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Carbon Capture Readiness (CCR) Assessment

APFP Regulations ref. 5(2)(q)

Statera Energy Ltd

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Quality information

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Table of Contents

Figures

Tables

1. Introduction

Carbon Capture Readiness Assessment

1.1 This Carbon Capture Readiness (CCR) assessment has been prepared to support an application, under Section 37 of the Planning Act 2008, for an order granting development consent for a flexible generation plant (the Proposed Development) that is intended to provide up to 600 megawatts (MW) of electrical generation capacity on a fast response basis when called by the National Grid, together with up to 150 MW of battery storage capacity.

1.2 This report has been produced in order to demonstrate that it would be technically feasible to retrofit Carbon Capture technology in the future to the Proposed Development and therefore that the Proposed Development is Carbon Capture Ready (CCR). CCR needs to be demonstrable for all new combustion plant with a generating capacity at or over 300 MWe and of a type covered by the EU Industrial Emissions Directive[1], as set out in Section 4.7 of the Overarching National Policy Statement for Energy[2], and Chapter 3 of Part 1 of the Energy Act 2008 and other EU-derived domestic legislation which transposed Directive 2009/31/EC on the geological storage of carbon dioxide in relation to England and Wales[3].

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

The Developer

1.4 Thurrock Power is a subsidiary of Statera Energy Limited, a private British company that develops, builds and operates flexible electricity generating plant in the UK.

1.5 Statera Energy was established with the aim of delivering increased flexibility for the UK electricity system to assist in the transition to a low carbon economy in the expectation that renewable energy sources, such as solar and wind, will become the dominant form of generation of the future.

1.6 Thurrock Power will be a fully integrated developer, owner, and operator of the Proposed Development.

The Site

1.7 The Proposed Development is to be located on land south west of Station Road near Tilbury, Essex, within the administrative area of Thurrock Borough Council (TBC) and in the Thurrock Green Belt. The national grid reference (NGR) for the site is TQ662766.

1.8 The main development site currently comprises open fields crossed by three overhead power lines with steel lattice electricity pylons. It is immediately to the north of the existing Tilbury Substation and site of the decommissioned Tilbury coal fired power station, with the River Thames further to the south.

[1] To be interpreted as per Paragraph 6 of Schedule 1A to the Environmental Permitting (England and Wales) (Amendment) (EU Exit) Regulations 2019
[2] Whilst the National Policy Statements refer to the Large Combustion Plant Directive, this Directive was superseded by Directive 2010/75/EU of the European Parliament and the Council on industrial emissions (the Industrial Emissions Directive).
[3] Change of reference to the EU Directive on the Geological Storage of Carbon Dioxide, as prescribed by Paragraph 6(29)(d) of Schedule 1A to Schedule 1A to the Environmental Permitting (England and Wales) (Amendment) (EU Exit) Regulations 2019

The Proposed Development

1.9 The Proposed Development is intended to be constructed and operated as a flexible generation plant capable of providing up to 600 megawatts (MW) of electrical generation capacity, on a fast response basis, when called by the National Grid, together with up to 150 MW of battery storage capacity.

1.10 The Proposed Development may operate continuously or at intervals during the day and night, depending on the power generation and storage requirements of National Grid.

1.11 The site is to be powered by an array of reciprocating gas-fired internal combustion engines. Current assumptions are around the selection of either 48 x 12.5 MW or 32 x 18.4 MW gas engines. The baseline configuration is to install selective catalytic reduction (SCR) to reduce NO_x emissions to a performance level of approximately 20 mg/Nm^3.

Approach to demonstrating CCR compliance

1.12 The following approach has been used for this CCR assessment:

- A new generating station with output capacity of up to a nominal 600 MWe is proposed by Statera Energy Ltd. The plant is expected to supply power for up to 3500 hours per year, and consist of a bank of natural gas-fired reciprocating internal combustion engines (the prime movers). The intention is to build the plant out to an initial capacity below 299 MWe followed by a further development beyond 299 MWe, which would trigger CCR demonstration for the full 600 MWe;
- The site is to operate without heat recovery. No CHP requirement is considered as part of this study;
- Based on a high level conceptual design for the Proposed Development, a preferred carbon capture technology has been identified for potential future retrofit, based on thermal and process modelling, and current CCS technology availability. Additional future innovation opportunities have also been identified;
- The sizing and utility demand of the main CCS equipment that would be required has been established using thermal and process modelling. Site layouts have been prepared to show that the equipment would fit into the land currently identified to be retained for CCR purposes;
- Geological storage sites with storage capacities capable of accepting the carbon output from the Proposed Development over its design life were identified, utilising a study from the (former) Department of Trade and Industry (DTI)[4];
- Potential routes to transport the captured carbon dioxide (CO_2) from the site to the potential geological storage sites were identified, including consideration of potential use of shipping;
- An economic assessment that encompasses retrofitting carbon capture technology, transport and storage of CO_2 has been carried out for the CCS plant to estimate the price of allowances for CO_2[5] that is likely to be required to make the Development feasible, with CCS; and
- A high level assessment of the Health and Safety issues associated with the CCS plant was undertaken.

[4] Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK, 2006
[5] The EU Emissions Trading System Directive required a transposition deadline of 9 October 2019. On 31 October, the UK Government laid the Greenhouse Gas Emissions Trading Scheme (Amendment) (No 3) Regulations, SI 2019/1440, containing provisions meeting the mandatory transposition requirements and providing for other changes. The Government has consulted on an UK ETS (linked to the EU ETS), a stand-alone UK ETS and a carbon tax as options following the end of the transition period for the UK exiting the EU. Additional secondary legislation to cover the on-going arrangements is expected in 2020.

Report Structure

1.13 This report is structured as follows:

- **Section 1**: Introduction;
- **Section 2**: Legislative Background;
- **Section 3**: Description of the Proposed Development;
- **Sections 4 and 5**: Technical and Economic Feasibility Assessments; and
- **Section 6**: Health and Safety Assessment; and
- **Section 7**: Discussion of the proposed periodic review of this CCR Assessment.

2. Legislative Background

EU Directive on Geological Storage of Carbon Dioxide

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

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

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

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

The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013

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

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

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

2.7 In terms of the "CCR Conditions", CCR Regulation 2(2) states that:

> *"for the purposes of these Regulations, the CCR Conditions are met in relation to a combustion plant, if, in respect of all of its expected emissions of CO_2 –*
>
> *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)".*

2.8 Furthermore, CCR Regulation 3(1) states that:

"*The Secretary of State must not make a relevant consent order unless the Secretary of State has determined whether the CCR Conditions are met in relation to the combustion plant to which the consent order relates*".

2.9 CCR Regulation 3(3) states that:

"*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."

Planning Policy

2.10 Under Section 104(3) of the Planning Act 2008, Development Consent Order (DCO) applications for NSIPs are required to be determined by the Secretary of State in accordance with policy set out in the relevant National Policy Statements (NPS). As stated in the Overarching National Policy Statement For Energy:

"All applications for new combustion plant which are of generating capacity at or over 300MW and of a type covered by the EU's Large Combustion Plant Directive (LCPD) should demonstrate that the plant is 'Carbon Capture Ready' (CCR) before consent may be given. The [Secretary of State] *must not grant consent unless this is the case."*

2.11 In this regard, NPS EN-1 also states that:

"In order to assure the [Secretary of State] that a proposed development is CCR, applicants will need to demonstrate that their proposal complies with guidance issued ... in November 2009 or any successor to it."

2.12 The guidance referred to above is discussed in the following section.

Guidance

2.13 The Department of Energy and Climate Change (DECC) published guidance on CCR in November 2009[6]. The guidance makes it clear that, under the Government's CCR Policy, as part of their consent order application, applicants are required to:

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

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

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

- Technical Assessment of Sufficient Space for CCS Equipment: An assessment of appropriate space set aside to accommodate future carbon capture equipment is provided in **Section 4.1** of this report.
- Technical Assessment of Feasibility of CCS Retrofit: Annex C of the Guidance provides a detailed advisory checklist of the information to be included in a CCR Feasibility Study report on the technical assessment of the feasibility of retrofitting CCS equipment for a New Natural Gas Combined Cycle Power Station using Post-Combustion Solvent Scrubbing. It is noted that a specific checklist for the technology intended for the Proposed Development is not provided by the Guidance, however, for the purposes of this CCR Assessment, **Section 4.2** of this report deals with the technical response to the requirements of Annex C, as being of most relevance to the Proposed Development.
- Technical Feasibility of Storage of Captured CO_2: In accordance with the guidance, at least two fields or aquifers with an appropriate CO_2 storage capacity, which have been listed in either the "valid" or "realistic" categories in the DTI study, should be proposed as suitable CO_2 storage locations for the Development. Such sites are identified in **Section 4.3** of this report.
- Technical Feasibility of Transport of Captured CO_2: The Guidance states that the feasibility of any proposed site for a new combustion station will be influenced by the availability of transport routes to the proposed storage area. The technical feasibility of transporting the captured CO_2 to the storage area proposed for the Proposed Development is assessed in **Section 4.4** of this report.
- Economic Assessment of the Feasibility of CCS: The Guidance states that the main aim of the economic assessment is to provide an indication of the future likelihood of a retrofit of CCS equipment, CO_2 transport and storage of CO_2 being economically feasible at some stage during the proposed plant's operational lifetime. This is developed in **Section 5** of this report.
- Health and Safety Analysis: An analysis of Health and Safety issues associated with the CCS plant including consideration of whether a Hazardous Substances Consent may be required for the CCS plant proposed for the Proposed Development is provided in **Section 6** of this report.

2.15 It should be noted that pre-combustion techniques may lead to similar, or smaller, space requirements and have the potential to reduce or avoid the need for CO_2 transport by the 'upstream' removal of CO_2 from the fuel before combustion. This assessment is therefore a worst-case approach in terms of assessing the space requirements for CO_2 capture/ removal.

3. Description of the Proposed Development

Location

3.1 The proposed development is to be located on land south west of Station Road near Tilbury, Essex. The main development site is immediately to the north of the existing Tilbury Substation and site of the decommissioned Tilbury coal fired power station, with the River Thames further to the south.

3.2 The eastern edge of Tilbury is approximately 750 m west of the main development site, the village of West Tilbury is approximately 1.25 km to the north and East Tilbury village is approximately 2.1 km to the east. In addition, there are a number of individual or small groups of houses within around 800 m of the main development site boundary.

3.3 The nearest designated site is the Thames Estuary and Marshes Special Protection Area (SPA) and Ramsar site, approximately 2.6 km east of the main development site. The nearest Scheduled Monuments are Tilbury Fort (960 m south west) and 'Earthworks near church, West Tilbury' (730 m to the north).

Plant Description

3.4 Thurrock Power Ltd proposes to develop a flexible generation plant on land north of Tilbury Substation in Thurrock. The flexible generation plant will provide up to 600 megawatts (MW) of electrical generation capacity on a fast response basis when called by the National Grid, together with up to 150 MW of battery storage capacity.

3.5 The flexible generation plant may operate continuously or at intervals during the day and night, depending on the power generation and storage requirements of National Grid. Subject to agreement with the Environment Agency, the maximum annual operating time of the gas engines is not expected to exceed 4,000 hours.

3.6 The site is to be powered by an array of reciprocating gas-fired internal combustion engines. Current assumptions are around the selection of 48 x 12.5 MW gas engines. The baseline configuration is to install SCR to reduce NO_x emissions to a performance level of approximately 20 mg/Nm^3.

