Gateway Energy Centre

ENVIRONMENTAL STATEMENT

CCR Feasibility Study

Prepared by

PARSONS BRINCKERHOFF

February 2010

CONTENTS

LIST OF ABBREVIATIONS

°C	Degrees Celsius
ACC	Air Cooled Condenser
CCGT	Combined Cycle Gas Turbine
CCR	Carbon Capture Readiness
CCS	Carbon Capture and Storage
CECL	Coryton Energy Company Limited
CHP	Combined Heat and Power
CHR	Cold Re-Heat
CO_2	Carbon Dioxide
COMAH	Control of Major Accident Hazards
DECC	Department of Energy and Climate Change
DTI	Department of Trade and Industry
EIA	Environmental Impact Assessment
EISB	East Irish Sea Basin
ES	Environmental Statement
EU	European Union
EU ETS	EU Emissions Trading Scheme
GEC	Gateway Energy Centre
GECL	Gateway Energy Centre Limited
GJ	Gigajoule
ha	hectares
HRSG	Heat Recovery Steam Generator
HSC	Hazardous Substances Consent
HSE	Health and Safety Executive
HSS	Heat Stable Salts
kg/s	Kilograms per second
km	Kilometres
IP	Intermediate Pressure
LCPD	Large Combustion Plant Directive
LG	London Gateway
LHV	Lower Heating Value
LP	Low Pressure
m	Metres
MAHP	Major Accident Hazard Pipeline
MEA	Monoethanolamine
Mt	Megatonnes
MWe	Megawatts Electric
NO_2	Nitrogen Dioxide
O_2	Oxygen
OS	Ordnance Survey
PB	Parsons Brinckerhoff Limited
PM	Particulate Matter
ppm	Parts per Million
PSR	Pipeline Safety Regulations
SCR	Selective Catalytic Reduction
SNS	Southern North Sea
SO_2	Sulphur Dioxide
SO_x	Sulphur Oxides
t/h	Tonnes per hour
UK	United Kingdom

SECTION 1

INTRODUCTION

1 INTRODUCTION

1.1 Overview

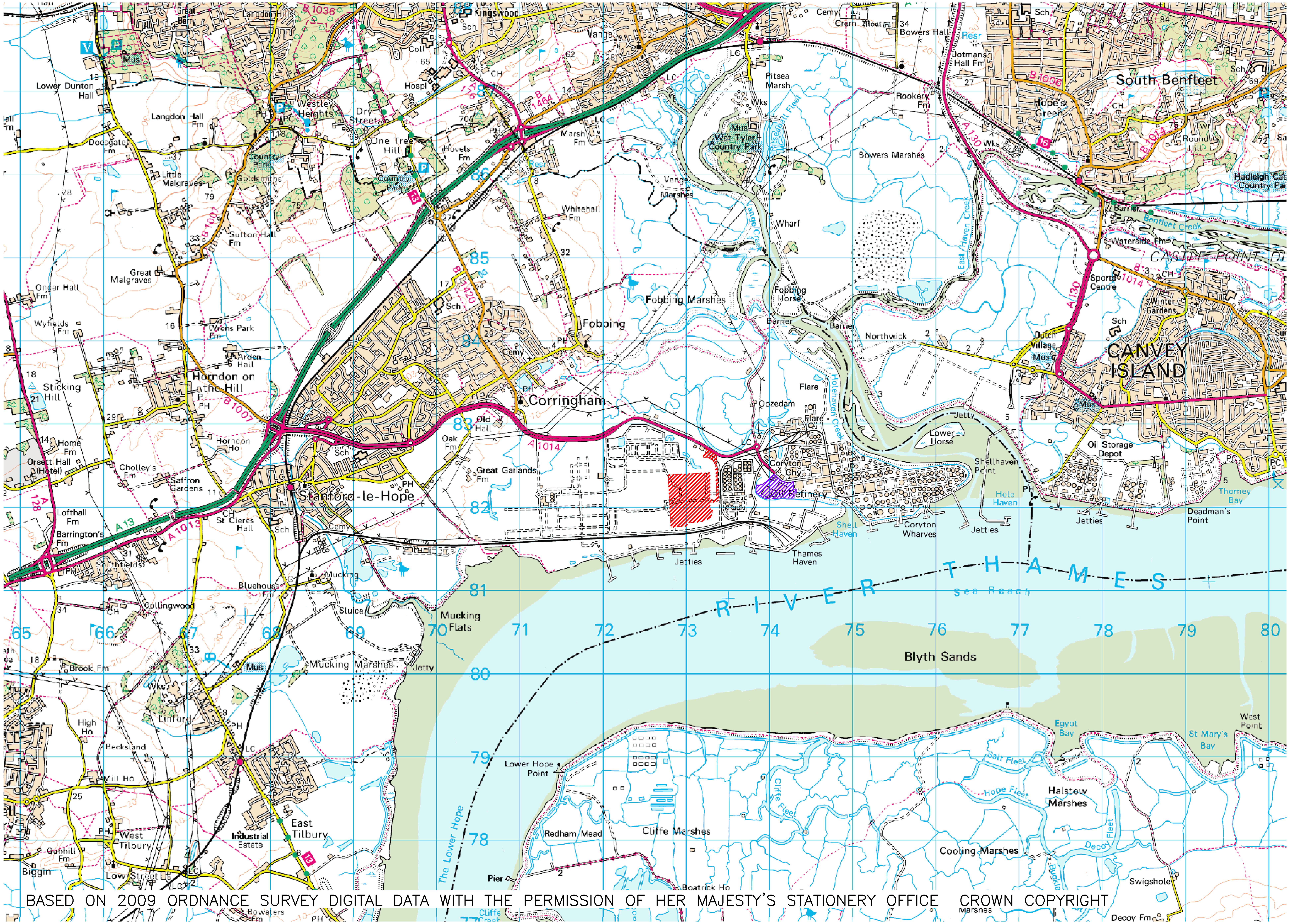
1.1.1 This Carbon Capture Readiness (CCR) Feasibility Study has been undertaken by Parsons Brinckerhoff Limited (PB) on behalf of Gateway Energy Centre Limited (GECL) to support a Consent application for the proposed Gateway Energy Centre Combined Cycle Gas Turbine (CCGT) Power Plant to be known as Gateway Energy Centre or GEC.

