costs.

- Scenario C. Nth of a Kind Plant, with shared Transport and Storage.

10.5.5. Scenario C assumes that Unit X / Unit Y will be fitted with CO_2 capture equipment, transport and storage after the majority of the CCR power plant fleet. This means that the construction cost will be relatively lower due to learning curve effects.

10.5.6. The above assumption entails that a CO_2 network with several other emitters will be possible. To recognise this possibility, the economic model has been run for a case where the transport and storage system (and associated costs) is shared[8]. Associated costs allocated to the repowered units have been assumed to be approximately 16% in this economic assessment.

10.6 Sensitivity Analysis

10.6.1. On each economic assessment scenario, the economic model has the capability to vary the three sensitivities listed below:

- Discount Rate: Whilst a nominal 10% discount rate is considered to be a reasonable value for a base case analysis, the retrofitting of CO_2 capture equipment, transport and storage at some time in the future is considered to present an additional risk to developers. Therefore, a higher risk- adjusted discount rate of 12.5% has been added to reflect this risk.
- Gas Price: Volatility in the gas market (assuming continued linkage with oil) in the UK in recent years has shown that there remains significant uncertainty in the longer term forward gas price. Therefore, the economic assessment has modelled what is considered to be outlying possibilities for the gas price with a ±30% range.

[8] Whilst the CCR Guidance states that outsourcing transport and storage cannot be assumed in a CCR Statement, such an option is included for comparative purposes.

- Capital Cost: The capital cost for the repowered units has been stressed with a ±10% uncertainty range. This uncertainty is applied to the proposed scheme itself and the CO_2 capture equipment, transport and storage.

10.6.2. Based on these three sensitivities, the economic model runs illustrated in this economic assessment show the cumulative effects of factors increasing the cost of electricity (high gas price, high capital cost, high discount rate), and of factors decreasing the cost of electricity (low gas price, low capital cost). Accordingly, Table 9 describes the high and low sensitivity runs for each economic assessment scenario.

Table 9 – Sensitivity Analysis Runs

	Discount Rate	Gas Price	Capital Costs
High	12.5 %	+30 %	+10 %
Low	10 %	-30 %	-10 %

10.7 Economic Assessment – 1,800 MW (Unit X)

10.7.1. The results of the 1,800 MW (Unit X only) economic assessment are shown in Figure 2 and Figure 3 in this section below. The carbon price is shown along the horizontal axis and the lifetime cost of electricity (in p/kWh) is shown along the vertical axis. Solid lines represent the base case of each scenario and dotted lines represent the upper and lower limits of the sensitivity analysis runs.

10.7.2. Figure 2 compares the results of the economic model for Unit X (black line) with Scenario A (purple line) and Scenario B (red line). Figure 2 shows that:

- In the economic model for Unit X (black line), the lifetime cost of electricity ranges between 5.58 p/kWh (at €0/t CO_2) and 10.13 p/kWh (at €150/t CO_2);
- In the economic model for Scenario A (purple line), the lifetime cost of electricity ranges between 9.14 p/kWh (at €0/t CO_2) and 9.60 p/kWh (at €150/t CO_2); and
- In the economic model for Scenario B (red line), the lifetime cost of electricity ranges between 9.01 p/kWh (at €0/t CO_2) and 9.47 p/kWh (at €150/t CO_2).

10.7.3. Therefore, under the base case, the minimum required carbon price such that the cost of electricity over the life of Unit X fitted with CO_2 capture equipment, transport and storage remains the same value as that for the repowered unit (without CO_2 capture equipment, transport and storage) is approximately €125/t CO_2. Furthermore, even with storage site re-use the break-even carbon price only decreases by a few €/t CO_2.

10.7.4. Figure 3 compares the results of the economic model for Unit X (black line) with Scenario C (green line). Figure 3 shows that:

- In the economic model for Unit X (black line), the lifetime cost of electricity ranges between 5.58 p/kWh (at €0/t CO_2) and 10.13 p/kWh (at €150/t CO_2); and
- In the economic model for Scenario C (green line), the lifetime cost of electricity ranges between 8.10 p/kWh (at €0/t CO_2) and 8.55 p/kWh (at €150/t CO_2).

10.7.5. Therefore, under the base case, the minimum required carbon price such that the cost of electricity over the life of Unit X fitted with CO_2 capture equipment, transport and storage remains the same value as that for the repowered unit (without CO_2 capture equipment, transport and storage) is approximately €90/t CO_2.

10.8 Economic Assessment – 3,600 MW (Unit X and unit Y)

10.8.1. The results of the 3,600 MW (both Units X and Y) economic assessment are shown in Figure 4 and Figure 5.

10.8.2. The carbon price is shown along the horizontal axis and the lifetime cost of electricity (in p/kWh) is shown along the vertical axis. Solid lines represent the base case of each scenario and dotted lines represent the upper and lower limits of the sensitivity analysis runs.

10.8.3. Figure 4 compares the results of the economic model for the repowered units (black line) with Scenario A (purple line) and Scenario B (red line). Figure 4 shows that:

- In the economic model for Unit X and Unit Y (black line), the lifetime cost of electricity ranges between 5.49 p/kWh (at €0/t CO_2) and 10.04 p/kWh (at €150/t CO_2);
- In the economic model for Scenario A (purple line), the lifetime cost of electricity ranges between 9.07 p/kWh (at €0/t CO_2) and 9.52 p/kWh (at €150/t CO_2); and
- In the economic model for Scenario B (red line), the lifetime cost of electricity ranges between 8.94 p/kWh (at €0/t CO_2) and 9.40 p/kWh (at €150/t CO_2).

10.8.4. Therefore, under the base case, the minimum required carbon price such that the cost of electricity over the life of Unit X and Unit Y fitted with CO_2 capture equipment, transport and storage remains the same value as that for Unit X and Unit Y (without CO_2 capture equipment, transport and storage) is approximately €125/t CO_2. Furthermore, even with storage site re-use the break-even carbon price only decreases by a few €/t CO_2.

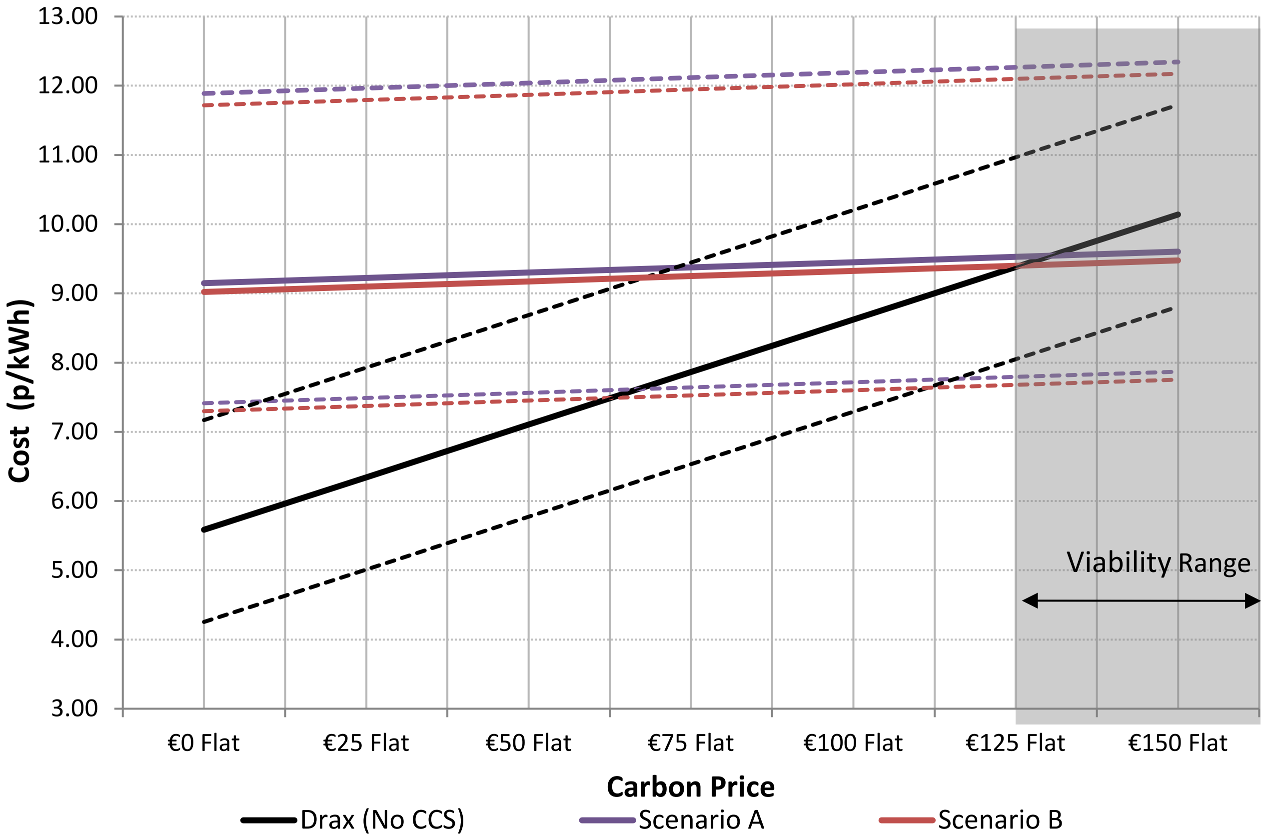
10.8.5. Figure 5 compares the results of the 3,600 MW economic model for Unit X and Unit Y (black line) with Scenario C (green line). Figure 5 shows that:

- In the economic model for Unit X and Unit Y (black line), the lifetime cost of electricity ranges between 5.49 p/kWh (at €0/t CO_2) and 10.04 p/kWh (at €150/t CO_2); and
- In the economic model for Scenario C (green line), the lifetime cost of electricity ranges between 8.03 p/kWh (at €0/t CO_2) and 8.48 p/kWh (at €150/t CO_2).