3.7 Reagent for the SCR may be either urea or ammonia solution that would be stored in tanks with appropriate containment bunds (and/ or in double-skinned tanks) to ensure no release to soil or the surface water drainage system in the event of a spillage or tank leak, and a leak detection system to alert the operator. If ammonia solution is used, which is a hazardous substance at high concentrations, no more than 50 tonnes at no more than 25% concentration would be stored on site, i.e. below the threshold at which the proposed development would be a lower-tier Control of Major Accident Hazards (COMAH) site or require a Hazardous Substances Consent.

3.8 The proposed development will be designed to operate for up to 35 years, after which ongoing operation and market conditions will be reviewed. If it is not appropriate to continue operating after that time, one or both elements of the development (gas engines or batteries) will be decommissioned.

Proposed Carbon Capture and Storage Technology

3.9 The current regulatory position is that the carbon capture plant would not be installed until CO_2 capture is either mandated or economically and technically viable. The current Emissions Performance Standard (EPS) set by the UK Government for new electricity generating stations is set at a level (450 gCO_2/kWh) that would not require CCS to be installed on new build gas-fired reciprocating engines. This EPS is proposed by UK Government to be maintained for consented plants until 2045.

3.10 There are three alternative carbon capture technologies available, namely:

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

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

3.12 As any CCS would have to be retrofitted to the Proposed Development at some point in the future, after several years of operation, this CCR Assessment has focussed on the potential use of post-combustion carbon capture, as this would be the most suitable for retrofitting to the Proposed Development, during its operational life.

3.13 The feasibility of CCS for the Proposed Development has therefore been assessed on the basis of the best currently available post-combustion carbon capture technology which, for carbon capture from combustion flue gases, would use an amine-based solution as the absorption medium. Statera Energy Ltd will keep under review the various pre- and post-combustion options.

Process Design Basis

3.14 The conceptual design of the carbon capture system proposed for the Proposed Development has been based on the assumptions and technical data presented in the 'Compliance Strategy' (AECOM, November 2018)[7] that is included as Appendix A to this document.

3.15 The conceptual design has been based upon the post-combustion modelling developed using the Thermoflow process modelling software, using a custom reciprocating engine model based on equipment manufacturer (OEM) datasheets with qualifying assumptions suitable for the level of detail of this study. In common with studies for other generating stations, a 90% CO_2 capture efficiency has been used as the basis. The modelling has determined that the heat demand of a carbon capture plant would exceed the heat available from the proposed development. Supplementary firing of the engine exhaust flue gases would be required to increase the heat available from the total exhaust gas and therefore meet the shortfall.

3.16 Preliminary sizing of a suitable fired duct burner to provide the necessary supplementary steam results in a higher flue gas temperature entering the carbon capture plant with an increase in the size of the direct contact cooler (DCC), which is required to remove incrementally more heat from the flue gas. Supplementary heat is required for the carbon capture plant as the exhaust gas from the reciprocating engines does not carry sufficient heat for 90% carbon capture. It is proposed that a duct boiler be added, increasing the carbon capture heat demand to 5178 kW while simultaneously increasing the available thermal duty to 5299 kW. The duct burner is considered more analogous to an electric heater than a standalone boiler as the incremental increase in emissions is also processed in the carbon capture plant.

[7] The Compliance Strategy reflects the approach developed to deal with 'open cycle' gas engines – a prime mover technology not reflected in existing guidance relating to CCR. As such, it represents a document that has helped to establish the principles for the undertaking of this CCR Assessment and the design/ operation evolution of the project since that time is not considered to have any material impact on approach set out in this document.

3.17 It is acknowledged that there would be an incremental increase in carbon dioxide emissions in the duct burner case. The net CO_2 emissions before capture increase from 70.8 kg/s to 75.3 kg/s, with net emissions to atmosphere post capture of increasing from 7.1 kg/s to 7.6 kg/s. This increment is deemed acceptable in order to achieve 90% carbon capture. The efficiency penalty for duct firing was calculated as 2.4 percentage points. Note this is net of approximately 2.2MW of auxiliaries per engine including the carbon capture equipment.

3.18 If duct firing is considered unacceptable, it is expected that the limit of carbon capture recovery would be approximately 68% by weight resulting in a net emissions release to atmosphere of 24.5 kg/s. Details of the impact of the duct burner has been discussed separately with the independent verifier [memo AECOM to IC Consultants dated 3 Apr 2019 – Appendix D].

3.19 This CCR assessment assumes that the higher capture efficiency of 90% is adopted since this represents the highest penalty on capture plant area, net thermal efficiency reduction and largest storage reservoir requirement.

3.20 A range of options have been considered to integrate the multi engine configuration into a reduced number of CCS trains. This study has been developed based on 12 engines per train resulting in 4 CCS trains (for the 48 gas engines scenario). The details of duct burner design and layout have not been developed beyond considering the overall concept requirements on a whole site and per unit basis. Plant optimisation would be carried out during later detailed design studies. The total plant exhaust flow for 48 engines of the proposed development has been found to be comparable to that of a single H-class turbine.

3.21 There are a number of significant differences between the basic power generation plant configurations of the CCGT and reciprocating gas engine technologies, aside from the operational differences between baseload and peaking duties. Studies carried out on H-class CCGT plants for recent UK projects have determined a typical steam load for this size of CCS plant, which would be raised using low pressure (LP) or intermediate pressure (IP) steam, typically from the IP/ LP crossover or cold reheat on a CCGT plant. Since the gas-fired reciprocating plant is open cycle and no CHP is planned, there will be no pre-existing steam available for the amine reboiler in the carbon capture plant.

3.22 Supplementary firing (as discussed above) will ensure that the heat is available to provide sufficient heat to achieve the full steam flow requirements of the amine regeneration process.

3.23 Operational issues related to the implementation of flexible CCS cycles will need to be addressed as the market develops and this is considered to present an economic rather than a technical challenge to future deployment of CCS. The future technical solution may be based upon an assumption that, where their operation is predictable, the gas engines can be run in bypass with the amine plant operating under warm standby conditions. Acid gas could then be introduced to the capture plant in such a way as to minimise the risk of tower foaming or flooding. However, it is recognised that use of warm standby increases the rate of amine loss and degradation and therefore increases operating costs for any such capture plant. Rapid and continuous changes to the CO_2 flows are a potential issue that may impact the capture process efficiency and economics and would need to be carefully considered in future studies.

4. Technical Assessment

Space

Footprint Estimate

4.1 At this stage, the final design of any potential CCS plant and equipment has not been developed and none would be undertaken until CCS was mandated to be required for the Site. Therefore, for the purposes of this CCR Assessment, a 'worst case' concept design and footprint area calculation has been estimated using the following sources of information:

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

4.2 On this basis the indicative 'worst case' total footprint has been estimated based on the calculations of 4 trains of CCS plant and the list of major equipment presented in Table 4.1. A conservative design margin is applied to allow for ductwork, piping, access and maintenance.

Table 4-1 Capture Plant Equipment List and Area per train

Equipment	Number of Pieces	Length / m	Width / m	Foot Print Area / m^2
DCC Filter Pump	2	1.5	1.5	5
DCC Circulating Water Pump	2	2.2	2.2	10
Blower	2	3.00	0.50	3.0
Solvent Make-up Pump	2	1	1	2.0
Rich Solvent Pump	2	3.5	2.5	17.5
Lean Solvent Pump	2	3.5	2.5	17.5
Wash Water Circulating Pump	2	1.5	1.5	4.5
Reflux Pump	2	1.5	1.5	4.5
Condensate to Deaerator Pump	2	2	2	8.0
HCT Recirculation Pump	2	2	2	8.0
Waste Water Sump Pump	2	1	1	2.0
Solvent Sump Pump	2	1.5	1.5	4.5
H_2SO_4 Solution Pump	2	1.5	1.5	4.5
NaOH Solution Pump	2	1.5	1.5	4.5
DCC column	1	9.5	9.5	90.3
Wash Water Cooler	1	12.73	2.4	30.5
Solvent Cross Exchanger	1	48.1	3.1	149.1
Lean Amine Cooler	1	32.6	1.8	58.7
DCC Water Cooler ACC	0	0.00	0.00	0.0
Reclaimer	1	7.00	4.25	29.8
Stripper Condenser	1	7.00	1.5	10.5
Air Cooled Coolers	1	88	53	4664
Re-boiler	1	19	3.4	64.6
Amine Storage Tank	1	2.75	0.00	5.9

Equipment	Number of Pieces	Length / m	Width / m	Foot Print Area / m^2
Overhead Accumulator	1	2.10	0.00	3.5
H_2SO_4 Solution Tank	1	1.40	1.40	2.0
NaOH Solution Tank	1	1.40	1.40	2.0
Absorber	1	9	9	81
Stripper	1	5	5	25
DCC Circulating Water Filter	2	0.5	0.5	1
Wash Water Filter	2	0.5	0.5	1
Lean Solvent Filter	2	7	4.2	59
Solvent Sump Filter	2	0.5	0.5	1
Waste Water Sump Filter	2	0.5	0.5	1
Activated Carbon Filter	2	4.5	4.5	41
Compressor Stage 1 Intercooler	1	8	2	16
Compressor Stage 2 Intercooler	1	8	2	16
Compressor Stage 3 Intercooler	1	8	2	16
Compressor Stage 4 Intercooler	1	8	2	16
Compressor Stage 5 Intercooler	1	8	2	16
Compressor Stage 1 Drum	1	2		3
Compressor Stage 2 Drum	1	1		1
Compressor Stage 3 Drum	1	0.7		0
Compressor Stage 4 Drum	1	0.5		0
Compressor Stage 5 Drum	1	0.3		0
CO_2 Compression Unit	1	11	7	77
CO_2 Dehydration Unit	1	10	20	200
Antifoam System	1	6	6	36
Instrument Air System	1	8	8	64
Nitrogen Blanketing System	1	5	5	25
subtotal				5902
Steam Plant	1	5.00	8.50	42.5
Sub-total				**5945**
Duct Work allowance (subject to layout)	1	56.25	4.00	225
		Total per CCS train incl duct work		**6170**
		Total per train including margin to allow for access, O&M		7404
		Total for plant (4 trains)		29616
		CO_2 capture footprint required m^2/MW (calculated based on outline design and 600MW plant capacity)		49.4
		Space retained on site for CCR		44,550
		Space retained on site for CCR m^2/MW		**74.3**

Source: AECOM

Footprint Comparison

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

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

4.5 In addition, the review by Imperial College further detailed additional scope for a reduction in the indicative CCS space requirement by 50% to 1.875 ha (including the reduction of 36%) considering technology advances and layout optimisation. This equates to 37.5 m^2/MW. However, the paper also states that such a reduction can only be justified following a detailed engineering design rather than only a linear scaling of this value.

4.6 For the purposes of assessing an open cycle gas-fired reciprocating installation, AECOM proposes that the benchmark footprint requirement is pro-rated for the change in overall cycle efficiency arising from the lack of a bottoming steam cycle. This leads to the benchmark area requirement for the CCGT plant being multiplied by a factor of ~1.43 in order to determine the effective combustion-generated component. As a consequence the required value increases from 37.5 m^2/MWe (for a CCGT) to 53.6 m^2/MWe (for the open cycle bank of reciprocating engines).

4.7 AECOM has calculated an estimated carbon capture site area of circa 29,616 m^2 (49.4 m^2/MW) from the indicative carbon capture plant component design shown in Table 4.1. To allow additional safety margins for intermittently operated gas engines, a minimum specific area of 53.6 m^2/MW is recommended to be retained for the proposed development to meet CCR requirements.

4.8 The Proposed Development has identified and secured a land option on a conservative space allocation of 44,550 m^2 (74.3 m^2/MW) for CCR purposes, which therefore exceeds the minimum requirement identified in this study.