1.1.2 The Consent application for GEC will comprise an application under Section 36 of the Electricity Act 1989 to the Department of Energy and Climate Change (DECC) to construct and operate a power station of greater than 50 MWe together with deemed planning permission under Section 90 of the Town and Country Planning Act 1990.

1.1.3 GEC will be located on land within the London Gateway Port / London Gateway Logistics and Business Park development, collectively called LG Development. The site location is shown in Figure 1. The LG Development, promoted by DP World, is currently in the early stages of construction.

1.1.4 GEC will provide up to 900 megawatts electric (MWe) of electrical generation capacity. This will include the provision of up to 150 MWe to the LG Development, which is expected to meet its long-term requirements. Additionally, there is also the possibility for GEC to supply heat in the form of steam or hot water to facilities and / or customers in the vicinity of the site.

1.1.5 The configuration of GEC will likely comprise two combined cycle gas turbine units, fuelled by natural gas. Each unit will comprise a gas turbine and a heat recovery steam generator (HRSG) which will provide steam to the steam turbine equipment.



LEGEND

GEC APPLICATION SITE LOCATION

CECL POWER STATION LOCATION

0 1000m 2000m 3000m

BAR SCALE 1:50,000

REV	DATE	DESCRIPTION	BY	CHKD	APPD

• NOTES

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• CLIENT/PROJECT
GATEWAY ENERGY CENTRE

• TITLE
GEC APPLICATION SITE LOCATION

• DATE 13/10/09
• SCALE 1/50000
• CAD REF

DRAWN BY	DD
PRODUCED BY	DD
CHECKED	EA
APPROVED	EA

• DRAWING NUMBER
FIGURE 1 | –

THIS DRAWING WAS PRODUCED USING AUTOCAD AND SHOULD ON NO ACCOUNT BE AMENDED BY HAND

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1.2 The Purpose of this Document

UK Government Policy

1.2.1 The European Union (EU) agreed the text of a new EU 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 Carbon Capture and Storage (CCS) Directive) in the Official Journal of the European Union on 5 June 2009 and the Directive came into force on 25 June 2009.

1.2.2 The CCS 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 MWe or more (and for which the construction / operating license was granted after the date of the Directive) will carry out a CCR Feasibility Study to assess whether:

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

1.2.3 In the UK the relevant competent authority in respect of energy matters is the DECC. DECC must ensure the CCS Directive is implemented. It is also free to impose more stringent regulations on power plants within the UK.

1.2.4 In June 2008, the UK Government published a consultation document "Towards Carbon Capture and Storage" to seek views on the steps it could take to prepare for and support both the development and deployment of CCS technologies.