10.8.6. Therefore, under the base case, the minimum required carbon price such that the cost of electricity over the life of Unit X and Unit Y fitted with CO_2 capture equipment, transport and storage remains the same value as that for Unit X and Unit Y (without CO_2 capture equipment, transport and storage) is approximately €90/t CO_2

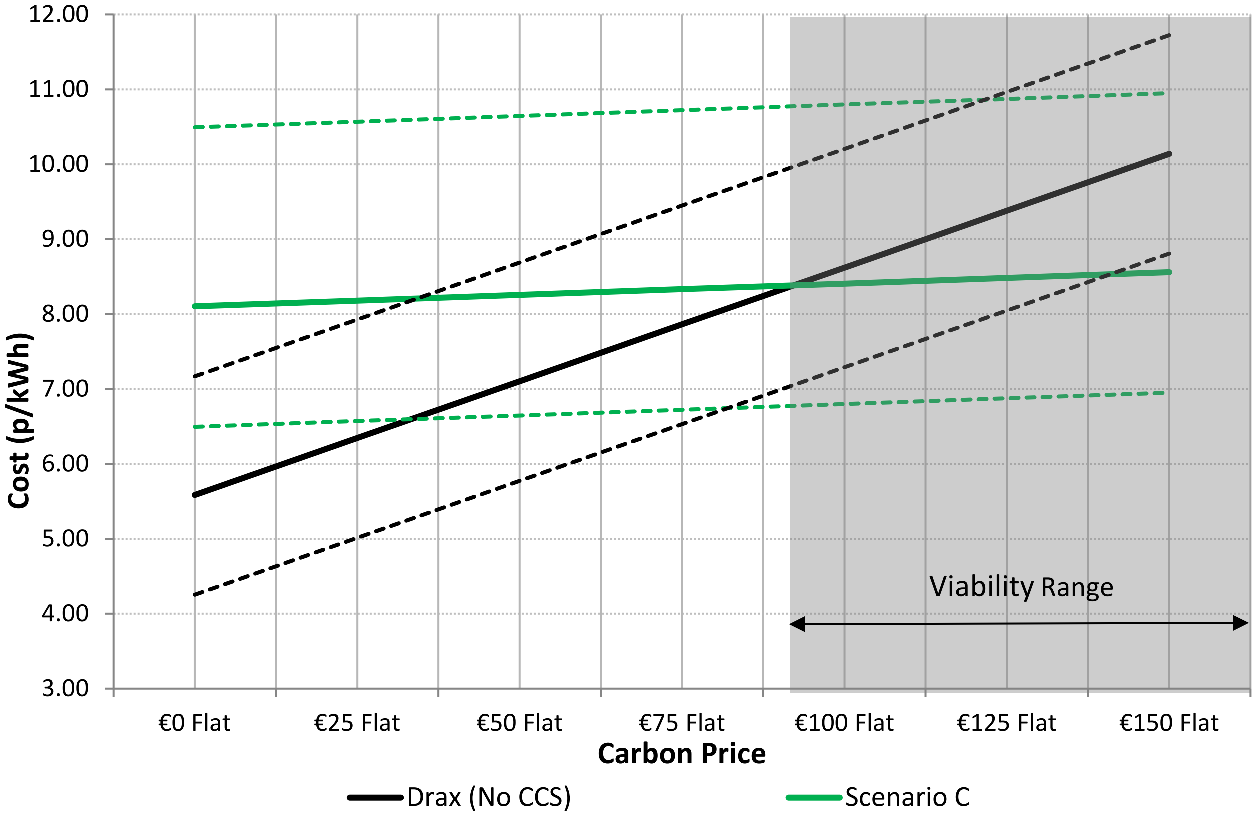
10.8.7. Figure 2 compares the results of the economic model for Drax (black line) with Scenario A (purple line) and Scenario B (red line), for the 1,800 MW case.

Figure 2 – Results for 1,800 MW Scenario A and Scenario B



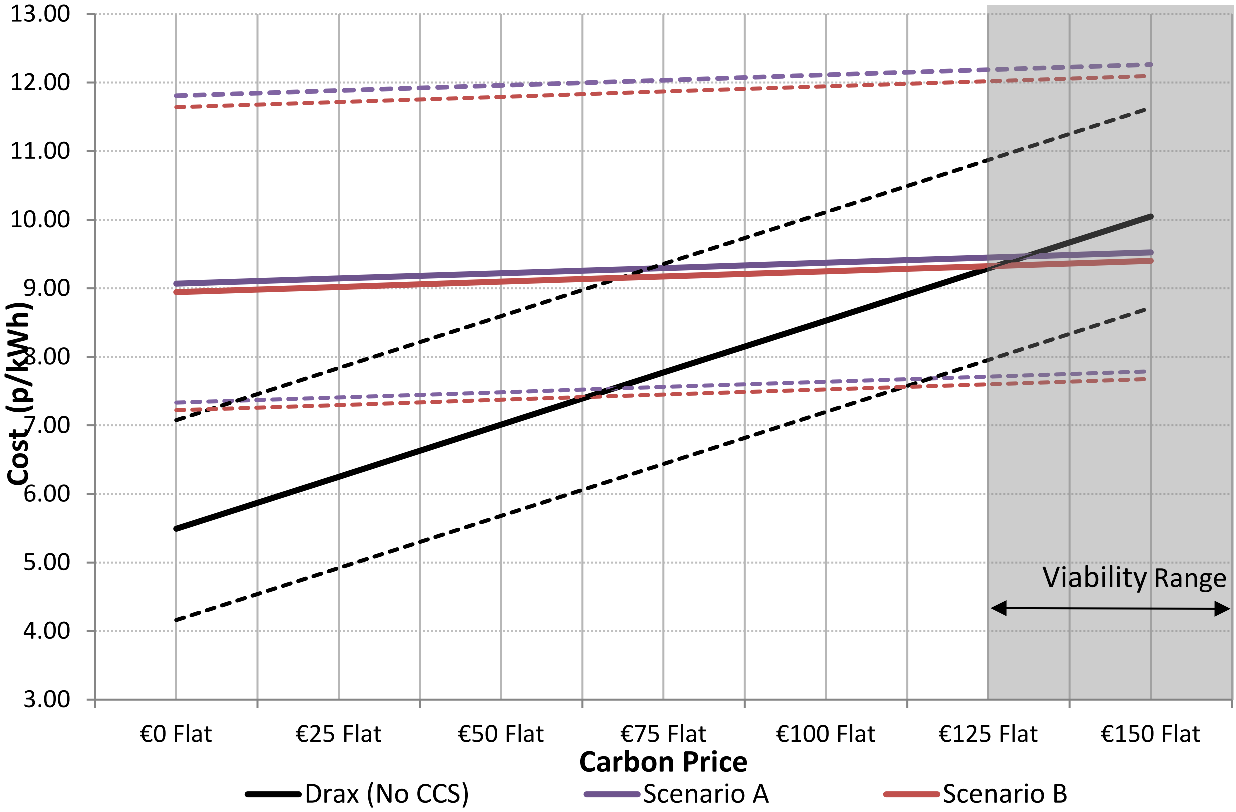
10.8.8. Figure 3 compares the results of the 1,800 MW economic model for Drax (black line) with Scenario C (green line).

Figure 3 – Results for 1,800 MW Scenario C



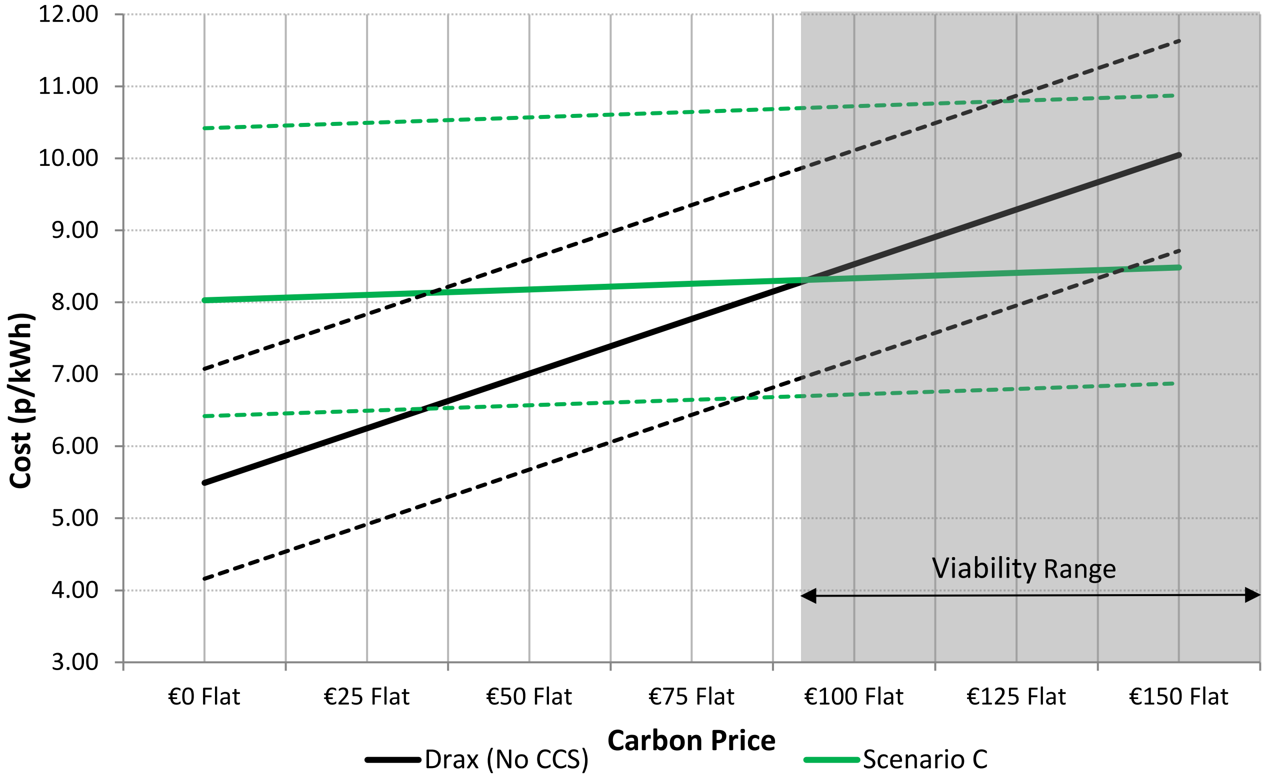
10.8.9. Figure 4 compares the results of the economic model for Drax (black line) with Scenario A (purple line) and Scenario B (red line) for the 3,600 MW case.