4.9 Appendix B shows the indicative plant layout for the CCS plant within the space allocated on site for CCR purposes.

Retrofit

Introduction

4.10 To demonstrate that the Proposed Development has been designed so that it would be technically feasible to subsequently retrofit carbon capture equipment in the future to the entire 600 MWe capacity of the proposed generating station, the plant design has been assessed against the criteria presented in Annex C of the DECC CCR guidance note, modified by a factor of 1/0.7 to account for the difference in combustion-derived and waste heat-derived power between open and combined cycles.

Design, Planning Permissions and Approvals

4.11 The feasibility of CCS for the Proposed Development has been assessed on the basis of the best currently available technology, which for post combustion carbon capture from flue gases is capture using amine based absorption. Statera Energy Ltd will keep under review the various pre- and post-combustion options. An outline level plot plant for the plant is provided in Appendix B.

Power Plant Location

4.12 It is anticipated that the exit point for the captured CO_2 from the Proposed Development will be located to the North East of the site. The final location will be selected depending on the agreed method and route of CO_2 transportation, but will remain within the relevant area, as shown in Appendix B.

4.13 Where appropriate, pipe racks will be used to transfer the compressed and dehydrated CO_2 to the defined exit point. This is achievable as the pipe will have an internal diameter of circa 0.2 m assuming an allowable velocity of 3.5 m/s, due to the dense phase of the CO_2.

4.14 Further information on the transport and storage of captured CO_2 off-site is provided in Sections 4.3 and 4.4.

Space Requirements

4.15 The footprint presented in Section 3.3 of this report was used to prepare the plot plan presented in Appendix B that demonstrates that space has been allocated for the following:

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

4.16 In terms of the land required for laydown during construction of the CCS plant, the laydown area would be determined and secured at the time of installation and would depend on the year of construction. The Applicant estimates that approximately up to 3.9 ha of land for future laydown would be potentially required based on ~30% margin above the required plant area. This would be developed further in a detailed Construction Management Plan as part of the EPC Contractor's procurement and site management responsibility. It is envisaged that temporarily leased land would be used for laydown purposes. There is sufficient land availability in the locality of the site to be used for laydown.

Gas Engine Operation

4.17 The gas-fired engines may be unable to accommodate the increased backpressure due to the addition of CCS trains. Therefore, the design for the carbon capture plant includes a booster fan/blower to compensate for the pressure drop through the CCP (primarily in the absorbers, direct contact cooler and dampers) which is of the order of 140 mbar.

4.18 Based on the flue gas flow rate of around 193 m^3/s per train with a nominal pressure rise of 140 mbar a booster fan with a power rating of approximately 6.7MWe per train, or 26.6MWe in total has been included in the carbon capture plant power requirement.

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

Flue Gas System

4.20 The flue gas system has been developed based upon current studies for CCGT post-combustion capture and includes similar design elements. The following flue gas system is proposed for the carbon capture plant. The current layout is not optimised and consideration for a better site utilisation between the open cycle generating plant and the carbon capture plant could be made at a later stage.

Isolation and Bypass Dampers

- The flue gas exiting the prime movers is routed to a bypass or diverter damper, from where it may be directed either directly to a stack (e.g. during start up or fault conditions) but for normal operation through the CCS plant.
- This arrangement allows for the carbon capture plant and the gas reciprocating engine plant to have a reduced degree of mutual dependency, and to provide enhanced operability in safety and fault conditions. In the event of a major equipment fault such as the booster fan, the gas reciprocating engine plant can be switched to bypass mode until the fault is corrected. Plant safety issues are also more readily addressed. Safety studies and dynamic analysis of the flue gas path will be necessary at the design stage and will determine such parameters as fan control loops and the type and actuation speed of the bypass dampers. The location of the isolation and bypass damper with respect to the steam raising plant will be determined in future studies.

Flue Gas Cooling

- The absorption process requires a flue gas cooler to lower the flue gas temperature to around 45-55 °C to enhance the CO_2 chemical absorption and to minimise amine degradation. The flue gas is routed to a direct contact cooler (DCC), which quenches the flue gas to an acceptable temperature for absorption. A small slipstream of the circulating cooling water is routed through the DCC Water Filter to remove particulate build-up. A portion of this particulate free stream is returned to the DCC; the other portion is directed to a wastewater treatment plant. Cool, saturated, flue gas from the DCC is extracted through the Blower which is required to overcome the frictional losses in the ducting, Gas to Gas Heat (GGH) Exchangers, DCC and Absorber.
- A gas-to-gas Ljungström type heat exchanger could be included prior to the DCC. Heat would be transferred from the hot untreated flue gas stream to the cold treated purified flue gas stream. This heat exchanger would reduce the duty of DCC and would improve the dispersion of the treated flue gases into the atmosphere. The heat exchanger has not been sized for this study but could be considered, if required, during detailed design.

CO_2 Absorber

- The cooled flue gas from the DCC is fed to the bottom of the counter current Absorber where CO_2 in the flue gas is absorbed by the solvent. Flue gas enters near the bottom of the Absorber and flows upward through packed beds. CO_2 reacts chemically with the solvent and is absorbed into the bulk solution. Rich solvent leaves the bottom of the Absorber and is transferred to the Stripper by the Rich Solvent Pump.
- Stripped flue gas, vaporized amine-based solution and water travels through a chimney tray and enters the top packed bed. This third packed bed is the wash section of the column, where wash water is used to recover the vaporized amine and water. A Wash Water Circulating Pump circulates the wash water between the Absorber and Wash Water Cooler.
- Flue gas is vented to the atmosphere via the stack on top of each Absorber at a temperature of approximately 37°C. No evaluation of the potential frequency of visible plumes from the final flue gas discharge from the CCS plant has been undertaken at this stage. This will be evaluated at the detailed design stage and if required appropriate mitigation employed.

CO_2 Stripper

- Rich solvent leaves the bottom of the Absorber and is routed to the rich to lean amine solution cross heat exchanger which increases the efficiency of the process by heating the rich amine to >100 °C using the heat in the lean amine stream from the Stripper. The

preheated rich amine enters the Stripper below the wash section of the column through a liquid distributor and flows down through the packed beds counter-current to the vapour from the Reboiler releasing the absorbed CO_2. The lean amine from the bottom of the Stripper is transferred to the rich to lean solution cross heat exchanger, where it is cooled against the rich amine from the absorber train.

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

Stripper Overhead Condenser

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

Amine Reclaimer

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

Centrifugal Compressor

- The wet CO_2 from the Stripper Reflux Drum is routed to an intercooled CO_2 Compressor. The captured CO_2 is compressed to meet the delivery pressure required for the pipeline.

Dehydration Unit

- A dehydration package is needed for reducing the water content in the CO_2 stream to 50 ppm (wt.) to assure that condensation in the CO_2 pipeline does not occur. At this concentration, the dew point is at approximately -46 °C, which makes condensation unlikely.
- A glycol-based dehydration package, being a mature technology in natural gas dehydration processes, is well suited to be used for this application. For the expected operating temperatures, Triethylene-glycol (TEG) is better than other glycol-based absorbents. This package is installed after the second intercooling stage of the CO_2 compression package. That way, the pressure remains below the critical point for CO_2.
- It is considered that there are no foreseeable technical barriers to retrofitting and integration of carbon capture plant into the flue gas system.

Steam Cycle

4.21 A supply of 29 kg/s of low pressure (3 bara) steam at 140 °C (62.1 MW heat) per train is required for the amine regeneration process. The baseline gas reciprocating plant does not include any heat or steam raising equipment and therefore a waste heat recovery plant will be required. This waste heat plant shall require further supplementary firing (as discussed earlier) to raise the 290°C engine exhaust stream temperature to approximately 375°C (and suitable for the raising of the required steam flow). This additional gas fuel input increases the CO_2 concentration in the exhaust stream and, in turn, the duty of the CCS plant.

Cooling System

4.22 The amine-based CCS process has a considerable cooling duty, which is estimated at 125.8 MWth per train. The main cooling demands within the CCS process comprise:

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

4.23 It is proposed for the basis of this study that the carbon capture plant uses air-cooled fin-fan coolers as this represents the most footprint-demanding technology. The illustrative site layout in Appendix B includes provisions for fin-fan coolers and has been sized based on air cooling rather than water cooling. Sizing calculations have assumed a higher ambient temperature of 25°C to conservatively determine the space provision required. Alternative technologies such as hybrid cooling towers would have a significant reduction on the on-plot size required. The final selection of cooling technology would be in a future detailed engineering stage for the carbon capture plant.

Compressed Air System

4.24 There is no requirement within a standard amine-based CCS plant for any compressed air for process purposes, but only for the supply of instrument air and general service air to the CCS plant. This requirement shall be determined at the detailed design stage. Depending on the exact requirements, e.g. the number and duty of air actuated valves; this may be met by connecting to the compressed air services of the Proposed Development, or by installing a new dedicated system for the CCS plant.

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

Water Treatment

Raw Water

4.26 The CCS plant will only have a small demand of make-up raw water. This water shall make up for small losses in of the amine/water solution loop caused by amine degradation or carry over; additional water will be required for cooling albeit only as top up water to the closed loop fin-fan coolers.

4.27 The process will generate water by condensation of moisture from the flue gas in the DCC and the CO_2 compressor inter stage cooler knock-out drums. This water will be slightly acidic due to dissolved CO_2 but would be suitable for treatment in a dedicated CCS WTP.

Demineralised Water

4.28 At present this is estimated to be approximately 14.3 tonne/hr peak per train as per Fluor's Econoamine FG process, although there are studies[8] which suggest that demin water quality is not required for the amine solution make-up water and only good quality water is required. Should demin water quality be required, there is sufficient space in the proposed layout to include a dedicated water treatment plant which is estimated to take up around 8 m x 12 m.

Waste Water

4.29 The detailed design of the carbon capture plant will include appropriate surface water drainage systems including oil interceptors as necessary, consistent with surface water drainage systems for power stations in general. Space provision for site drainage e.g. surface water and process water drains has been included in the footprint allocation for each piece of equipment.

4.30 Waste water will be generated from the cooling of the flue gas resulting in partial condensation of water vapour within the direct contact cooler. The volume of wastewater generated will vary with ambient conditions but is not likely to exceed 30 t/h per train, depending on the gas reciprocating engine selected. Table 4.2 lists the waste water treatment requirements.

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

Table 4-2 Waste Water Output

Parameter	per train
Drain Water from CO_2 compression CCS plant per train /kg/s	4
DCC drain /(kg/s)	3.9

Source: AECOM

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

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

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

4.34 It is proposed that the detailed design stage for the carbon capture plant include an assessment whether it is appropriate to combine the condensed water stream with the waste water stream. Combining the streams may reduce the amount of neutralisation required at the waste water treatment plant as the DCC drain will be slightly caustic, while the condensate drain will be slightly acidic. The detailed design would also identify whether any modifications to any existing effluent treatment system were required at that time.

Electrical

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

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

4.36 The total power requirement of the CCS plant is approximately 18.9 MW per train. Further detail of individual users is presented in Table 4.3.

Table 4-3 CCS Electrical Power Consumption (per train)

CCS Equipment Item(s)	Estimated Electrical Consumption (MW)
CO_2 compressor	6.1
Booster fan	6.7
Fin fan coolers	2.8
Cooling water circ pumps	2.4
Amine circ pumps	0.5
Misc	0.4
Total (per train)	**18.9**

Source: AECOM

4.37 It is currently proposed that the electrical demand of the CCS plant is taken directly from the output of the engines, reducing the export capacity to the National Grid accordingly.

Pipework

4.38 Space provision for plant pipe racks has been included in the footprint allocation for each piece of equipment and is shown in Appendix B.

Control and Instrumentation

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

Plant Infrastructure

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

4.41 The provision of space for additional plant infrastructure is illustrated in the illustrative site layout in Appendix B.