1.2.5 A response to this consultation was published in April 2009, alongside draft Guidance for applicants seeking consent for new combustion power stations at or over 300 MWe[*] (the draft Guidance). The draft Guidance aimed to reflect the Government's new CCR Policy, and was subject to an eight week consultation period which ended on 22 June 2009.

1.2.6 The responses from the consultation period were incorporated into final Guidance published in November 2009 for applicants seeking Consent for new combustion power stations at or over 300 MWe[†] (the Guidance).

Guidance Requirements

1.2.7 Under the CCR Policy, and as part of a CCR Feasibility Study which will accompany the Consent application, the Guidance states that Consent applicants are required to demonstrate:

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

1.2.8 Further to this: "*if Applicant's proposals for operational CCS involves the use of hazardous substances, they may be required to apply for Hazardous Substances*

[*] *Guidance on Carbon Capture Readiness and Applications under Section 36 of the Electricity Act 1989 (DECC, April 2009)*

[†] *Carbon Capture Readiness (CCR) A Guidance Note for Section 36 Electricity Act 1989 Consent Applications (DECC, November 2009)*

Consent (HSC). In such circumstances they should do so at the same time as they apply for Section 36 Consent".

1.2.9 This CCR Feasibility Study has been undertaken to fulfil these requirements.

1.2.10 Within this CCR Feasibility Study, it is assumed that the carbon capture approach most appropriate will be post-combustion capture based on chemical absorption using amine solvents. This best represents PB's current view of carbon capture technologies.

SECTION 2

LEGAL CONTEXT AND METHODOLOGY

2 LEGAL CONTEXT AND METHODOLOGY

2.1 EU Directive on Geological Storage of Carbon Dioxide

2.1.1 The EU agreed the text of a new EU 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 CCS Directive) in the Official Journal of the European Union on 5 June 2009 and the Directive came into force on 25 June 2009.

2.1.2 The CCS Directive requires an amendment to Directive 2001/80/EC (commonly known as the Large Combustion Plants Directive (LCPD)) such that Member States are to ensure that operators of all combustion plants with an electrical capacity of 300 MW or more (and for which the construction / operating licence was granted after the date of the CCS Directive) have assessed whether:

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

2.1.3 An assessment of whether these conditions are met is then to be submitted to the relevant competent authority. The competent authority shall then decide if the conditions are met on the basis of the assessment and other available information.

2.1.4 If the conditions are met, the competent authority shall ensure that suitable space is set aside for the equipment necessary to capture and compress CO_2.

2.1.5 The relevant sections of the Directive are attached in Appendix A.

2.2 UK Government – Towards Carbon Capture and Storage

2.2.1 In the UK the relevant competent authority in respect of energy matters is the DECC. DECC must ensure the CCS Directive is implemented. It is also free to impose more stringent regulations on power plants within the UK.

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

2.2.3 A response to this consultation was published in April 2009, alongside draft Guidance for applicants seeking consent for new combustion power stations at or over 300 MWe (the draft Guidance[3]). The draft Guidance aimed to reflect the Government's new CCR Policy, and was subject to an eight week consultation period which ended on 22 June 2009.

2.2.4 The responses from the consultation period were incorporated into the final Guidance published in November 2009 (the Guidance[4]).

CCR Policy

2.2.5 The UK Government recognises that CCR is a preparatory step towards CCS.

2.2.6 Their CCR Policy applies to new combustion plants with a generating capacity of 300 MWe or more, with effect from 23 April 2009. Under this Policy, all combustion plants at or over 300 MWe must be CCR and must set space aside to accommodate future CCS equipment.

2.2.7 The CCR Policy implements Article 34 of the CCS Directive (discussed in Section 2.1) which requires a number of assessments to be undertaken.

[3] *Guidance on Carbon Capture Readiness and Applications under Section 36 of the Electricity Act 1989 (DECC, April 2009)*
[4] *Carbon Capture Readiness (CCR) A Guidance Note for Section 36 Electricity Act 1989 Consent Applications (DECC, November 2009)*

CCR Policy Requirements

2.2.8 Under the new CCR Policy, and as part of a Consent Application, the Guidance states that Section 36 Consent applicants will be required to demonstrate:

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

2.2.9 Further to this: "*if Applicant's proposals for operational CCS involves the use of hazardous substances, they may be required to apply for Hazardous Substances Consent (HSC). In such circumstances they should do so at the same time as they apply for Section 36 Consent*".