Figure 4 – Results for 3,600 MW Scenario A and Scenario B



10.8.10. Figure 5 compares the results of the 3,600 MW economic model for Drax (black line) with Scenario C (green line).

Figure 5 – Results for 3,600 MW Scenario C



10.9 Economic Assessment Conclusions

10.9.1. The results of the economic assessment indicate that the retrofitting of CO_2 capture equipment, transport and storage to Unit X and Unit Y becomes economic on the basis of carbon prices of approximately €125/t CO_2 for a First of a Kind Plant. Learning curve effects mean that the break-even carbon price should fall to nearer €90/t CO_2 for an "Nth of a Kind Plant", for both 1,800 MW and 3,600 MW scenarios.

10.9.2. However, it should be noted that the UK Carbon Price Floor is currently capped at £18/t CO_2, until 2021.

11 REQUIREMENT FOR HAZARDOUS SUBSTANCE CONSENT

11.1 Evaluation of the Potential Requirement for Hazardous Substances Consent

11.1.1. It is proposed that CO_2 transport onshore, from the proposed CCR land to the coastal transition point, is via an onshore CO_2 pipeline.

11.1.2. The presence of certain hazardous substances on, under or above land at or above set threshold quantities (Controlled Quantities) may require a HSC under the Planning (Hazardous Substances) Act 1990 (as amended) (Ref.11.1). The threshold quantities are set out in the Planning (Hazardous Substances) Regulations 2015 (as amended) (Ref. 11.2).

11.1.3. In addition to the requirement for a HSC, the presence of certain hazardous substances on, under or above land at or above the set threshold quantities may require the preparation of emergency plans under the Control of Major Accident Hazards Regulations 2015 (Ref. 11.3).

11.1.4. Accordingly, this Section evaluates the potential requirement for a HSC and emergency plans based on:

- The chemicals / substances involved in a gas fired power plant process;
- The chemicals / substances involved in a post-combustion CO_2 capture technology (using amine solvents); and
- The captured CO_2.

11.2 Chemicals / Substances involved in a Gas Fired Power Plant Process

Application of the Planning (Hazardous Substances) Regulations 2015.

11.2.1. Operation of a gas fired power plant would require the use natural gas as a fuel. The Planning (Hazardous Substances) Regulations 2015 (as amended) advise that the Controlled Quantity of natural gas is 15 tonnes. Natural gas will be delivered via a dedicated Gas Pipeline, and no natural gas will be stored on-site. As such, a HSC is not likely required on the basis of the chemicals / substances involved in a gas fired power plant process.

Application of the Control of Major Accident Hazards Regulations 2015 to the CO_2 Pipelines On-Site

11.2.2. The dedicated CO_2 pipeline on-site does not fall inside the scope of the Control of Major Accident Hazards Regulations 2015. As such, emergency plans are not likely required on the basis of the chemicals / substances involved in a gas fired power plant process.

11.3 Chemicals / Substances involved in a Post-Combustion CO_2 Capture Technology (using Amine Solvents)

11.3.1. As noted in section 4 (Proposed CO_2 Capture Technology), the feasibility of CCR for Unit X and Unit Y has been assessed on the basis on the best currently available technology, which, for CO_2 capture from flue gases (post-combustion CO_2 capture), is chemical absorption using amine solvents.

11.3.2. The most likely amine solvent is MEA, which is not normally present on gas fired power plant sites. The MEA that would be present at Unit X and Unit Y would either be stored as a pure substance, or be used in the CO_2 capture process as a solution. These are referred to as MEA substance and MEA preparation respectively.

11.3.3. In terms of MEA substance, the current classifications are XN R20/21/22 and C R34. These classifications translate as 'harmful' and 'corrosive'. In terms of MEA preparation, a solution of ≥ 25% would have the same classifications as MEA substance.

11.3.4. Accordingly, in terms of both MEA substance and MEA preparation, the current classifications are such that a HSC is not required. In addition, discussions have previously been held between WSP UK Limited and the DECC (now BEIS) Carbon Capture Readiness Team on the risks associated with MEA. In these discussions, DECC confirmed that the HSE did not consider MEA to be subject to any requirement for a HSC or be subject to any on-site storage limits.

11.4 Captured CO_2

11.4.1. As noted in the CCR Guidance, it may be that (during operation with CO_2 capture, compression, transportation and storage) dense phase CO_2 would be present on-site and within the CO_2 pipeline once the captured CO_2 is compressed in preparation for transport. Whilst dense phase CO_2 is not currently classified as hazardous, it is now recognised that an accidental release of large quantities of dense phase CO_2 could result in a major accident. As such, there is currently extensive ongoing research into the hazard potential of dense phase CO_2. The results of this ongoing research will inform future decisions on dense phase CO_2 and whether a classification review is necessary.

Application of the Planning (Hazardous Substances) Regulations 2015

11.4.2. In terms of the CO_2 capture and compression plant / equipment, it is anticipated that no CO_2 (gaseous or dense phase) will be stored on-site. As such, a HSC is not likely required on the basis of the captured CO_2 in the CO_2 capture and compression plant / equipment.

11.4.3. In terms of CO_2 transport, CO_2 (gaseous and / or dense phase) will be present in CO_2 pipelines on-site. Subject to the classification review, the CO_2 pipelines on-site may fall inside the scope of the Planning (Hazardous Substance) Regulations 2015 (as amended). However, until the classification is known and the information on the Controlled Quantity is available, it is not known whether the Planning (Hazardous Substances) Regulations 2015 (as amended) would apply. In this regard, the applicant is advised at some time in the future to hold informal discussions with the LPA about the potential issues surrounding dense phase CO_2, including the implications behind the possible presence of small amounts on site. These informal discussions are expected to continue until further information concerning the classification of dense phase CO_2 is available. This will ensure that there is early identification of any potential implications on the LPA's long term plan for the area. However, at this stage is it felt that no formal discussions or preparations are necessary.

Application of the Control of Major Accident Hazards Regulations 2015 to the CO_2 Pipelines On-Site

11.4.4. In terms of the CO_2 capture and compression plant / equipment, it is anticipated that no CO_2 (gaseous or dense phase) will be stored on-site. As such, emergency plans are not likely required on the basis of the CO_2 capture and compression plant / equipment.

11.4.5. In terms of CO_2 transport, the CO_2 pipelines on-site do not fall inside the scope of the Control of Major Accident Hazards Regulations 2015. As such, emergency plans are not likely required on the basis of the CO_2 pipelines on-site.

11.5 Conclusion on the Potential Requirement for Hazardous Substances Consent

11.5.1. On the basis of the proposed CO_2 capture technology and the current classifications of the chemicals / substances which are likely to be on site, it is concluded that a HSC is not required at this stage.

11.5.2. If a HSC is required at the point of construction / conversion to CO_2 capture, an application would be made at this stage. This is because any detailed information which would be required for the application will not be known until this stage.

11.6 Conclusion on the Potential Requirement for Emergency Plans

11.6.1. On the basis of the proposed CO_2 capture technology and the current classifications of the chemicals / substances which are likely to be on site, it is concluded that emergency plans are not required at this stage.

11.6.2. If emergency plans are required at the point of construction / conversion to CO_2 capture, these would be prepared at that stage. This is because any detailed information which would be required will not be known until development.

11.7 CCR Status and Full Development of CCS

11.7.1. As required by the CCR Guidance, this “Requirement for a Hazardous Substances Consent” will be reviewed on an ongoing basis as part of the CCR status report to be submitted within three months of full commissioning of Units X and then every two years (secured by requirements to the draft DCO, with a view to incorporating any developments into an updated design for the CO_2 capture plant for the Proposed Scheme.

12 CONCLUSION

12.1.1. This CCR Statement has been undertaken to support the application for a DCO for the Proposed Scheme.

12.1.2. It is considered that the information provided in this document has successfully demonstrated that:

- Sufficient space is available to accommodate the proposed CO_2 capture technology associated with Unit X and Unit Y operating in both OCGT mode and CCGT mode. This Study has shown that a land area of 17.28ha is required for the CCS equipment, whilst the DCO Application is securing a land area of 17.4 ha of land for CCS plant equipment, 1.7 ha for landscaping (woodland strips) around the new CCS Plant and 0.3 ha to allow diversion to public rights of way. The total extent of the land provided for Carbon Capture is shown in Figure 1 in Appendix 1;
- It will be technically feasible to retrofit and integrate the proposed CO_2 capture technology;
- There are suitable offshore CO_2 storage areas available;
- It will be technically feasible to transport the captured CO_2 to the offshore CO_2 storage areas; and
- It may be economically feasible, within the lifetime of the repowered units, to implement the proposed CO_2 capture technology (including transport and storage).