4.42 The site is accessible from the existing road network and is not considered to have any access constraints which could impede any future construction activities. The final provisions for plant infrastructure will be detailed in the final design of the carbon capture plant.

CO_2 Storage

4.43 The maximum theoretical volume of CO_2 anticipated to be captured during the lifetime of the Proposed Development is 24 million tonnes (assuming approximately 0.9Mt CO_2/year from the plant units, an average lifetime capacity factor of 40% and a 25-year design lifetime post abatement).

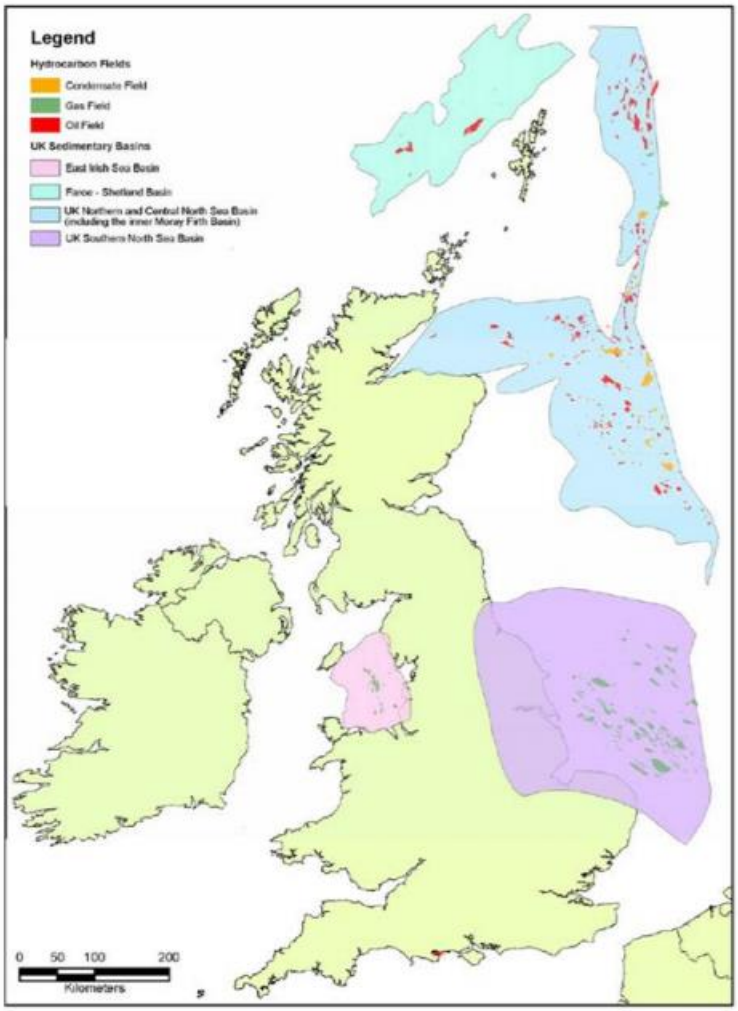
4.44 The UK's major potential sites for the long-term geological storage of CO_2 are offshore depleted hydrocarbon (oil and gas) fields and offshore saline water-bearing reservoir rocks / aquifers.

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

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

4.46 As shown in Figure 4.1 most of the UK's large offshore oil fields are mainly in the Northern and Central North Sea Basin. The UK's offshore gas fields occur mainly in two areas: the Southern North Sea (SNS) Basin and the East Irish Sea Basin. The DECC CCR guidance suggests that the simplest and most appropriate means of demonstrating there are "no known barriers" to CO_2 storage is by delineating on a map a suitable storage area in either the North Sea or Irish Sea (Morecambe Bay). Within this delineated area, there should be at least two fields or aquifers, with an appropriate CO_2 storage capacity, which have been listed in either the "valid" or "realistic" categories in the DTI's 2006 study of UK Storage Capacity "Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK", October 2006 (DTI Study 2006), which is provided in Annex 1D of the CCR Guidance.

Figure 4-1 Location of offshore hydrocarbon fields and hydrocarbon bearing basins[9]



4.47 The Proposed Development is located in the south east of England therefore the nearest hydrocarbon fields to the Proposed Development are located in the Southern North Sea Basin.

4.48 Based on the DTI Study 2006, due to their location and capacity the Hewett (L Bunter and U Bunter) and Leman gas fields in the South North Sea Basin are potential storage areas for the CO_2 captured from the Proposed Development. Based on the total storage requirements of the Proposed Development, Table 4-4 illustrates the percentage storage requirements on these two gas fields.

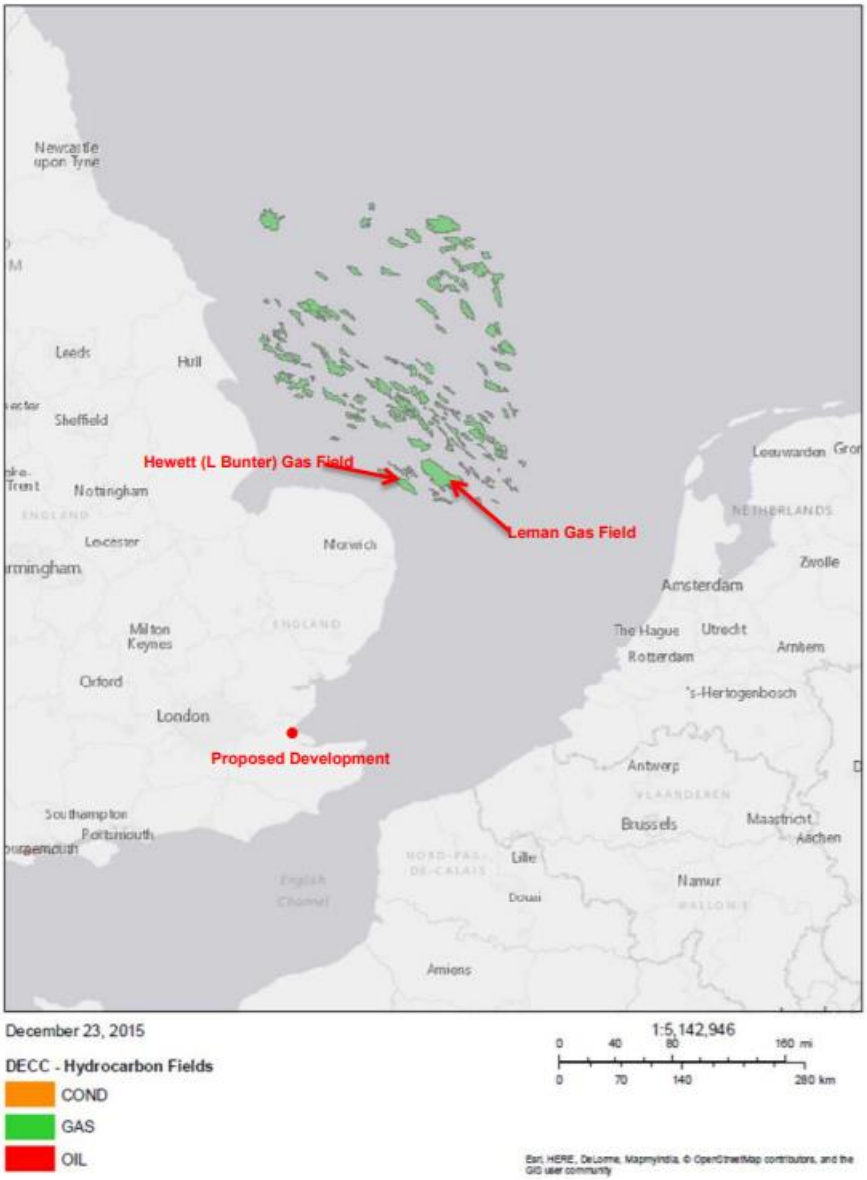
[9] (British Geological Survey (BGS) (October 2006) Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK (DTI/Pub URN 06/2027), prepared or the UK Department of Trade and Industry, now the Department of Business Enterprise and Regulatory Reform.)

Table 4-4 Capacity of Proposed Geological Storage Areas

Field Name	Total Volume of CO_2 emitted by proposed development / 10^6 tonnes	Capacity of Geographical Storage Area / 10^6 tonnes	% of capacity
Hewett (L Bunter and U Bunter) Gas Field	24	237	10%
Leman Gas Field	24	1203	2%

4.49 The location of these storage areas is illustrated on Figure 4.2 below

Figure 4-2 Location of offshore hydrocarbon fields in the SNS[10]



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

4.50 In accordance with the DECC guidance, the gas fields listed in Table 4-5 are identified as 'realistic' storage locations in the DTI report (British Geological Survey (BGS) (October 2006) Industrial Carbon Dioxide Emissions and Carbon Dioxide Storage Potential in the UK (DTI/Pub URN 06/2027), prepared or the UK Department of Trade and Industry, now the Department of Business Enterprise and Regulatory Reform.

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

4.52 It is recognised that in the future there may be competing interest for the identified CO_2 storage sites, as other carbon capture and storage projects become operational. It is also recognised that other CCR applications may also have identified the same geological fields for CO_2 storage capacity. According to the UK Government Website[11] the Hewett Bunter gas field has three existing potential consented users comprising:

- Damhead Creek 2 requirements of 84 Mt CO_2;
- Willington C (200 Mt CO_2 March 2011);
- Gateway Energy Centre (GEC) (74 Mt CO_2 August 2011).

4.53 This gives a currently consented total of 358Mt and a remaining CO_2 storage capacity of 1 Mt of CO_2 when considering the combined capacity of the two Hewett Bunter Gas Fields (359 Mt CO_2). These figures are revised below.

4.54 It is understood from the Damhead Creek 2 published information of Feb 2016 that current estimates have been revised to

- Damhead Creek 2 140 Mt CO_2;
- Willington C 200 Mt CO_2;
- Gateway Energy Centre (GEC) 84 Mt CO_2.

4.55 The preferred CO_2 storage area for GEC has been changed to the Leman gas field as this satisfied the CO_2 storage requirement of GEC with the proposed increase in permitted generation capacity and does not have any potential users.

4.56 Therefore, whilst the decision as to which specific storage site to use will not be made until eventual implementation of CCS, as shown in Table 4-4, using the updated information available regarding the preferred CO_2 storage area for GEC, the Proposed Development would require less than 2% of the remaining storage capacity of the Leman gas field over its 25 year post abatement lifetime.

4.57 In addition, there are a large number of storage sites which exist in the same region that are capable of meeting the CO_2 storage requirements of the Proposed Development. Table 4-5 shows that the potential storage sites in the region have a storage capacity of in excess of 2,563 Mt CO_2. The Proposed Development would require less than 1% of this storage capacity in the SNS Basin over its 25 year post abatement lifetime.

4.58 Another possibility in the future is that there will be an available "CO_2 Network" in the region such that CO_2 from the Proposed Development and other plants in the area would be delivered to a "central hub", such as the Thames hub previously proposed by E.ON. From this central hub, the captured CO_2 could be delivered to a number of storage sites. A discussion of the transport implications of this option is provided in Section 4.4.

[11] https://www.gov.uk/government/collections/energy-infrastructure-development-applications-carbon-capture-readiness-decisions

4.59 The storage assessment should be reviewed on an ongoing basis as part of the two yearly Status Reports, with a view to incorporating developments in the updated design for the carbon capture plant. Statera Energy Ltd will keep under review the various pre- and post-combustion options.