2.2.10 If granted consent, the Guidance states that operators will be required to:

- "*Retain control over sufficient additional space on or near the site on which to install the … carbon capture equipment, and the ability to … use it for that purpose; and*
- *Submit reports to the Secretary of State for DECC as to whether it remains technically feasible to retrofit CCS to the Power Station. These reports will be required within 3 months of the commercial operation date of the Power Station (so avoiding any burden on the operator with an unimplemented Consent) and every two years thereafter until the plant moves to retrofit CCS*".

Verification of CCR

2.2.11 Based upon Annex C of the Guidance, Table 1 provides a checklist of the information to be included in a CCR Feasibility Study for a '*New Natural Gas Combined Cycle Power Station using Post-Combustion Solvent Scrubbing*'. The Table indicates the location of evidence in this CCR Feasibility Study.

TABLE 1: CHECKLIST OF INFORMATION TO BE PROVIDED IN A CCR FEASIBILITY STUDY

	Annex 1C Reference	***Section of this CCR Feasibility Study***
C1	Design, Planning Permissions and Approvals	6.2.1
C2	Power Plant Location	6.2.5
C3	Space Requirements	6.2.8
C4	Gas Turbine Operation with Increased Exhaust Pressure	6.2.14
C5	Flue Gas System	6.2.21
C6	Steam Cycle	6.2.25
C7	Cooling Water System	6.2.44
C8	Compressed Air System	6.2.60
C9	Raw Water Pre-treatment Plant	6.2.63
C10	Demineralisation / Desalination Plant	6.2.65
C11	Waste Water Treatment Plant	6.2.69
C12	Electrical	6.2.73
C13	Plant Pipe Racks	6.2.76
C14	Control and Instrumentation	6.2.79
C15	Plant Infrastructure	6.2.81

Point C16 of Annex C, "'Essential' Capture-Ready Requirements: Post Combustion Amine Scrubbing Technology based CO_2 Capture" notes that the above points can be adapted to include other liquid solvent mixtures for CO_2 capture which may reasonably be expected to be commercially available at the time of retrofit for which reliable performance estimates are currently available.

2.2.12 Annex C of the Guidance is provided in Appendix B. Further to the above checklist, a summary of where the information required by the DECC, as per the Guidance published in November 2009 is provided in Appendix C.

2.2.13 It should be noted that this CCR Feasibility Study has been prepared to show that the move from CCR to CCS is both technically and economically feasible for GEC within its 35 year operating lifetime. Accordingly, this CCR Feasibility Study addresses:

- The availability of suitable storage sites;
- The technical feasibility of transport facilities;
- The technical feasibility of retrofit;
- The economic feasibility of transport facilities and retrofit; and,
- Establishes that there is suitable space for CCS equipment at the GEC site.

2.2.14 In respect of the economic feasibility for transport facilities and retrofit, it is considered that these are expected to become economically feasible at some point in the future given:

1. The recent and likely future developments in CCS technology, much of which will stem from the proposed CCS Demonstration Competition to be funded by DECC and the EU;
2. The likely long-term movements in the price of carbon;
3. The proposed treatment in Phase III of the EU ETS of carbon which is emitted, captured and stored; and, in particular,

4. The UK Government's stated commitment to establishing the necessary Economic and Regulatory Framework for CCS.

2.2.15 As the eventual deployment of CCS will involve major infrastructure changes on site, a separate Consent application will be required in the future. At this time, a further Environmental Impact Assessment (EIA), and resulting Environmental Statement (ES), will be submitted. This will cover all the likely significant environmental impacts of operational CCS for GEC and will include a greater level of detail regarding the eventual selected capture technology, transport and storage arrangements.

2.3 Approach

2.3.1 Within this CCR Feasibility Study, the following approach was used:

- A high level design concept for GEC was established;
- Thermal modelling exercises have been carried out by PB to identify the likely CO_2 capture requirement for GEC;
- A preferred carbon capture technology was identified for retrofit and its likely impact on the performance of GEC was both thermodynamically and chemically modelled using information provided by a number of possible process providers;
- The size of the main carbon capture equipment was established using the above thermal modelling and information from possible process providers, and illustrative site plans were prepared to confirm that the carbon capture equipment would fit into the land currently available (approximately 4.7 hectares (ha) / 11.6 acres);
- Geological storage sites with storage capacities capable of accepting the CO_2 output from GEC over a 35 year period were identified;
- A preferred route for the transportation of the CO_2 from the GEC site to a geological storage site was identified; and
- An economic assessment (which accounted for all the economic assessment criteria set out in the Guidance) was carried out to estimate the price of EU Allowances for CO_2 which were necessary to make GEC feasible with CCS.