12.1.3. Accordingly, it is considered that the application for consent complies with the requirements of the CCR Guidance.

REFERENCES

- Ref. 1.1 Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013.
- Ref. 1.2 Directive on the geological storage of carbon dioxide (Directive 2009/31/EC) (the Carbon Capture and Storage (CCS) Directive) on 17 December 2008.
- Ref. 1.3 Large Combustion Plants Directive (2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants).
- Ref. 1.4 Carbon Capture Readiness (CCR): A Guidance Note for Section 36 Electricity Act 1989 Consent Applications (November 2009).
- Ref. 1.5 Planning Act 2008.
- Ref. 2.1 Directive on industrial emissions (integrated pollution prevention and control) (Directive 2010/75/EU) (the Industrial Emission Directive or IED).
- Ref. 2.2 ‘Overarching National Policy Statement for Energy (EN-1)’ (2011, DECC).
- Ref. 6.1 IEA Greenhouse Gas R&D Programme (IEA GHG), Retrofit of CO_2 capture to natural gas combined cycle power plants, 2005/1, January 2005.
- Ref. 8.1 ETI, D15: WP6 – CO_2 Storage Development Build-out 10113ETIS-Rep-22-03 March 2016.
- Ref. 8.2 ETI, D05: WP4 Report Appendix 5 – Site Assessments 10113ETIS-Rep-08-1.1 August 2015.
- Ref. 9.1 Capture Power Limited, White Rose Deliverable K35: Onshore Pipeline Route Plans January 2016.
- Ref. 9.2 Pipeline Safety Regulations 1996.
- Ref. 11.1 the Planning (Hazardous Substances) Act 1990 (as amended).
- Ref. 11.2 the Planning (Hazardous Substances) Regulations 2015 (as amended).
- Ref. 11.3 Control of Major Accident Hazards Regulations 2015.
- Ref. Appendix 3. 1 DTI Study 2006 “Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK” Report No. COAL R308 DTI/Pub URN 06/2027 (October 2006).

APPENDICES

APPENDIX 1: FIGURES

DO NOT SCALE

LEGEND:

CCR LAND BOUNDARY

REV	DATE	BY	DESCRIPTION	CHK	APP
01	23/04/2018	SPS	FIRST ISSUE	AF	TA

DRAWING STATUS:

SUBMITTED FOR REFERENCE

wsp

Westbrook Mills, Borough Road, Godalming, GU7 2AZ, UK
T+ 44 (0) 1483 528 400, F+ 44 (0) 1483 528 989
wsp.com

CLIENT:

drax

PROJECT:

DRAX REPOWER, CARBON CAPTURE READINESS FEASIBILITY STUDY

TITLE:

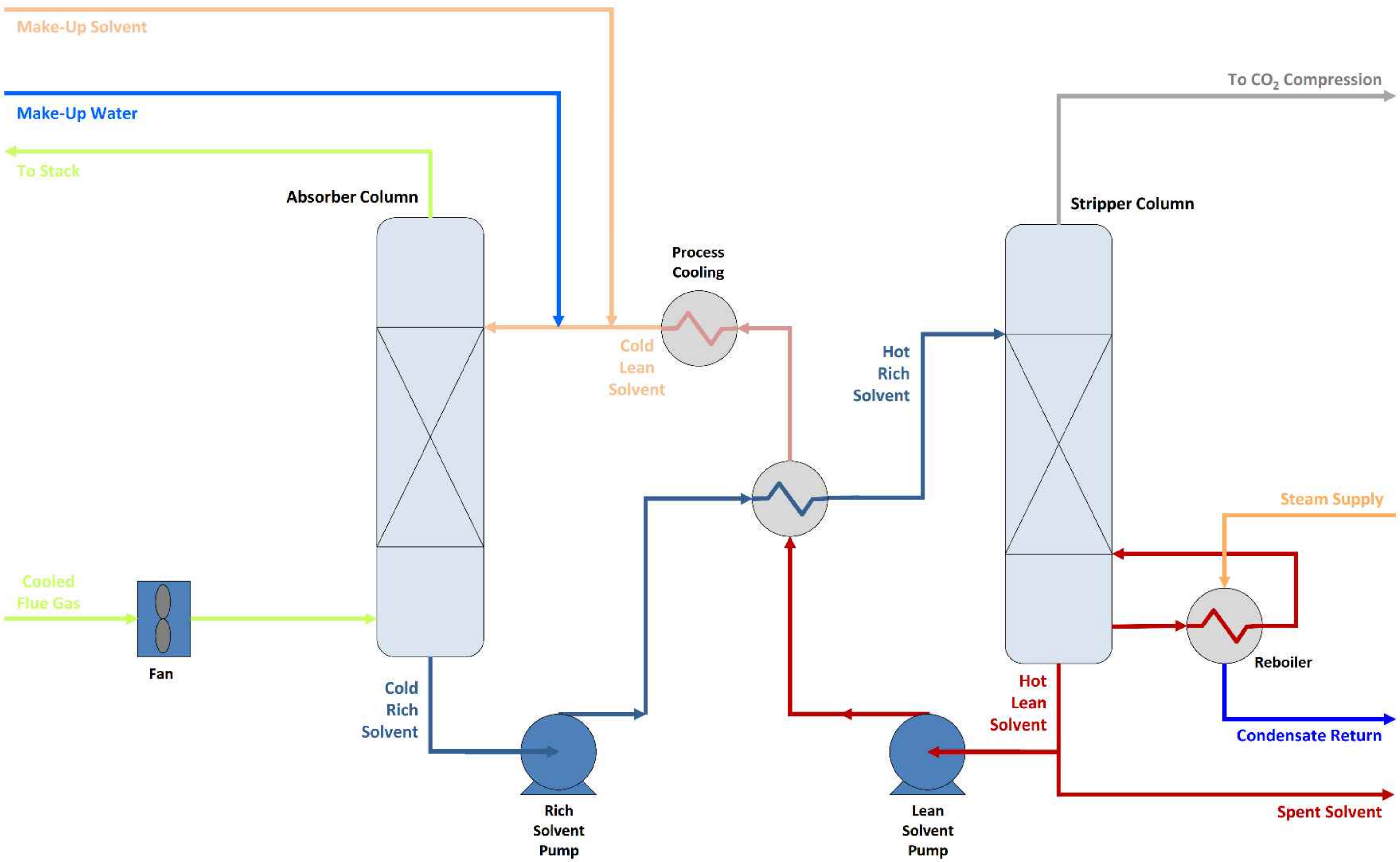
EXTENT OF CCR LAND FOR REPOWER PROJECT

SCALE @ A1:	CHECKED:		APPROVED:
1:4000	A.FODEN		T.ALDERSON
PROJECT No:	DESIGNED:	DRAWN:	DATE:
70037047	A.FODEN	S.SPINKS	23/04/2018

DRAWING No:	REV:
FIGURE 1	01

File name \\UK.WSPGROUP.COM\CENTRAL DATA\PROJECTS\70037XXX\70037047 - DRAX RE-POWERING DCO-YORKSHIRE\CAD\CCR\FIGURE 1_01.DWG

DO NOT SCALE



REV	DATE	BY	DESCRIPTION	CHK	APP
01	09/04/2018	SPS	FIRST ISSUE	AF	TA

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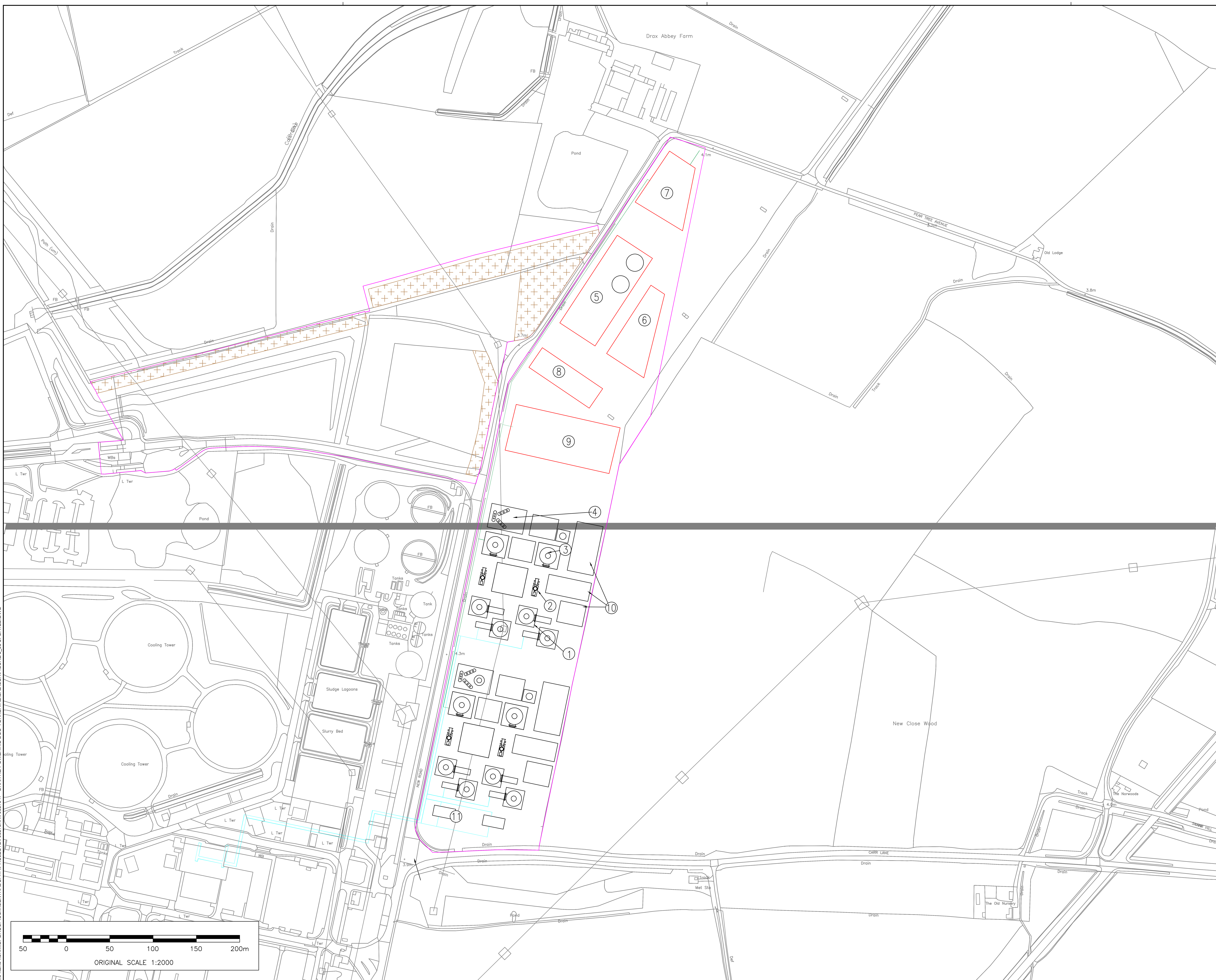
CLIENT:
drax