Table 4-5 Potential Capacity Utilised for Proposed Geological Storage Areas

Field Name	Capacity of Geographical Storage Area / 10^6 tonnes	Total Volume of CO_2 emitted by proposed development/ 10^6 tonnes	Remaining capacity of Geographical Storage Area / 10^6 tonnes	Total Volume of CO_2 emitted by proposed development/ 10^6 tonnes	% of capacity
Hewett (L Bunter + U Bunter) Gas Field	359	340	19	24	N/A
Leman Gas Field	1203	84	1119	24	2%
SNS Region Total	2563	424	2139	24	1%

CO_2 Transport

Overall Route

4.60 There are various options available for transporting CO_2 from point of capture to final geological storage, including on and off--shore transportation by pipeline, potentially use of rail or road tankers and off-shore transportation by pipeline or shipping. It is considered that onshore transportation by road or rail is not likely to be economically feasible due to the volume of CO_2 required to be transported and the expectation that of-shore storage is likely to be required.

4.61 It is proposed for the purposes of this CCR report that the CO_2 captured from the Proposed Development will be transported to the storage site via pipeline. Transport via road or rail is not considered to be feasible or realistic given the volumes of CO_2 being transported. It is considered that shipping may have a role for the Proposed Development given the predicted CO_2 annual tonnages requiring transportation to storage, given the flexible and intermittent nature of operation of the peaking plant and in the event that policy and market forces do not encourage suitable combined or centralised pipeline infrastructure to collect emissions from multiple sites or sources. This may have a beneficial effect on the economic viability of any carbon capture scheme. This has not been assessed further in this report as the use of a dedicated pipeline represents the most conservative economic assumption for the transport requirement.

4.62 The most likely option identified at present would be a pipeline leaving the north eastern edge of the site, heading south to the Thames and then along the Thames Estuary, before continuing on to the storage sites in the South North Sea Basin. This is the preferred potential route which is focused on in this CCR study. Land easements and permissions would also need to be obtained but any new CCS project would need separate consenting at that time, so those land agreements would be secured as part of the consenting process. It is recognised that a route to the south of the site has the potential to link into E.ON's previously proposed 'Thames Cluster' detailed in "Capturing Carbon, Tackling Climate Change: A Vision for the CCS Cluster in the South East" (2009). As shown in Figure 4.3 the 'Thames Cluster' was intended to be a network of CO_2 pipelines which will link together power stations around the Thames and Medway Estuaries to enable transport of dense phase CO_2 to storage sites in the SNS Basin. In line with the Guidance, it is not assumed in this CCR study that the transport of captured CO_2 will be able to be outsourced to a hub or cluster such as the Thames Cluster, since the project must be considered without reliance on schemes that may not happen.

4.63 It is understood that with the abandonment of the Kingsnorth CCS project (and the decommissioning and demolition of the power station) the proposals for this cluster have been withdrawn. However, if any updates are available in the future this option will be further reviewed as it could realise cost savings for CCS enabled projects in the region.

Figure 4-3 E.ONs proposed route of CO_2 pipeline from Thames Cluster

4.64 The off-shore pipeline would run east wards, before turning north to run parallel to the east coast before linking in with the Hewett or Leman storage sites, discussed in Section 4.3.

Predominantly Onshore Transport prior to transition

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

4.66 Developing networks where clusters of power stations or other heavy industry adopting CCS could use the same pipeline infrastructure would be much more practical and economic and minimise environmental impacts compared to each installation building its own separate pipeline.

Predominantly Offshore Transport

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

4.68 Navigation of wind farm sites and associated cabling, dredging areas, existing pipeline infrastructures and disposal sites via the proposed route would be feasible. Experience gained by the natural gas and oil industry in laying pipelines in the SNS Basin would provide the techniques and expertise required to accomplish this.

4.69 The routes of shipping lanes are not anticipated to be a significant barrier to this form of transport, because the pipeline would run along the seabed at a depth sufficient enough to allow ships to free passage. The impacts of the offshore CO_2 pipeline would be minimised by keeping the route of the pipeline a sufficient distance away from the shore so as not to impact any designated coastline. It is therefore considered that a feasible route exists to remove the captured CO_2 from the proposed development to either of the storage sites identified.

5. Economic Assessment

Retrofit

5.1 The principal economic driver currently available for CCS viability, without Government fiscal support, is the price of carbon. The price of carbon needs to have achieved a high enough monetary value to make carbon capture and storage economically viable. The carbon market remains very volatile; however, regulation and financial incentives are two other options to assist with the development of carbon capture technology after the initial demonstration phase. While the current Emissions Performance Standard (EPS) is set at a level that does not require the use of CCS on efficient new build gas-fired power stations (450 g/kWh at baseload), this may change in the future as both the EU and the UK Government continue to aspire to decarbonise electricity generation. These issues are however beyond the control or scope of the Proposed Development.

5.2 The Applicant therefore proposes to draw on existing economic modelling developed over a number of sites. Such modelling provides indications of the likely range of costs associated with the introduction of CCS facilities. These models include fuel price; carbon price; capture costs; transport costs and storage costs. Models have also looked at Enhanced Oil Recovery projections; network supported projections and variations around re-use of existing assets or construction of new assets. There is also the probability that costs will diminish as implementation moves from demonstration to roll out of installed capacity. The 2011 "CCS Strategy and Action Plan for the Greater South East' prepared by Camco for the South East England Development Agency (pg.28) suggested a cost for CO_2 capture of £35/tCO_2 (mid-range, CCGT).

5.3 The above capture cost estimate has also been reviewed by considering capture costs as described in the BEIS Electricity Generation Cost Report information published Nov 2016. The BEIS report, largely agrees with the above estimate for capture costs for a 'standard' CCGT. However, for current CCGT technology, the increased efficiency is reflected in reduced specific CO_2 emissions (c.330 kg/MWh). Using the figures for the H-class technology, as presented in the BEIS report, the levelised costs for retrofit carbon capture equipment for the Proposed Development is estimated at an increased £41/tCO_2 (average), with a range between £30 to £58/tCO_2:

- Capture = £41/t CO_2
- Onshore Transport = £4/t CO_2
- Offshore Transport = £6/t CO_2
- Offshore Storage in Oil and Gas Fields = £12/t CO_2
- Total: £63/t CO_2

5.4 Note that Case 1 in the BEIS report (projects commissioning in 2020) does not include CCS, whereas Case 2 (projects commissioning in 2025) and Case 3 (projects commissioning in 2016,18,20,25,30) show a range of CCS cost assumptions.

5.5 The BEIS Electricity Generation Cost Report predicts the levelised cost on a through life/MWh basis rather than a capital cost / kW basis and presents data for CCGT and OCGT with and without CCS, but does not give an indication of the likely costs for reciprocating gas engines. High/Low range values for plant commissioning in 2025 show:

- CCGT levelised costs without carbon capture will be in the range of £80 – £83 per MWh;
- With CCS, costs for CCGT will be in the range of £90 – £128 per MWh;
- With CCS, costs for OCGT will be in the range of £156 – £181 per MWh

5.6 Within the scope of this CCR study, it is noted that the publicly available data has been developed on the basis of CCGT plant operating at baseload in order to determine full chain lifetime costs amortised over the total lifetime tonnage of CO_2 captured, transported and stored.

5.7 In the case of reciprocating peaking plant of the type envisaged for the proposed development, a capacity factor of 40% has been used, based on 3,500 hours per year operation. This would more than double the lifetime CCS costs per tonne of CO_2. Assuming that the CAPEX element is approximately 40% of these costs, a less conservative figure would potentially double the lifetime costs per tonne.

5.8 As noted in the case of gas reciprocating plant (Technology section 4.2.12), the lack of inherent steam raising and the reduced exhaust temperature compared to CCGT plant increases the need for additional equipment and for supplementary firing. This will lead to increases in capital and operating costs along with increased fuel inputs.

5.9 Nonetheless, recent studies e.g. by Imperial College (Valuing Flexibility in CCS Power Plants) indicate there is the potential for so-called flexible CCS to deliver improved Total System Value compared to conventional CCS plant, which supports that there is an economic solution to be found.

5.10 In summary, deployment of CCS will add significant cost to both the capital outlay and the operation of any power station, however, subject to market conditions (based on high level assumptions) the Proposed Development can in principle achieve an economically viable carbon capture solution if required in the future, as the site:

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

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

5.12 The assessment therefore suggests that there should be no known economic barriers to capture, transport and storage of emissions of CO_2 from the Proposed Development subject to an appropriate industrial strategy, the future costs of carbon and that Carbon Capture and Storage (CCS) technology could be retrofitted at a later date,

5.13 The provision of highly flexible power generation is considered essential for the UK electricity grid as the transition to full decarbonisation and Net Zero continues, in particular to balance the intermittency of renewable generation. The service that a flexible gas-fired reciprocating generator provides and its viability is predicated on higher margins and fewer hours of operation. This proposed development is anticipated to operate up to 3500 hours per year, with current CCGT operating hours within the UK of the order of 4,000 hours per year or higher, and with the higher merit units operating around 6,000 hrs per year. CCGTs – even flexibly operated ones – cannot achieve the same level of flexibility to meet near instantaneous grid demands as open cycle or reciprocating engine peaking plant.

5.14 The role of the CCGT and the peaking plant is therefore different in supporting the UK electricity grid and direct comparison of Carbon Capture economics between the two technologies is not considered appropriate. In particular, the current UK market does not support the capital cost of developing new CCGT since predicted load factors do not provide adequate return on investment. Therefore new high efficiency CCGTs cannot currently be deployed.

5.15 Inevitably meeting the steam demand of the CCS plant combined with the lower efficiencies associated with peaking plant (OCGT or reciprocating engines) mean that the cost of CCS per MW of electricity generated or per tonne of CO_2 abated is higher for the flexible plant than for a CCGT. However, the cost of CCS for reciprocating engines of the type proposed in this development is lower than that for an OCGT of comparable output as the engines are more efficient. Therefore, should CCS be mandated to be installed on peaking plant providing that essential support to the national grid, the cost of installation on high efficiency reciprocating engines – while higher than that for a CCGT performing a different function – is lower than that of potentially comparable peaking plant technologies.

5.16 It is considered that additional feasibility work is required to demonstrate the effectiveness of operating CCS technology on intermittent plant given the expected future demand for such plant to support the increased penetration of renewables onto the UK electricity grid. A number of alternative innovation technologies are being developed to enhance the feasibility of deploying CCS on flexible plant including use of molten carbonate fuel cells.

6. Health and Safety

Pipeline

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

6.2 Current UK experience of designing and operating CO_2 pipelines is limited and only some pipeline design codes include it as a relevant fluid within their scope. European Standards implemented in the UK as British Normative Standards (BS EN series) and supported by published documents (such as the British Standards PD series) provide a sound basis for the design of pipelines.

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

6.4 The '*Comparison of risks from carbon dioxide and natural gas pipelines*' (Health and Safety Executive, 2009) concluded that a loss of containment event from a dense or supercritical phase CO_2 pipeline presents a similar level of risk to a release from a high-pressure natural gas pipeline. As such, designers of CO_2 pipelines should consider applying a similar fluid hazard categorisation (chosen from an established pipeline design code) to that applied to high pressure natural gas pipelines.

6.5 The pipeline would therefore be considered to be a Major Accident Hazard Pipeline (MAHP).

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

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

6.7 In addition, the Local Authority, which would be notified by the HSE of a MAHP, must prepare an Emergency Plan.

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

On-Site

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

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

7. CCR Review

7.1 The Applicant is committed to review and report on the effective maintenance of the CCR status for the Proposed Development, within three months of the commencement of commercial operations, and at least every two years thereafter. Statera Energy Ltd will keep under review the various pre- and post-combustion options.

Appendix A Carbon Capture Strategy Report

AECOM Imagine it. Delivered.