2.4 Report Structure

2.4.1 Based on the CCR Policy Requirements detailed previously in Section 2.2, this report is structured as follows:

Introductory Information:

Section 1. **Introduction**
Provides an overview of GEC and the need for a CCR Feasibility Study

Section 2. **Legal Context**
Discusses the CCR Feasibility Assessment in terms of the requirements of the Government’s new CCR Policy and the approach undertaken

Section 3. **Proposed Development**
Provides discussion, together with calculations of the flue gas generated and initial size requirements of the CCS chain

Carbon Capture Technology Information:

Section 4. **Proposed Capture Plant Technology**
Based on post-combustion amine scrubbing

Technical Assessments:

Section 5. **Technical Assessment – CCS Space Requirements**
Includes the key information required by the Guidance

Section 6. **Technical Assessment – Retrofitting and Integration**
Includes the key information required by the Guidance

Section 7. **Technical Assessment – CO_2 Storage Area**
Includes the key information required by the Guidance

Section 8. **Technical Assessment – Transport**
Includes the key information required by the Guidance

Economic Assessment:

Section 9. **Economic Assessment**
Includes the key information required by the Guidance

Additional Information:

Section 10. **Requirement for Hazardous Substances Consent**

Conclusions:

Section 11. **Conclusions**

2.4.2 Supporting information is provided in the Appendices.

SECTION 3

PROPOSED DEVELOPMENT

3 PROPOSED DEVELOPMENT

3.1 Gateway Energy Centre Combined Cycle Gas Turbine (CCGT) Power Plant

3.1.1 The GEC site, approximately 11.3 hectares (28.0 acres) in size, is situated on the north bank of the Thames Estuary and lies approximately 6 km east of the A13. The GEC site includes the land to be set aside for the purposes CCR if required in the future. The A1014 dual carriageway (The Manorway) lies approximately 0.5 km to the north of the site and runs east to west to provide a link with the A13, which in turn links in with the M25 at Junction 30.

3.1.2 The nearest residential settlements are at Corringham and Fobbing which lie approximately 4 km to the west, Canvey Island which lies approximately 5 km to the east and Basildon which lies approximately 7 km to the north.

3.1.3 The Ordnance Survey (OS) Grid Reference of the centre of the site is approximately 573209, 182165. The site location is shown in Figure 1.

3.1.4 To the east of the GEC site lies the existing 800 MWe CCGT Power Station owned and operated by Coryton Energy Company Limited (CECL Power Station), a subsidiary of the InterGen group, (700 m east) and the existing Coryton Oil Refinery (950 m east) owned and operated by Petroplus.

3.1.5 GEC will be located on land within the LG Development.

3.1.6 The LG Development will involve the redevelopment of the former Shell Oil Refinery site at Shell Haven near Corringham and Stanford-le-Hope (Essex) together with associated transport connections, reclamation of part of the foreshore of the River Thames Estuary, and dredging of higher parts of the navigation channel within the Estuary to accommodate the passage of container vessels.

3.1.7 Once complete the LG Development is expected to become the most advanced deep-sea container port in the UK, capable of handling approximately three and a half million cargo containers annually. A Logistics and Business Park will serve the Port and offer some nine million square feet of advanced business space for distribution and manufacturing companies.

The Proposed Configuration and CO_2 Output

3.1.8 The total electrical output of GEC will be approximately 900 MWe at typical site rated conditions.

3.1.9 As carbon capture technology is essentially blind to the details of the upstream power generation process, the only output of the modelling process that is required for carbon capture plant sizing are details of the CO_2 and flue gas flow rates and the temperature of the flue gas.

3.1.10 Internal power plant modelling exercises have been conducted by PB in order to determine CO_2 and flue gas intensity factors for various sized power generating plant. These intensity factors have been used in this CCR Feasibility Report to estimate maximum and average flue gas and CO_2 flowrates for the GEC. These flowrates are key parameters used in the sizing of the carbon capture plant.

3.1.11 The CO_2 and flue gas intensity factors were modelled assuming a power plant configuration of two single shaft CCGT units assuming values for two gas turbines, two steam turbines with a triple pressure reheat steam cycle and Air Cooled Condensers (ACCs).

3.1.12 However, it should be noted that this arrangement may not be that used in the final design of GEC and the selection of the arrangement of the steam turbine / s (in terms of the single shaft / multi shaft configuration proposed for GEC) has a negligible impact on the actual sizing of the carbon capture plant.