PROJECT:
DRAX REPOWER, CARBON CAPTURE READINESS FEASIBILITY STUDY

TITLE:
SCHEMATIC OF POST COMBUSTION CARBON CAPTURE

SCALE @ A3: NTS	CHECKED: A.FODEN		APPROVED: T.ALDERSON
PROJECT No: 70037047	DESIGNED: A.FODEN	DRAWN: S.SPINKS	DATE: 09/04/2018

DRAWING No: FIGURE 2 | REV: 01



DO NOT SCALE

LEGEND:

- WOODLAND STRIP
- CCR LAND BOUNDARY
- FLUE GAS DUCTING
- CO2 STREAM DUCTING

1. FLUE GAS COOLER
2. FLUE GAS BLOWER
3. ABSORBER COLUMN
4. STRIPPER COLUMN
5. CHEMICAL UN/LOADING STORAGE
6. ELECTRICAL POWER & STEAM/CONDENSATE AREA
7. CO_2 COMPRESSION PLANT AREA
8. ADMIN BUILDING
9. UTILITIES & BALANCE OF PLANT AREA
10. AREAS FOR COOLERS, HEAT EXCHANGERS, FLASH COMPRESSOR UNITS
11. AUXILIARY HRSG

NB. IT HAS BEEN CONFIRMED THAT THE FULL COOLING LOAD FOR THE CCP IS TO BE PROVIDED FROM THE EXISTING COOLING TOWERS. SPACE PROVISION FOR ANY ADDITIONAL COOLING WATER SUPPLY INFRASTRUCTURE (E.G. PUMPS, FILTERS, ETC.) IS PROVIDED IN THE UTILITIES & BALANCE OF PLANT AREA.

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03	20/02/2019	SPS	THIRD ISSUE UPDATED FOR EXAMINATION DEADLINE 7	RM	TA
02	27/09/2018	SPS	SECOND ISSUE PRIOR TO EXAMINATION	RM	TA
01	23/04/2018	SPS	FIRST ISSUE	AF	TA

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CLIENT:
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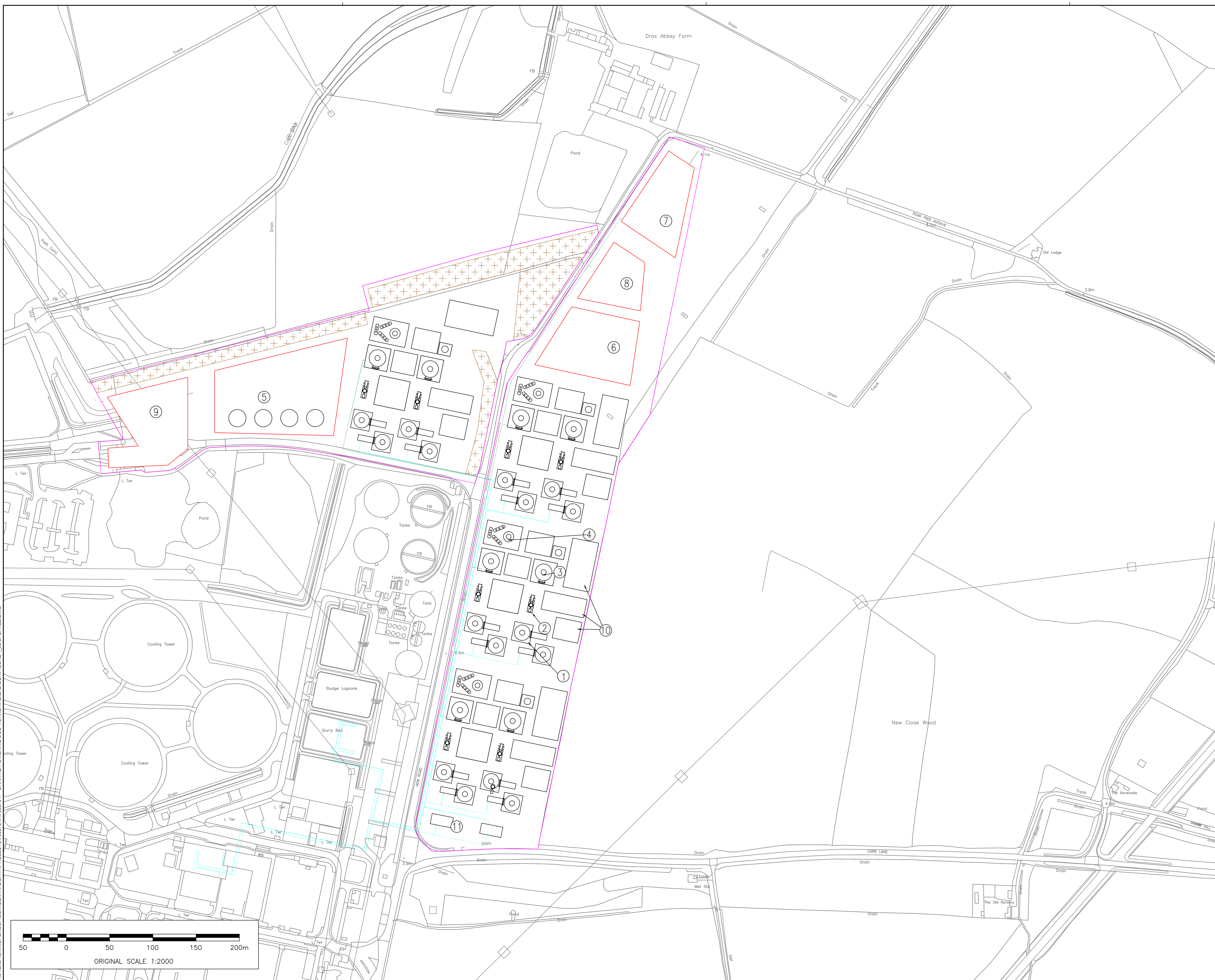
PROJECT:
DRAX REPOWER, CARBON CAPTURE READINESS FEASIBILITY STUDY

TITLE:
OUTLINE PLOT LEVEL PLAN 1800MW CASE

SCALE @ A1: 1:2000	CHECKED: A.FODEN		APPROVED: T.ALDERSON
PROJECT No: 70037047	DESIGNED: A.FODEN	DRAWN: S.SPINKS	DATE: 23/04/2018
DRAWING No: FIGURE 3			REV: 03

File name \\UK.WSPGROUP.COM\CENTRAL DATA\PROJECTS\700370XX\70037047 - DRAX RE-POWERING DCO-YORKSHIRE\CAD\CCR\FIGURE 3_03 UPDATED.DWG



DO NOT SCALE

LEGEND:

- WOODLAND STRIP
- CCR LAND BOUNDARY
- FLUE GAS DUCTING
- CO2 STREAM DUCTING

1. FLUE GAS COOLER
2. FLUE GAS BLOWER
3. ABSORBER COLUMN
4. STRIPPER COLUMN
5. CHEMICAL UN/LOADING STORAGE
6. ELECTRICAL POWER & STEAM/CONDENSATE AREA
7. CO_2 COMPRESSION PLANT AREA
8. ADMIN BUILDING
9. UTILITIES & BALANCE OF PLANT AREA
10. AREAS FOR COOLERS, HEAT EXCHANGERS, FLASH COMPRESSOR UNITS
11. AUXILIARY HRSGS

NB. IT HAS BEEN CONFIRMED THAT THE FULL COOLING LOAD FOR THE CCP IS TO BE PROVIDED FROM THE EXISTING COOLING TOWERS. SPACE PROVISION FOR ANY ADDITIONAL COOLING WATER SUPPLY INFRASTRUCTURE (E.G. PUMPS, FILTERS, ETC,) IS PROVIDED IN THE UTILITIES & BALANCE OF PLANT AREA.