Thurrock Flexible Generation Plant

Carbon Capture Readiness Study - Compliance Strategy

Thurrock Power Ltd

Project reference: PR-335780
Project number: 60592577
60592577-401-000-ME-RP-00001

07 November 2018

Quality information

Prepared by	Checked by	Verified by	Approved by
19/11/18	26/11/18	26/11/18	30/11/18
Graeme Cook Process Team Lead	Klim MacKenzie	Richard Lowe	David Hope

Revision History

Revision	Revision date	Details	Authorized	Name	Position

Distribution List

# Hard Copies	PDF Required	Association / Company Name

Prepared for:

Thurrock Power Ltd
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Table of Contents

Figures

Tables

1. Introduction

A new generating station with output capacity of up to a nominal 600MWe is proposed by Statera Energy Ltd. The plant is to supply power on a 2000-3000 hour per year basis, consisting of a bank of natural gas-fired reciprocating internal combustion engines. The intention is to build the plant out to an initial capacity below 299MWe followed by a further development beyond 299MWe which triggers CCR consideration for the full 600MWe. The site is to operate on an open cycle basis. No CHP requirement is considered as part of this study.

The purpose of this study is to investigate the Carbon Capture Readiness (CCR) of the gas fired reciprocating internal combustion engines at the proposed 600MWe peaking plant in Tilbury, Essex.

Based upon earlier studies and as confirmed by the Client the cooling system will be via air cooled radiators using a closed loop recirculating system.

This document outlines the key assumptions proposed to be used for the CCR report and to determine that appropriate space has been allocated within the DCO Works Plan for the future retrofit of carbon capture equipment, should it be required. This report is for discussion with the Client and Imperial College as the independent verifier.

2. Abbreviations

Table 1. Abbreviations

Abbreviation	Definition
kW	Kilowatt
MWe	megawatt of electrical power
MWth	megawatt thermal power
BAT	Best Available Technology
CCR	Carbon Capture and Storage
CHP	Combined Heating and Power
HT	High Temperature
LT	Low Temperature
O&M	Operations and Maintenance

3. Site data

3.1 Temperature

Maximum air temperature:	22°C	Ti bury Monthly Climate Averages, World Weather Online, Retrieved 16 August 2018, https://www.worldweatheronline.com/tilbury-weather-averages/essex/gb.aspx

3.2 Power Plant

The site is to be powered by an array of reciprocating gas-fired internal combustion engines. Earlier studies assumed the use of the Rolls Royce B36:45V20AG engine.

Current assumptions are around the selection of 48 x 12.5MWe MAN 20V35/44GTS engines, or 32 x 18.4MWe MAN 18V51/60GTS engines. The baseline configuration is to install SCR to reduce NOx emissions to 20mg/Nm3.

The assumed operating profile is to ramp rapidly to full load on the following typical basis:-

Summer	2 shift	2-3 hours per shift am and pm
Winter	2 shift	6 hours per shift am and pm with ~ 2 hrs rest period between

Thermoflow models are not available for these engines and so a user defined engine will be used.

MAN data sheet has been prepared at 10 degrees C.

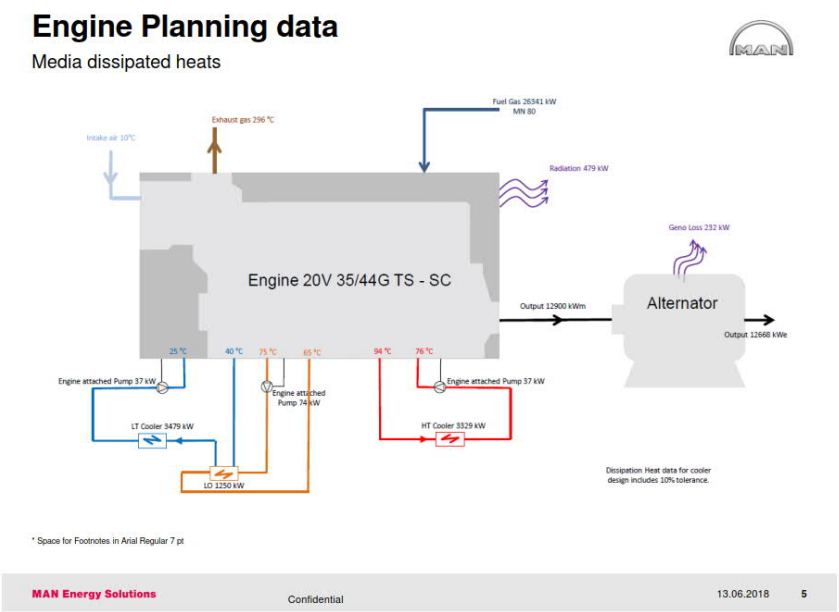

Figure 1. MAN Engine Data

4. CCR Compliance Strategy

4.1 Carbon Capture Technology and Operation

EU and UK Legislation requires gas fuelled generation plant of capacity in excess of 300MWe to demonstrate the ability to retrofit carbon capture equipment at a future time. This has generally involved the use of the 2009 DECC Carbon Capture Readiness guidance [A guidance note for Section 36 Electricity Act 1989 consent applications], as amended by Imperial College studies, to establish whether sufficient area is available based upon a number of reference studies for combined cycle generation plant using pre-combustion, post-combustion and oxy-combustion options. These plant areas have commonly been normalised based upon pre-abatement plant export capacity to provide a specific area. Where concept design layouts have been developed it has been acceptable to use lower values of this specific plant area to a minimum specific area requirement of 37.5m^2/MW for post combustion capture of a CCGT.

In the case of gas fire reciprocating plant, no such benchmark exists and so AECOM propose to carry out preliminary plant design using Thermoflow software.

For the purposes of this CCR study it is recognised that the operation of flexible and intermittent peaking plant and conventional acid gas [amine] carbon dioxide absorption plant have different requirements in terms of ramp up times, efficacy during intermittent operation and emissions profiles. It is likely that a combination of CCS bypass and Amine plant on a warm stand-by will be required; however these will be identified as challenges and potential constraints for future studies as the concepts of flexible CCS develop.

This CCR study will focus on developing a concept design for the plant and the technical challenges of provisioning an adequate space envelope to allow future installation.

4.2 Comparison with CCGT configuration

A number of recent projects under consideration have proposed the use of H class CCGT technology with output capacities of the order of 830-860 MWe per train. This duty comprises:

- Gas turbine providing 580-610 MWe, approximately 70% of the total output
- Steam turbine providing remaining 250-350 MWe, approximately 30% of the total output

As shown in Table 2, the carbon intensity (defined as the quantity of carbon dioxide emitted per net kilowatt of electricity exported) is comparable between a single gas turbine (e.g. GE 9HA) and the proposed 600 MWe reciprocating engine development. It is therefore expected that the total area required for carbon capture equipment at the 600MWe Thurrock Flexible Generation plant will be similar to that of a single train of an H Class CCGT such as proposed in a number of recent studies including for example the public domain report on the Eggborough assessment.

Table 2. Comparison of carbon emissions from 600MWe gas turbine and 600MWe of reciprocating engines

Model	Gross Power (MWe)	Net LHV Efficiency (%)	Carbon emissions (kg/s)	Carbon intensity (kg/MWhe)
GE 9HA02(1 off)	554	43.9	69.2	449
MAN 20V35/44 (48 off)	619	49.0	70.8	412

No benchmark figures are currently available specifically for carbon capture area requirements for reciprocating engine facilities from DECC / BEIS. AECOM has therefore made an initial estimate by pro-rating the area value from a scaled electricity export rate i.e. dividing the area by a factor of 0.7 to account for the loss of the steam turbine. The two area requirement values (dependant on level of analysis) have been calculated as 68.6m^2/MWe or 53.6m^2/MWe for an open cycle reciprocating plant. In comparison, the equivalent CCGT reference values are 48m^2/MWe and 37.5m^2/MWe which include additional electricity export from the steam turbine. The larger of the two figures is based directly on the DECC guidance, and the lower figure has been accepted by Imperial College as independent verifier where preliminary plant design has been carried out.

Initial space allocation at Thurrock Flexible Generation is of the order of 35,000 m^2 or 58 m^2/MWe although accommodating a natural gas compound leaves 32,500 m^2 or 54 m^2/MW, validating the need for preliminary process modelling and a concept design to be developed to justify this area as being sufficient. Note that the potential CCS equipment areas have over-sailing overhead lines and this constraint should be recognised in the evaluation of available area. Reference in the CCR report may be acceptable without necessarily curtailing the available area.

There are also a number of significant differences between the basic power generation plant configurations of the CGT and reciprocating gas engine technologies, aside from the operational differences between baseload and peaking duties. Since the gas fired reciprocating plant is open cycle and no CHP is planned, there is no ready source of steam for the amine reboiler in the carbon capture baseline plant. Studies carried out on H class CCGT plants for recent UK projects have determined a steam load of the order of 225 MWth for this size of CCS plant required, which would be raised using LP or IP steam, typically on a CCGT derived from the IP/ LP crossover. The equivalent interface temperatures are shown below:

Condition	1 H class turbine	48 x 12.5 MWe gas engine
Exhaust mass flow kg/s	~1100	947
Turbine / Engine Exit temperature C	645	296
HRSG Outlet temperature C	75	~150 C from proposed additional fired duct boiler

The flue gas temperature entering the initial cooling stage of the carbon capture plant has been set to 75°C in order to maintain a comparable design with the CCGT flue gas cooler. Based on an engine exhaust temperature of 296°C, the maximum available heat from the reciprocating engine plant is given by:

$$Q = m \times C_p \times \Delta T = 947\frac{kg}{s} \times 1.1\frac{kJ}{kg.K} \times (296°C - 75°C) = 230\ MW_{th}$$

The amine regenerator would require ~225 MWth of heat which is greater than that available from the exhaust gas. Therefore, supplementary duct firing is required to raise the full steam flow required by the amine regeneration process.

Preliminary sizing of a suitable fired duct boiler to provide the necessary supplementary heat results in a higher exhaust outlet temperature of ~ 150C, increasing the duty in the CCS plant by:

$$946\frac{kg}{s} \times 1.1\frac{kJ}{kg.K} \times (150°C - 75°C) = 78\ MW_{th}$$

5. Proposed Approach to CCR Report

AECOM propose that the CCS assessment be made with the following assumptions:

1. CCR capture plant area will be based upon CCGT post-combustion capture models developed for H class technology with due consideration for the gas turbine derived emissions and power generation

2. Specific area consideration will take in to account the percentage of power generated without consideration of the steam cycle in conventional CCGT plant by derating the threshold values for a CCGT plant by a factor of 0.7 to determine the required area for an open cycle reciprocating engine plant.

3. The impact of adding steam generation equipment and increased cooling duty due to the higher exhaust interface temperatures will be accounted for in the modelling of the CCS plant interfacing with a reciprocating gas fired engine.

4. Allowance will be made in the specific area criterion to account for the multiple reciprocating engine layout and the developing experience base on gas reciprocating engine feasibility studies. The

specific area minimum requirement is proposed to be between 53.6m^2/MWe and 68.6m^2/MWe based on the calculations presented above.

5. Carbon capture modelling will be carried out on an ambient temperature of 15°C. It is noted that the OEM engine model has been provided at 10 C which is considered optimistic. A reference case for the engine running at 15°C shall be requested from the OEM .The use of fin-fan cooling as the reference case offers some margin on area requirement however in order to include some conservatism the effect of higher ambient temperatures will be considered to account for the level of monthly average site temperatures

6. Operational issues related to the implementation of flexible CCS cycles will need to be addressed as the market develops and this is considered to present an economic rather than a technical challenge to future deployment of CCS. The future technical solution may be based upon an assumption that the gas engines can be run in bypass with the amine plant operating under warm standby conditions with acid gas introduced to the CCS plant in such a way as to minimise the risk of tower foaming or flooding. However it is recognised that use of warm standby increases the rate of amine loss and degradation and therefore increases operating costs for any such CCS plant.