3.1.13 In addition, it should be noted that as details of the final design of the GEC are not available, and the gas turbine model is not selected, modelling was undertaken using a range of different gas turbines currently available.

3.1.14 The carbon capture plant and transportation chain will be sized using the maximum possible CO_2 and flue gas intensity factors, which will be used to determine CO_2 and flue gas flowrates. The storage requirement will be estimated using the CO_2 and flue gas flow intensity factors based on average ambient conditions, coupled with expected average power output.

3.1.15 Table 2 indicates the flue gas and CO_2 intensity factors, power ratios and flue gas temperatures for the range of different gas turbines modelled.

3.1.16 The power ratio is used to determine the maximum and average flowrates. The power ratio is the ratio between the total electrical output of GEC at typical site rated conditions and the total electrical output of GEC under reduced atmospheric temperature conditions. A lower atmospheric temperature will increase the total electrical output of power generating plant and with this comes a corresponding increase in CO_2 flowrate. The power ratio is used to estimate a maximum CO_2 flowrate which could be expected from GEC under worst case conditions. The annual average temperature and the reduced atmospheric temperature used in the modelling were 9.5°C and 5°C[**] respectively.

TABLE 2: MAXIMUM FLUE GAS AND CO_2 INTENSITIES FOR DIFFERENT GAS TURBINE MANUFACTURERS

	Flue Gas Intensity	CO_2 Intensity	Power Ratio
	(t/h/MW)	(t/h/MW)	
Manufacturer A	5.45	0.350	1.017
Manufacturer B	5.92	0.352	1.014
Manufacturer C	5.57	0.353	1.020

3.2 Gateway Energy Centre with the Addition of CCS

3.2.1 There are two Options that could be considered for the carbon capture plant for GEC that would influence the sizing of the carbon capture plant. These are referred to as Options A and B, and are related to the way steam is generated for the carbon capture process. In brief:

- Option A: Steam for the carbon capture process is taken from the steam cycle of the GEC.
- Option B: Steam for the carbon capture process is generated by auxiliary boilers.

3.2.2 Option A would impose greater requirements in terms of retrofitting when carbon capture equipment is installed. For example if a largely standard CCGT design for GEC is installed (such as a single shaft ACC arrangement), then after retrofitting for carbon capture the power plant may be less efficient than had a ‘non-standard carbon capture-optimised’ CCGT design been originally installed. However, a ‘non-standard carbon capture-optimised’ CCGT design would likely incur an efficiency penalty during CCGT-only operation.

3.2.3 Based on the information in Table 2, for Option A the maximum CO_2 flowrate is estimated to be 90.0 kg/s. The average CO_2 flow rate at average ambient conditions is estimated to be 88.3 kg/s.

[**] *It should be noted that whilst ambient temperatures will fall below 5°C, this value was selected to simulate the effect of the anti-icing equipment on the gas turbine inlet air temperature.*

3.2.4 Option B would require minimal changes to be made to GEC in terms of retrofitting when carbon capture equipment is installed. However, additional gas would be required for the auxiliary boiler, which could in turn increase the carbon capture requirement if the additional CO_2 in the boiler flue gases was combined with the flue gases from the power station flue prior to entering the carbon capture plant.

3.2.5 As such, Option B would increase space requirements compared to Option A by approximately 21 per cent for GEC with fin-fan cooling. This is discussed further in Section 5.

3.2.6 The expected percentage increase in the CO_2 and flue gas flow rates for Option B would be approximately 20 per cent and 9 per cent respectively. Therefore, for Option B the maximum CO_2 flowrate is estimated to be 108 kg/s. The average CO_2 flow rate at average ambient conditions is estimated to be 106 kg/s.

3.2.7 Whilst both Option A and Option B are discussed as potentially being available for GEC, Option A is the main focus of this report. There are several reasons for this approach.

Efficiency
The net efficiency of the combined CCGT and carbon capture plant is best if the integrated option (Option A) is implemented. This is an inherent advantage of Option A because the CCGT plant is in effect converted to a CHP plant.

Emissions
Even with the flue gases from the auxiliary boilers of Option B being treated in the carbon capture plant, it still has a worse CO_2 intensity (t/h per MW) than Option A.

Land Estimates
Currently, land area estimates for Option B are greater than for Option A. Whilst it is probable that these estimates will be reduced by the time of actual carbon capture implementation (due to improvements in technology and developments in plans), to avoid overestimating the land required at the CCR stage the more compact Option A will be considered.

Available Information
The majority of work carried out on post combustion carbon capture from power generating plant to date has focussed on the integrated approach detailed in Option A. This means more cost and technical information on this option exists.