REV	DATE	BY	DESCRIPTION	CHK	APP
03	20/02/2019	SPS	THIRD ISSUE UPDATED FOR EXAMINATION DEADLINE 7	RM	TA
02	27/09/2018	SPS	SECOND ISSUE PRIOR TO EXAMINATION	RM	TA
01	23/04/2018	SPS	FIRST ISSUE	AF	TA

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CLIENT: drax

PROJECT:
DRAX REPOWER, CARBON CAPTURE READINESS FEASIBILITY STUDY

TITLE:
OUTLINE PLOT LEVEL PLAN 3600MW CASE

SCALE @ A1: 1:2000	CHECKED: A.FODEN		APPROVED: T.ALDERSON
PROJECT No: 70037047	DESIGNED: A.FODEN	DRAWN: S.SPINKS	DATE: 23/04/2018

DRAWING No: FIGURE 4 REV: 03

File name \\UK.WSPGROUP.COM\CENTRAL DATA\PROJECTS\7003704X\70037047 - DRAX RE-POWERING DCO-YORKSHIRE\CAD\CCR\FIGURE 4_03 UPDATED.DWG

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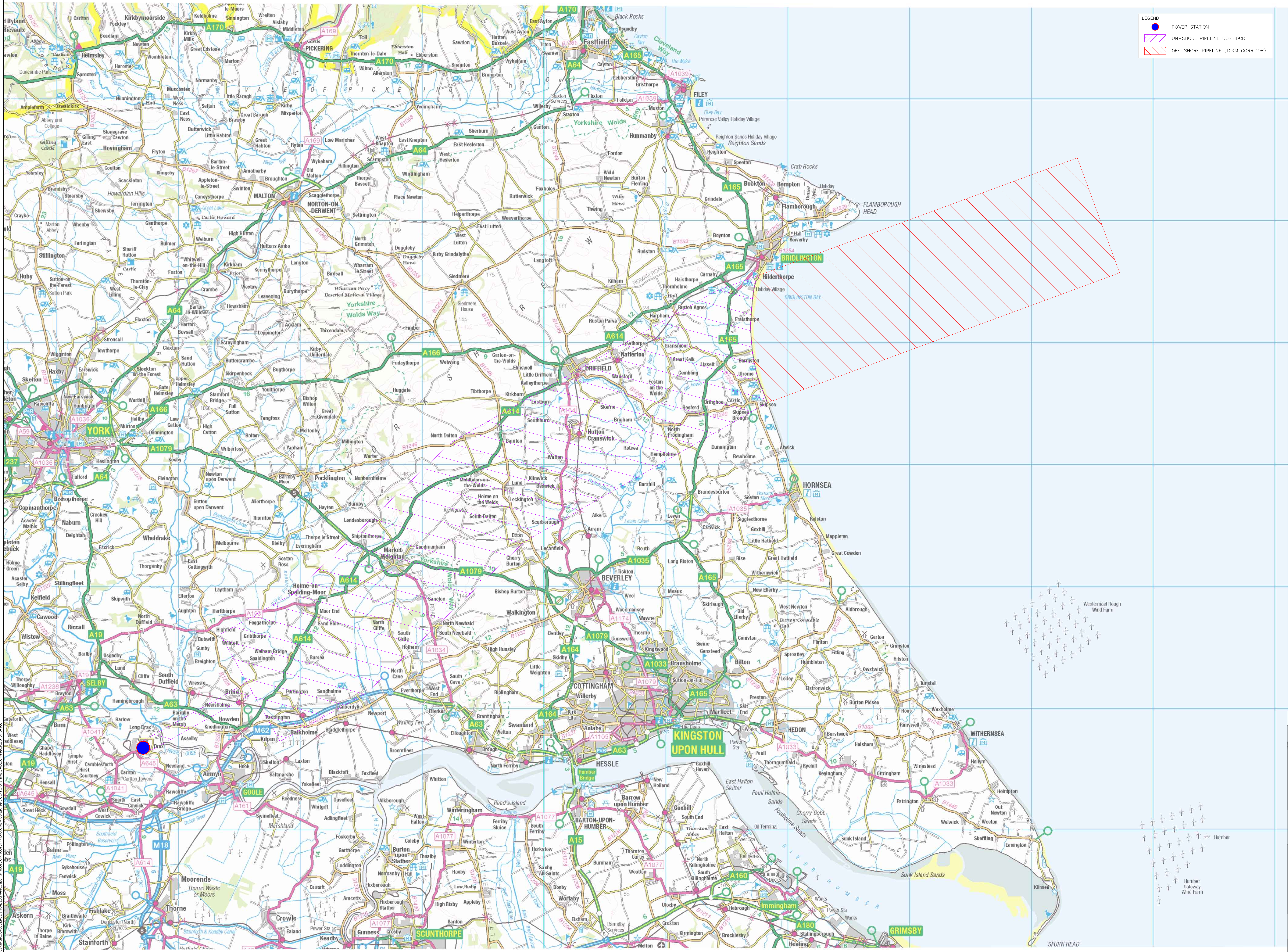

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CLIENT:

PROJECT: DRAX REPOWER, CARBON CAPTURE READINESS FEASIBILITY STUDY

TITLE: ON-SHORE CO2 PIPELINE

SCALE @ A0: 1:10000	CHECKED: A.FODEN		APPROVED: T.ALDERSON
PROJECT No: 70037047	DESIGNED: A.FODEN	DRAWN: S.SPINKS	DATE: 09/04/2018

DRAWING No: FIGURE 5 — REV: 01

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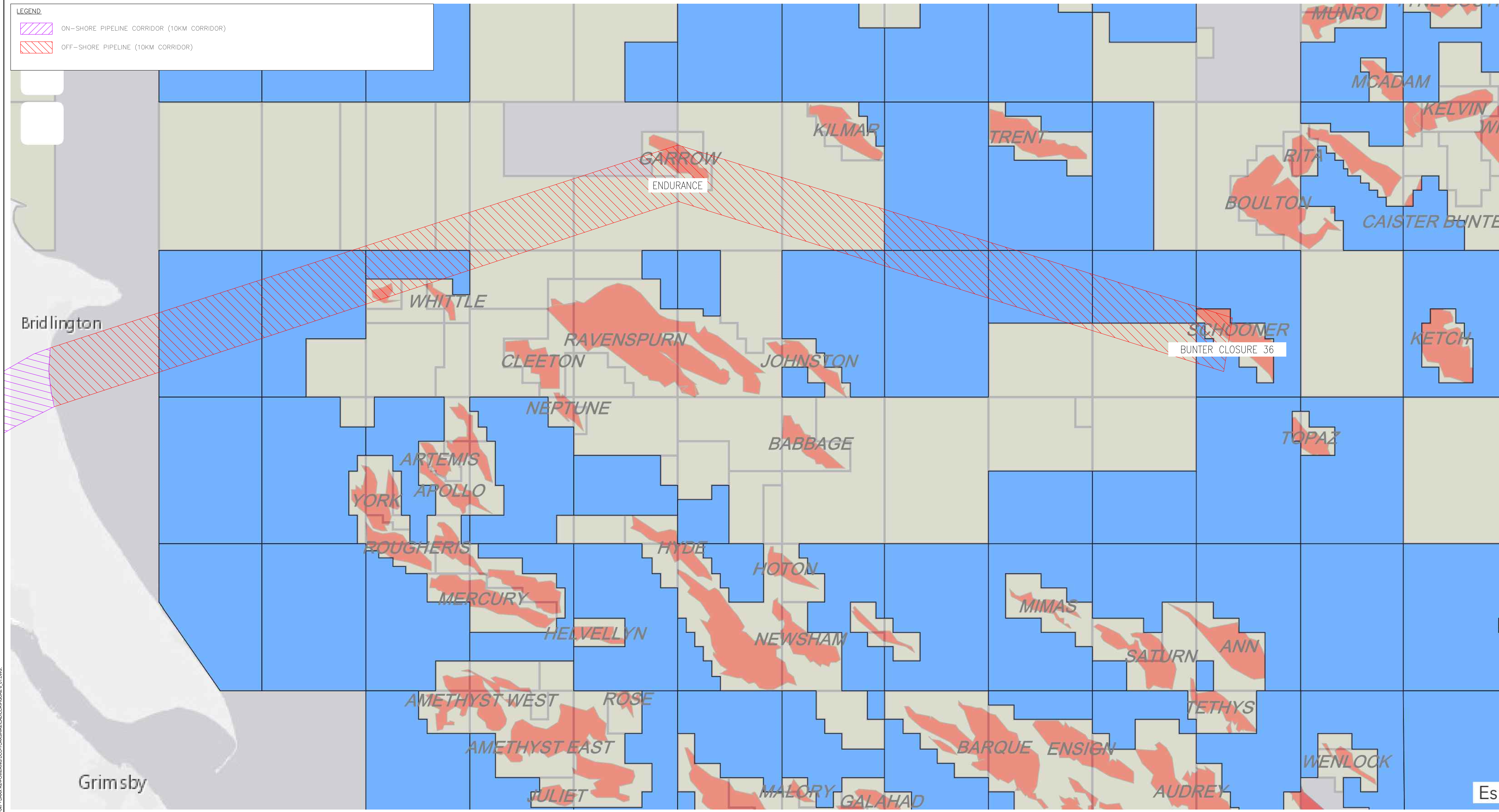
NOTES:
IMAGE TAKEN FROM OIL & GAS AUTHORITY (OGAUTHORITY.CO.UK)



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T+ 44 (0) 1483 528 400, F+ 44 (0) 1483 528 989
wsp.com

CLIENT:
drax

PROJECT:
DRAX REPOWER, CARBON CAPTURE READINESS FEASIBILITY STUDY

TITLE:
LOCATION OF IDENTIFIED POTENTIAL CO2 AREAS AND OFFSHORE PIPING

SCALE @ A0: NTS	CHECKED: A.FODEN		APPROVED: T.ALDERSON
PROJECT No: 70037047	DESIGNED: A.FODEN	DRAWN: S.SPINKS	DATE: 09/04/2018

DRAWING No: FIGURE 6

REV: 01

APPENDIX 2: RELEVANT SECTIONS OF EU DIRECTIVE

RELEVANT SECTIONS OF EU DIRECTIVE ON THE GEOLOGICAL STORAGE OF CARBON DIOXIDE

(47) The transition to low-carbon power generation requires that, in the event of fossil fuel power generation, new investments be made in such a way as to facilitate substantial reductions in emissions. To this end, Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants should be amended to require that all combustion plants of a specified capacity, for which the original construction license or the original operating licence is granted after the entry into force of this Directive, have suitable space on the installation site for the equipment necessary to capture and compress CO_2 if suitable storage sites are available, and CO transport and retrofit for CO_2 capture are technically and economically feasible. The economic feasibility of the transport and retrofitting should be assessed taking into account the anticipated costs of avoided CO_2 for the particular local conditions in case of retrofitting and the anticipated costs of CO_2 allowances in the Community. The projections should be based on the latest evidence; review of technical options and uncertainty analysis should also be made. The competent authority should determine whether these conditions are met on the basis of an assessment made by the operator and other available information, particularly concerning the protection of the environment and human health.