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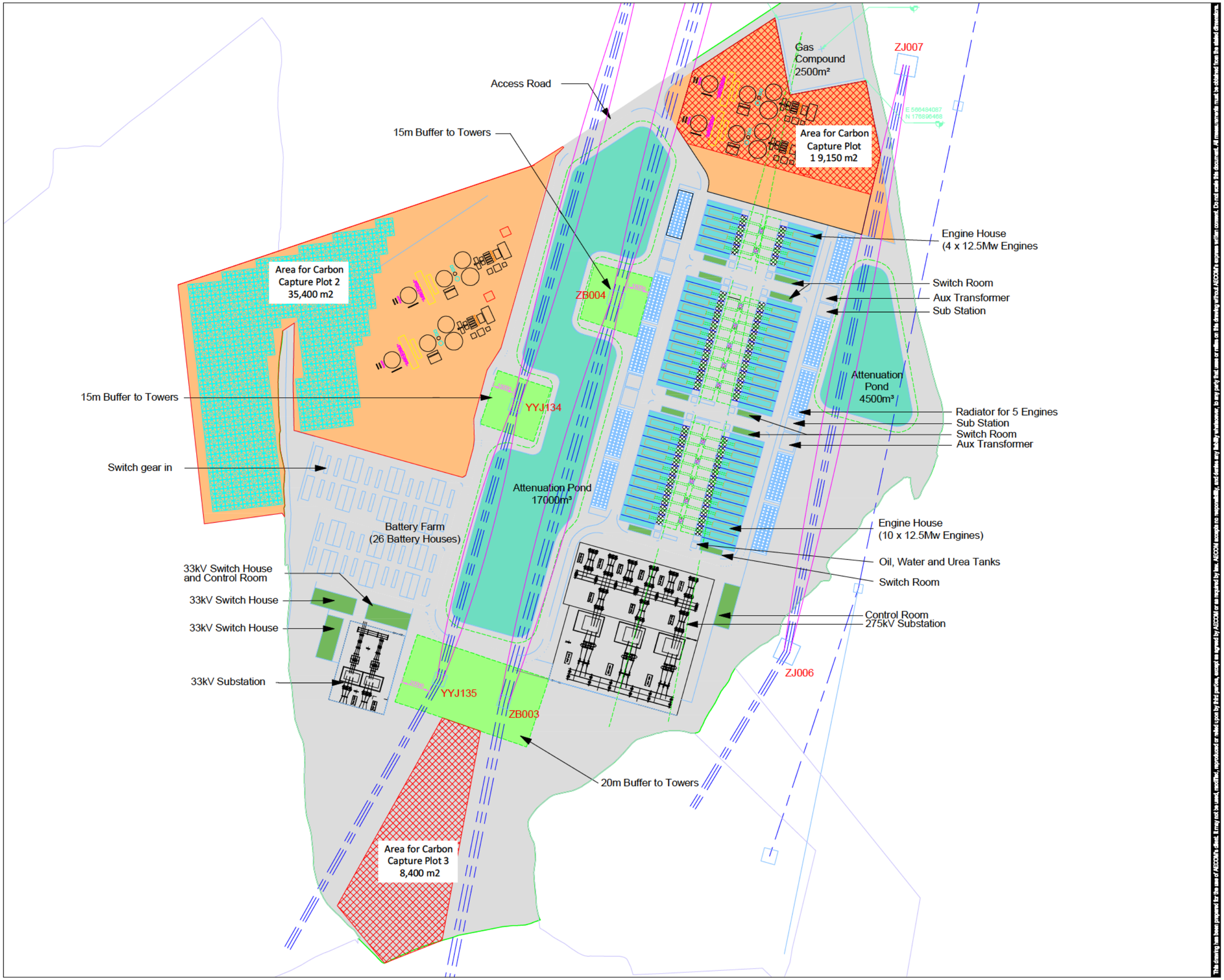
Appendix B CCR Layout



AECOM

PROJECT

THURROCK FLEXIBLE GENERATION PLANT

CLIENT

STATERA ENERGY

CONSULTANT

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GENERAL NOTES

ISSUE/REVISION

I/R	DATE	DESCRIPTION

KEY PLAN

PROJECT NUMBER

60592577

SHEET TITLE

INDICATIVE CARBON CAPTURE EQUIPMENT LAYOUT

SHEET NUMBER

60592577-ACM-STA-00-00-LAY-P-006

Project Management Initials: Designer: des Checked: chk Approved: app ISO A1 594mm x 841mm
Last saved by: KENNEDYK(2020-02-03) Last Plotted: 2020-02-03
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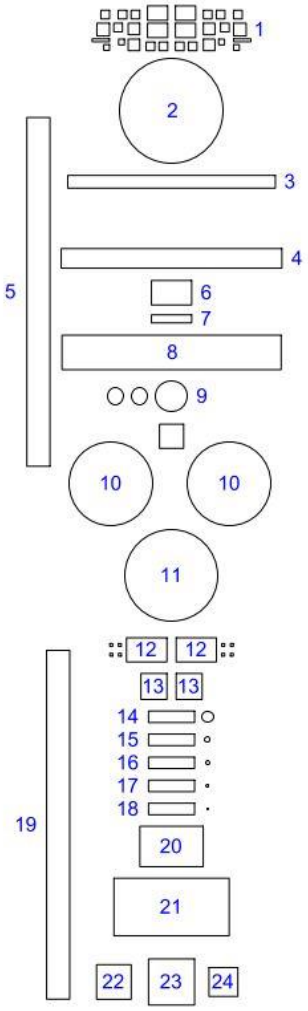
Appendix C Equipment Layout



1. PUMPS
2. DCC COLUMN
3. WASH WATER COOLER
4. LEAN AMINE COOLER
5. SOLVENT CROSS EXCHANGER
6. RECLAIMER
7. STRIPPER CONDENSER
8. STRIPPER REBOILER
9. AMINE STORAGE TANK
10. ABSORBER
11. STRIPPER
12. LEAN SOLVENT FILTER
13. ACTIVATED CARBON FILTER
14. COMPRESSOR STAGE 1 INTERCOOLER & DRUM
15. COMPRESSOR STAGE 2 INTERCOOLER & DRUM
16. COMPRESSOR STAGE 3 INTERCOOLER & DRUM
17. COMPRESSOR STAGE 4 INTERCOOLER & DRUM
18. COMPRESSOR STAGE 5 INTERCOOLER & DRUM
19. PLACE HOLDER FOR STEAM BOILER
20. CO2 COMPRESSION UNIT
21. CO2 DEHYDRATION UNIT
22. ANTIFOAM SYSTEM
23. INSTRUMENT AIR SYSTEM
24. NITROGEN BLANKETING SYSTEM

Appendix D Technical Memo to Imperial College

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Project name:
Fired Reciprocating Engine CCR Study

Project ref:
60592577

From:
Graeme Cook

Date:
03 Apr 2019

To:
Dr Paul Fennel
IC Consultants Limited,
58 Prince's Gate,
Exhibition Road,
London,
SW7 2QA

CC:
David Hope
Richard Lowe
K MacKenzie

Memo – Duct Firing of Gas Reciprocating Engine Flexible Generation Plant

Reference: -

1/ email Duct Firing from P Fennel to G Cook, sent 01 Mar 2019

2/ email Thurrock Flexible Generation from G Cook to P Fennell, sent 07 Mar 2019

Discussion:-

In order to formally record the technical basis of discussions between IC Consultants and AECOM regarding duct firing to raise process steam for carbon capture, the email response is recorded below.

Technical Basis:

AECOM does not have access to the specific MAN generator unit in Thermoflow and so have developed a custom model of the MAN engine based on datasheets the client sent us, from the ground up based on the engine specs, with some qualifying assumptions suitable for the level of detail of this study.

We have not gone to the detail of duct burner design beyond considering the overall requirements on a whole site and per unit basis. We expect that there is an optimum size for the duct burner and for the purposes of this preliminary study we have converged on 4 trains in total with a bank of 48/4 = 12 engines per train.

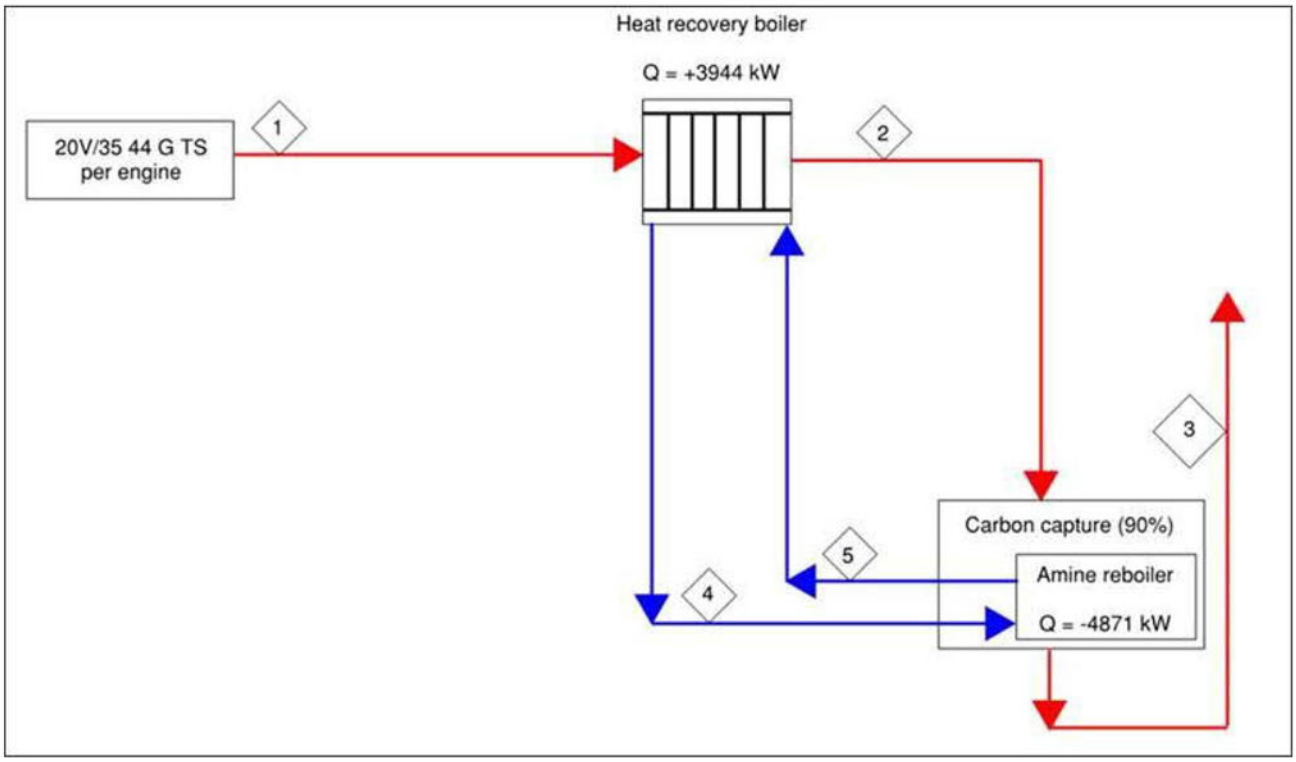
We are updating the plant layout to show legend and bubble numbers for the main plant items. In table 4.1

We have been advised that the engines are likely to be operated between 2000-3000 hrs per year.