3.2.8 Further details on Options A and B are provided in Section 6.

3.3 Estimation of Size of Carbon Capture Chain for Gateway Energy Centre

3.3.1 It is expected that the carbon capture plant eventually installed would capture up to 90 per cent of the CO_2 in the flue gases, with the actual amount dependent upon the temperature of the carbon capture process and the amount of process cooling available.

3.3.2 This CCR Feasibility Study has assumed that the carbon capture plant would incorporate a gas-gas re-heater. This is, in effect, a heat exchanger which cools down the flue gases entering the carbon capture plant with the flue gases exiting the carbon capture plant. This results in a higher ‘clean gas’ (i.e. flue gases with CO_2 removed) exit temperature, improving dispersion in the air, and lower process cooling requirements of the carbon capture plant.

3.3.3 However, it should be noted that a gas-gas re-heater may result in some leakage of flue gas from the incoming side to the exit side. For the purposes of this CCR Feasibility Study this leakage has been assumed to be 3 per cent, which represents the typical value for such equipment in the new and clean condition. However, over time, the leakage will increase slightly, resulting in the carbon capture plant having spare capacity.

3.3.4 The sizing of the CCS chain for Options A and B (including capture, compression / liquefaction, transport and storage) is based on the information presented in Table 3.

Option A

TABLE 3: SIZING OF CCS CHAIN FOR OPTION A

CCS Chain Component	***Units***	***Amount*** *Average (Max.)*
CO_2 Generated	kg/s	88.3 (90.0)
CO_2 Loss in Gas-Gas Re-Heater (assuming 3 per cent loss)	kg/s	2.65 (2.70)
CO_2 Captured (assuming 90% Capture)	kg/s	77.1 (78.6)
	t/hr	278 (283)
	t/day	6670 (6790)
CO_2 Stored (Assuming 75 per cent lifetime capacity factor[††] of GEC)	Mt/year	1.83
Total CO_2 Stored (Assuming 35 years of capture)	Mt	64.0

3.3.5 Therefore, for operation with Option A, the carbon capture chain should be capable of handling a maximum flow rate of approximately 90.0 kg/s which may occur whenever GEC is operating at full load. On this basis, the capture chain should be capable of processing up to a maximum of 6790 t/day.

3.3.6 The total annual throughput for the carbon capture chain will vary, and be dependent upon the operational profile for GEC. With a 75 per cent lifetime capacity factor, the total amount of CO_2 to be stored over the lifetime of GEC (expected to be 35 years) is therefore approximately 64.0 Mt.

Option B

3.3.7 For operation with Option B the CCS chain should be capable of handling a maximum captured flow rate of approximately 108 kg/s which may occur whenever GEC is operating at full load. On this basis, the capture chain should be able to process and store up to a maximum of 7880 t/day.

3.3.8 As for Option A, the total annual throughput for the CCS chain will vary, and be dependent upon the operational profile for GEC. With a 75 per cent lifetime capacity factor, the total amount of CO_2 to be stored over the lifetime of GEC (expected to be 35 years) is therefore approximately 74.0 Mt.

[††] *This is the expected operational load on GEC over its lifetime. Note this is different to the availability of GEC which is estimated in the Environmental Statement to be 93 per cent.*

SECTION 4

PROPOSED CAPTURE PLANT TECHNOLOGY

4 PROPOSED CAPTURE PLANT TECHNOLOGY

4.1 Current Understanding

4.1.1 The current understanding is that the carbon capture plant would not be installed until CO_2 capture is either mandated or economically beneficial.

4.1.2 A number of carbon capture technologies currently exist and, at the time of eventual installation, it is highly probable that the number of technologies will have increased. However, this study focuses solely on the technology that is closest to commercial deployment at present in order to demonstrate immediate CCR.

4.1.3 As such, this CCR Feasibility Study focuses on currently available technology, rather than speculating on any future developments that may be available when the carbon capture plant is ultimately installed. Whilst many of these future developments in carbon capture technology are likely, it would be hard to argue that a plant was CCR if it was dependent on uncertain future technical development.