Article 32

Amendment of Directive 2001/80/EC

In Directive 2001/80/EC, the following Article shall be inserted:

"Article 9a

1. Member States shall ensure that operators of all combustion plants with a rated electrical output of 300 megawatts or more for which the original construction license or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide (*), have assessed whether the following conditions are met:

- suitable storage sites are available;
- transport facilities are technically and economically feasible;
- it is technically and economically feasible to retrofit for CO_2 capture.

2. If the conditions in paragraph 1 are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress CO_2 is set aside. The competent authority shall determine whether the conditions are met on the basis of the assessment referred to in paragraph 1 and other available information, particularly concerning the protection of the environment and human health.

(*) OJ L 140, 5.6.2009, p. 114".

RELEVANT SECTIONS OF EU DIRECTIVE ON INDUSTRIAL EMISSIONS (INTEGRATED POLLUTION PREVENTION AND CONTROL)

Article 36

Geological storage of carbon dioxide

1. Member States shall ensure that operators of all combustion plants with a rated electrical output of 300 megawatts or more for which the original construction licence or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide(1), have assessed whether the following conditions are met:

(a) suitable storage sites are available,

(b) transport facilities are technically and economically feasible,

(c) it is technically and economically feasible to retrofit for carbon dioxide capture.

2. If the conditions laid down in paragraph 1 are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress carbon dioxide is set aside. The competent authority shall determine whether the conditions are met on the basis of the assessment referred to in paragraph 1 and other available information, particularly concerning the protection of the environment and human health.

OJ L 140, 5.6.2009, p. 114.

APPENDIX 3: THE CCR REQUIREMENTS CHECKLIST

The CCR Requirements Checklist

Requirement	Description	Reference
C1 (Design, Planning Permissions and Approvals)	A pre-feasibility level conceptual capture retrofit study should be supplied for assessment showing how the proposed features would make adding post-combustion capture to the power plant technically feasible.	Section 7
	An outline plot level plan for the power plant retrofitted with CO_2 capture should be provided.	Figures 3 and 4 in Appendix 1
C2 (Power Plant Location)	The work undertaken on the CO_2 transport and storage should be referenced.	Section 8 / Section 9
	The exit point of gases from the curtilage of the power / CO_2 capture plant should be provided. A statement on how this affects the configuration of the power / CO_2 capture plant should be provided.	Section 9
C3 (Space Requirements)	The CCR Guidance states that "*space will be required 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 (e.g. space in steam turbine building for routing large low pressure steam pipe to amine scrubber unit);* *Extension and addition of balance of plant systems to cater for the additional requirements of the capture equipment;* *Additional vehicle movements (amine transport, etc.); and,* *Space allocation for storage and handling of amines and handling of CO_2 including space for infrastructure to transport CO_2 to the plant boundary.*"	N / A
	All of the provisions of a) to f) should be implemented. A statement describing how the space allocations were determined and how they will be met is required.	Section 6 / Figures 3 and 4 in Appendix 1
C4 (Gas Turbine Operation with Increased Exhaust Pressure)	The CCR Guidance states that *"the gas turbine (and upstream ducting and heat recovery steam generator (HRSG)) must be able to operate with the increased back pressure imposed by the capture equipment, or alternatively space must be provided for a booster fan."*	N / A
	A statement giving the expected pressure drop required for current commercial capture equipment	Section 7.3

Requirement	Description	Reference
	(together with a manufacturer's confirmation that the gas turbine can accommodate this) is required. In addition, for the expected pressure drop, a statement giving the anticipated effects on performance is required. Alternatively, a statement on the expected booster fan specification (and any associated space / installation requirements) is required.	
C5 (Flue Gas System)	The CCR Guidance states that *"space should be available for installing new duct work to enable interconnection of the existing flue gas system with the amine scrubbing plant and provisions in the duct work for tie-ins and addition of items, such as bypass dampers and isolation dampers, will be required as a minimum. If selective catalytic reduction (SCR) or other flue gas treatment is likely to be added at the time of retrofit then space for this should also be provided."*	N / A
	A statement describing the space and required flue gas system configuration (and how they would be implemented) is required.	Section 7
C6 (Steam Cycle)	A statement giving the steam pressure at the steam turbine IP / LP crossover (or other steam extraction point) is required. A statement on any post-retrofit equipment modifications / additions is required. A statement demonstrating that the steam cycle could be operated with capture using solvent systems with a range of steam requirements is required. A statement estimating the energy penalty involved in steam extraction is required. A statement estimating the energy penalty involved in steam extraction (from a purpose built steam cycle) is required.	Section 7
C7 (Cooling Water System)	The CCR Guidance states *"the amine scrubber, flue gas cooler and CO_2 compression plant introduced for **CO_2** capture increase the overall power plant cooling duty."*	N / A
	A statement of the estimated cooling water demands of the CO_2 capture plant (flows and temperatures) is required. A statement describing how the estimated cooling water demands of the CO_2 capture plant will be met is required. A statement describing how the cooling water will be supplied to the CO_2 capture plant is required. The chosen cooling water system should be justified.	Section 7

Requirement	Description	Reference
C8 (Compressed Air System)	The CCR Guidance states that *"the capture equipment addition will call for additional compressed air (both service and instrument air) requirements".*	N / A
	A statement of the estimated compressed air requirements of the CO_2 capture plant is required. A statement describing how the estimated compressed air requirements of the CO_2 capture plant will be met is required.	Section 7
C9 (Raw Water Pre-Treatment Plant)	The CCR Guidance states that *"space shall be considered in the raw water pre-treatment plant area to add additional raw water pre-treatment streams as required".*	N / A
	A statement of the estimated raw water pre-treatment requirements of the CO_2 capture plant is required. A statement describing how the estimated raw water pre-treatment requirements of the CO_2 capture plant will be met is required.	Section 7
C10 (Demineralisation / Desalination Plant)	The CCR Guidance states that *"a supply of reasonably pure water may be required to make up evaporative losses from the flue gas cooler and / or scrubber. Estimates of this water requirement should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary".*	N / A
	A statement of the estimated demineralised / desalinated water requirements of the CO_2 capture plant is required. A statement describing how the estimated demineralised / desalinated water requirements of the capture plant will be met is required.	Section 7
C11 (Waste Water Treatment Plant)	The CCR Guidance states that *"amine scrubbing plant along with flue gas coolers (if appropriate) provided for post-combustion CO_2 capture will result in generation of additional effluents".*	N / A
	A statement of the estimated waste water treatment needs of the CO_2 capture plant is required. A statement describing the expected post-treatment effluent quantity and composition is required. A statement describing the necessary space / other provisions due to the waste water treatment plant is required.	Section 7
C12 (Electrical)	The CCR Guidance states that *"the introduction of amine scrubber plant along with flue gas coolers,*	N / A

Requirement	Description	Reference
	booster fans (if required), and CO_2 compression plant will lead to a number of additional electrical loads (e.g. pumps, compressors)".	
	A statement of the estimated electrical requirements of the CO_2 capture plant is required. A statement describing how the estimated electrical requirements of the CO_2 capture plant will be met is required. This should include the necessary space provisions which will be required.	Section 7
C13 (Plant Pipe Racks)	The CCR Guidance states that *"installation of additional pipework after retrofit with carbon capture will be required due to the use of a large quantity of LP steam in the amine scrubbing plant reboiler, return of condensate into the water-steam-condensate cycle, additional cooling water piping and possibly other plant modifications."*	N / A
	A statement describing the anticipated additional pipe work is required. A statement describing the necessary space / other provisions due to the plant pipe racks is required.	Section 7
C14 (Control and Instrumentation)	A statement describing the anticipated additional control and instrumentation equipment is required. A statement describing the necessary space / other provisions due to the additional control and instrumentation equipment is required.	Section 7
C15 (Plant Infrastructure)	The CCR Guidance states that *"space to widen roads and add new roads (to handle increased movement of transport vehicles), space to extend office buildings (to accommodate additional plant personnel after capture retrofit) and space to extend stores buildings are foreseeable. Consideration should also be given as to how, during a retrofit, vehicles and cranes will access the areas where new equipment will need to be erected".*	N / A
	A statement describing the anticipated additional plant infrastructure (new or widened roads/ extension of office buildings / etc.) is required. A statement describing the necessary space / other provisions due to the additional plant infrastructure is required.	Section 7
Technical Assessment – Space Key Requirements	An outline plot level plan should be provided which is sufficiently detailed to show: The footprint of the power plant; The location of the capture plant;	Figures 3 and 4 in Appendix 1