Base case, per submitted report

The engine models currently being considered by the client are MAN 20V35/44GTS, rated at 12.5MWe net. The material balance for the exhaust stream is shown in the figure below. System design basis:

- Typical MEA unit capture
- 90% capture of CO_2 by mass



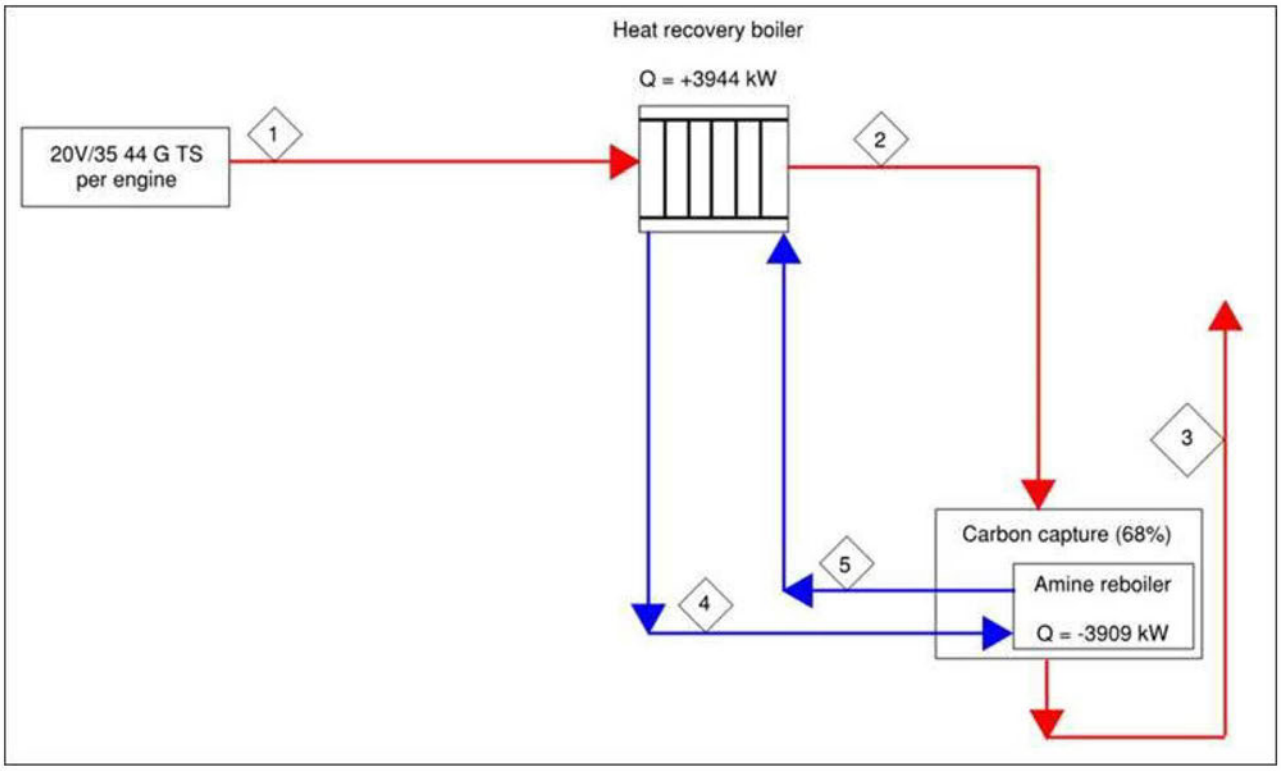
Case:	Base case				
Stream no.	1	2	3	4	5
Description	Engine exhaust to boiler	Exhaust gas from boiler to CCS	Residual exhaust gas to stack	Steam supply to CCS reboiler	Steam condensate from CCS reboiler
Temperature (°C)	296	115	37	140	111
Mass flow total (kg/s)	19.97	19.97	18.06	2.24	2.24
CO_2 by mass (wt%)	7.43	7.43	0.82	-	-
Specific enthalpy (kJ/kg)	293.47	95.97	12.66	2739.4	561.5

The engine exhaust stream (Stream 1, 19.97kg/s), carries approximately 7.43 mass% CO_2. A typical DEA system has been estimated to require approximately 4871 kW duty in the regenerator reboiler for a 90% (by mass) absorption.

In contrast, a balance of heat recovery from the exhaust flue gas shows only 3944 kW is available (between streams 1 and 2), further recovery would not be practical as the temperature of the gas outlet (Stream 2, 115°C) approaches that of the condensate supply (Stream 5, 111°C).

Maximum capture within available heat envelope

A comparison case was run with carbon capture reduced to 68% of inlet mass flow. Reboiler duty in this case was found to be 3909 kW (see figure below). It is expected that the available duty from the flue gas (3944 kW) could provide a maximum of 68wt% capture.

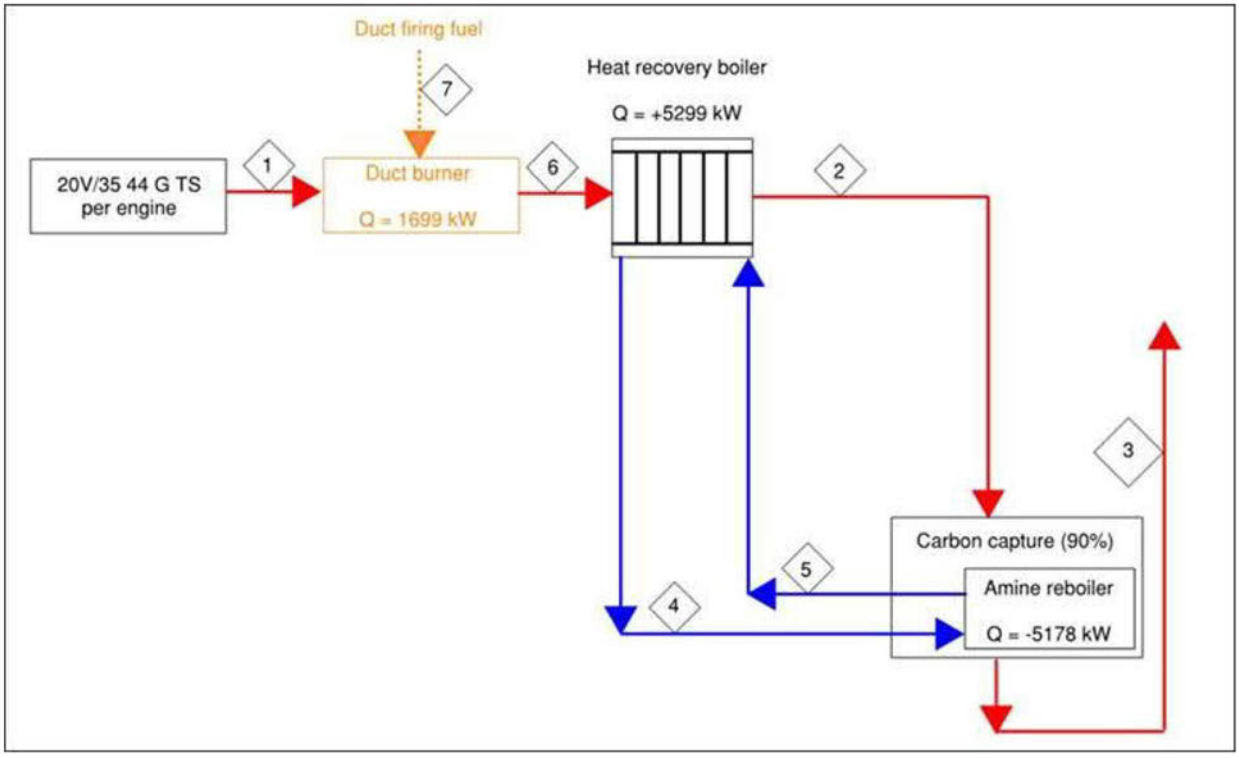


Case:	Max capture within flue gas limit (68% capture)				
Stream no.	1	2	3	4	5
Description	Engine exhaust to boiler	Exhaust gas from boiler to CCS	Residual exhaust gas to stack	Steam supply to CCS reboiler	Steam condensate from CCS reboiler
Temperature (°C)	296	115	37	140	111
Mass flow total (kg/s)	19.97	19.97	18.25	2.37	2.37
CO_2 by mass (wt%)	7.43	7.43	2.8	-	-
Specific enthalpy (kJ/kg)	293.47	95.97	12.62	2739.4	561.5

90% carbon capture with duct firing

An in-line duct burner was proposed to maintain 90% carbon capture (by weight) from the engine exhaust stream. The use of a duct burner on the exhaust from a reciprocating engine is not considered to be analogous to the use of a standalone boiler on a CCGT power plant. The gas turbine on a CCGT power plant has, by definition, excess heat which is used by the steam cycle. Sufficient heat is normally available from the steam cycle and additional dedicated heat is not necessary (from a thermodynamic point of view) to facilitate the carbon capture plant. External boilers would cause their own emissions, the treatment of which is not necessarily clear with a potential for unabated emissions from any standalone boilers. A duct burner on a reciprocating engine exhaust is, by definition, in-line with the exhaust flow, adding sufficient enthalpy to drive the treatment for the combined (engine + burner) flue gas. In the case of this reciprocating

engine plant, the exhaust stream is produced at approximately 296°C and sufficient enthalpy is not available between the temperature of the exhaust and the minimum temperature difference with the amine regenerator (operating at approximately 120-130°C). Refer to the diagrams below:



Case:	Duct firing to achieve 90% capture						
Stream no.	1	2	3	4	5	6	7
Description	Engine exhaust to duct burner	Exhaust gas from boiler to CCS	Residual exhaust gas to stack	Steam supply to CCS reboiler	Steam condensate from CCS reboiler	Exhaust from duct burner	Fuel gas to duct burner
Temperature (°C)	296	115	37	140	111	370	25
Mass flow total (kg/s)	19.97	20.01	17.93	2.38	2.38	20.01	0.034
CO_2 by mass (wt%)	7.43	7.89	0.88	-	-	7.89	-
Specific enthalpy (kJ/kg)	293.47	96.26	12.62	2739.4	561.5	377.8	50046
LHV kJ/kg	-	-	-	-	-	-	50046

In order to maintain 90% carbon capture (chosen as a baseline comparable with CCR basis on other plants), supplementary heat is thermodynamically required for the carbon capture plant (4871 kW per engine available in base case) as the exhaust gas from the reciprocating engines does not carry sufficient heat for carbon capture (3944 kW available per engine). Instead, it was proposed that a duct boiler be added, increasing the carbon capture requirement to 5178 kW while simultaneously increasing available duty to 5299 kW. The duct burner is considered more analogous to an electric heater than a standalone boiler as the incremental increase in emissions is also processed in the carbon capture plant.

It is acknowledged that there would be an incremental increase in carbon dioxide emissions in the duct burner case, total CO_2 flows are calculated as 1.58kg/s and 1.48kg/s for Streams 6 and 1, respectively. The increment is calculated as 0.1kg/s CO_2 and leads to a net increase of 0.01 kg/s when comparing Stream 3 for the base case against duct firing (0.148kg/s and 0.158kg/s, respectively). The increment is deemed small and if duct firing is acceptable, the net carbon capture recovery could be increased to maintain net CO_2 emissions with the base case.

If duct firing is unacceptable, it is expected that the limit of carbon capture recovery would be approximately 68% by weight.

Plant efficiency with duct firing

The impact of duct firing on plant efficiency was calculated:

	Base case recip, 48 off	Duct firing recip, 48 off
Net electricity exported, less losses for 90% capture (MW)	514	514
Net heat input (MW)	1264	1346
Net calculated efficiency (%)	40.6	38.2
Net CO_2 emissions before capture, kg/s	70.8	75.3
Net CO_2 emissions to atm post-capture, kg/s	7.1	7.6

The efficiency penalty for duct firing was calculated as 2.4 absolute percentage points. Note this is net of approximately 2.2MW of auxiliaries per engine for the carbon capture equipment.

Conclusions

The data presented above has been used by IC Consultants to inform their review of the AECOM Fired Reciprocating Engine CCR Study

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