Requirement	Description	Reference
of Paragraphs 18 to 19 of the CCR Guidance	The location of any compression equipment; The location of any chemical storage facilities; and The exit point of the CO_2 pipeline.	
	Basic calculations, using the estimated volumes of CO_2 which will have to be processed, could usefully be included.	Section 4
Technical Assessment – Retrofitting and Integration Key Requirements of Paragraphs 30 to 31 of the CCR Guidance	The pre-feasibility level conceptual capture retrofit study should make clear which capture technology is considered most appropriate for retrofit.	Section 5
	The pre-feasibility level conceptual capture retrofit study should provide sufficient detail to demonstrate that there are currently no known technical barriers to subsequent retrofit of capture technology.	Section 7
	The pre-feasibility level conceptual capture retrofit study should take into account the IEA Reference Document (IEA GHG 2007/4 "CO_2 Capture Ready Plants) Advisory Checklists.	Section 7
Technical Assessment – CO_2 Storage Areas Key Requirements of Paragraph 42 of the CCR Guidance	Identify a possible storage area, including delineating the geological extent of that area, and identify within that area at least two oil or gas / gas condensate fields (or saline aquifers) listed in the range of geological formations identified as "viable" or "realistic" in the DTI Study 2006 (Ref. Appendix 3.1) for CO_2 storage.	Section 8
	Provide a short summary (including an estimate) of the total volume of CO_2 likely to be captured and stored and an estimate of the potential total volume of CO_2 which could be stored in the area.	Section 8
Technical Assessment – CO_2 Transport Key Requirements of Paragraph 61 of the CCR Guidance	Provide sufficient detail to identify the preferred form and route for CO_2 transport onshore from the site exit point to the coastal transition point where the CO_2 goes offshore, including a map sufficiently large for the proposed route corridor to be clear.	Section 9
	Provide sufficient detail to identify the preferred form and route for CO_2 transport offshore from the coastal transition point to the identified CO_2 storage area, including a map sufficiently large for the proposed route corridor to be clear.	Section 9
	Demonstrate and confirm that there are no known barriers or unavoidable safety obstacles which exist within the identified onshore and offshore route corridors on the basis of current knowledge on CO_2 transport.	Section 9

Requirement	Description	Reference
	Suggest methods by which the environmental impacts on any unavoidable designated sites within the route corridor could be mitigated.	Section 9

APPENDIX 4: ANNEX C OF THE CCR GUIDANCE

Annex C

Environment Agency verification of CCS Readiness New Natural Gas Combined Cycle Power Station Using Post-Combustion Solvent Scrubbing

Capture Ready Features

Relevant text from IEA GHG Technical Report 2007/4 “CO_2 Capture Ready Plants” is used as a basis for the requirements in this list. See also IEA GHG report 2005/1 ‘Retrofit of CO_2 Capture to Natural Gas Combined Cycle Power Plants’.

Notes on evidence expected to be provided are shown in bold normal font. Where it is not possible or not considered necessary to provide the evidence this should be justified.

Post-combustion (amine scrubbing)

C1 Design, Planning Permissions and Approvals

Note C1: A pre-feasibility-level conceptual capture retrofit study should be supplied for assessment, showing how the proposed CCR features would make adding post-combustion capture technically feasible, together with an outline level plot plan for the plant retrofitted with capture.

C2 Power Plant Location

Note C2a: The work undertaken on CO_2 transport and storage should be referenced; the exit point of gases from the curtilage of the plant and how this affects the configuration of the capture equipment is the important aspect for the Environment Agency.

Note C2b: Health and Safety items in this section are outside the Environment Agency remit.

C3 Space Requirements

Space will be required for the following:

a) *CO_2 capture equipment, including any flue gas pretreatment and CO_2 drying and compression.*
b) *Space for routing flue gas duct to the CO_2 capture equipment.*
c) *Steam turbine island additions and modifications (e.g. space in steam turbine building for routing large low pressure steam pipe to amine scrubber unit).*
d) *Extension and addition of balance of plant systems to cater for the additional requirements of the capture equipment.*
e) *Additional vehicle movement (amine transport etc).*

f) *Space allocation for storage and handling of amines and handling of CO_2 including space for infrastructure to transport CO_2 to the plant boundary.*

Note C3: It is expected that all of the provisions in a-f above will be implemented, including the provision of space and access to carry out the necessary works at the time of retrofitting without excessive interruptions to normal plant operation. A statement describing how the space allocations were determined and how they will be met is required. Further details are requested in the following sections as appropriate. The space for capture equipment might be significantly reduced if flue gas recycling through the gas turbine is used to concentrate the CO_2, but to validate this option suitable demonstrations of its feasibility by the gas turbine supplier would be required.

C4 Gas Turbine Operation with Increased Exhaust Pressure

The gas turbine (and upstream ducting and heat recovery steam generator, HRSG) must be able to operate with the increased back pressure imposed by the capture equipment, or alternatively space must be provided for a booster fan.

Note C4: A statement is required giving the expected pressure drop required for current commercial capture equipment together with a manufacturer's confirmation that the gas turbine can accommodate this and any effects on the performance, or alternatively describing booster fan specification together with space and other installation requirements.

C5 Flue Gas System

Space should be available for installing new duct work to enable interconnection of the existing flue gas system with the amine scrubbing plant and provisions in the duct work for tie-ins and addition of items such as bypass dampers and isolation dampers will be required as a minimum. If selective catalytic reduction (SCR) or other flue gas treatment is likely to be added at the time of retrofit then space for this should also be provided.

Note C5: A statement is required describing the space and required flue gas system configuration for retrofit requirements and how they will be implemented.

C6 Steam Cycle

Note C6: A statement is required giving the steam pressure at the steam turbine IP/LP crossover (or other steam extraction point), together with a description of any post-retrofit equipment modifications/additions. It should be demonstrated that the steam cycle could be operated with capture using solvent systems with a range of steam requirements. The energy penalty involved in such steam extraction should be estimated and compared to theoretical minimum values (i.e. for extraction from a similar steam cycle that has been purpose-built for such steam extraction).

C7 Cooling Water System

The amine scrubber, flue gas cooler and CO_2 compression plant introduced for CO_2 capture increases the overall power plant cooling duty.

Note C7: A statement is required of estimated cooling water demands (flows and temperatures) with capture and how these will be met. It is expected that necessary space and tie-ins for cooling water supplies to post-combustion capture equipment will be provided and a description of these should be included.

C8 Compressed Air System

The capture equipment addition will call for additional compressed air (both service air and instrument air) requirements.

Note C8: A statement is required of estimated additional compressed air requirements together with a description of how these will be accommodated.

C9 Raw Water Pre-treatment Plant

Space shall be considered in the raw water pre-treatment plant area to add additional raw water pre-treatment streams, as required.

Note C9: A statement is required of estimated treated raw water requirements together with a description of how these will be accommodated.

C10 Demineralisation I Desalination Plant

A supply of reasonably pure water may be required to make up evaporative losses from the flue gas cooler and/or scrubber. Estimates of this water requirement should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary).
Note C10: A statement is required saying which of the above are needed and in what quantity and also describing how the necessary provisions will be implemented

C11 Waste Water Treatment Plant

Amine scrubbing plant along with flue gas coolers (if appropriate) provided for post combustion CO_2 capture will result in generation of additional effluents.

Note C11: A statement is required giving estimated additional waste water treatment needs and describing how the necessary space and any other provisions will be provided to meet expected demands.

C12 Electrical

The introduction of amine scrubber plant along with flue gas coolers, booster fans (if required), and CO_2 compression plant will lead to a number of additional electrical loads (e.g. pumps, compressors).

Note C12: A statement is required listing the estimated additional electrical requirements and describing space allocation in suitable

locations for items such as additional transformers, switching gear and cabling.

C13 Plant Pipe Racks

Installation of additional pipework after retrofit with capture will be required due to the use of a large quantity of LP steam in the amine scrubbing plant reboiler, return of condensate into the water-steam-condensate cycle, additional cooling water piping and possibly other plant modifications.

Note C13: It is expected that provision will be made for space for routing new pipework at the appropriate locations. A statement identifying anticipated significant additional pipework and describing space allocations to accommodate these is required.

C14 Control and Instrumentation

Note C14: It is expected that space and provisions for additional control equipment and cabling will be implemented. A statement identifying anticipated additional control equipment and describing space and other provisions to accommodate these is required.

C15 Plant Infrastructure

Space at appropriate zones to widen roads and add new roads (to handle increased movement of transport vehicles), space to extend office buildings (to accommodate additional plant personnel after capture retrofit) and space to extend stores building are foreseeable. Consideration should also be given to how, during a retrofit, vehicles or cranes will access the areas where new equipment will need to be erected.

Note C15: It is expected that the provisions above will be implemented. A statement identifying anticipated requirements and describing how they will be met is required.

Other technologies for post-combustion capture

C16 'Essential' Capture-Ready Requirements: Post Combustion Amine Scrubbing Technology based CO_2 Capture

The capture-ready requirements discussed in this section are the 'essential' requirements which aim to ease the capture retrofit of Natural Gas Combined Cycle power plants with post combustion amine scrubbing technology based CO_2 capture.

Note C16: The provisions covered in Notes C1-C15 can be adapted to include other liquid solvent mixtures for CO_2 capture that can be shown to have a reasonable expectation of being commercially available at the time of retrofit and for which reliable performance estimates are already available. A statement on where the requirements for capture readiness for such solvents differ from those for amine capture with respect to all of the relevant sections C1- C15 above is required, together with any additional CCR features or other actions proposed, to be added as addenda to the responses to Notes C1-C15. If making the plant capture ready for other solvents conflicts with the CCR requirements for amine

scrubbing then the impact on retrofitting amine scrubbing should be estimated and stated and the reasons for giving the other solvent priority should be listed and justified.

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