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

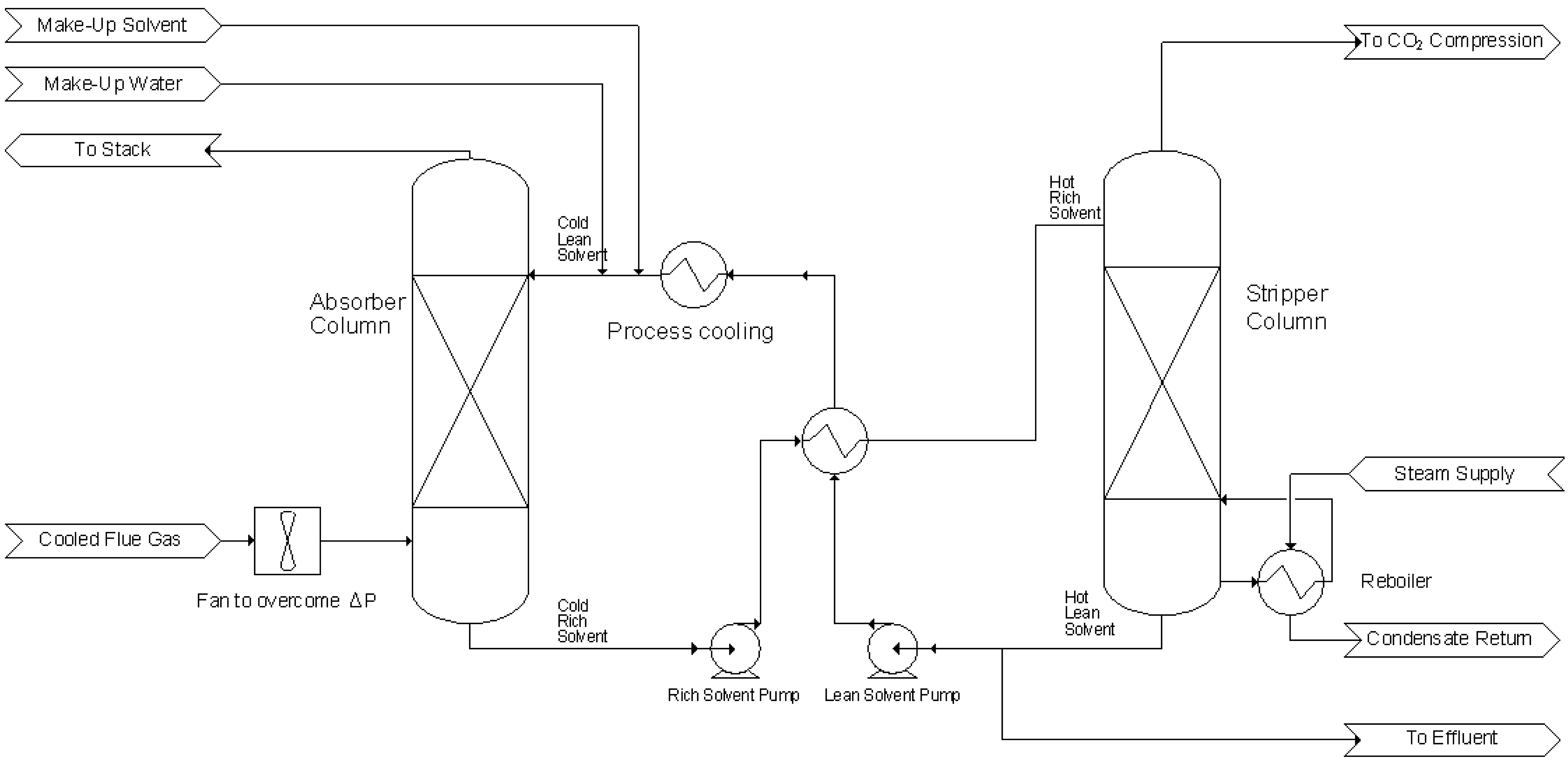
4.1.5 This technology may be regarded as commercially available but has not yet been commercially proven for large-scale power plant applications. However, it is the belief of PB that no technical barriers exist to extending existing experience to a scale appropriate to this CCR Feasibility Study for GEC.

4.2 Post-Combustion Amine Scrubbing

4.2.1 The post-combustion amine scrubbing carbon capture process on which this technical assessment is based consists of the following main process stages:

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

4.2.2 Figure 2 shows a schematic of post-combustion capture using chemical absorption based on amine solvents (typically MEA), commonly referred to as amine scrubbing. A brief description of this process is provided here.



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• CLIENT/PROJECT
GATEWAY ENERGY CENTRE

• TITLE
SCHEMATIC OF POST COMBUSTION CAPTURE– BASED ON AMINE SOLVENTS

• DATE 16/02/10
• SCALE 1:2000 @ A3
• CAD REF

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• DRAWING NUMBER
FIGURE 2 –

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4.2.3 Post-combustion, the flue gases are cooled for processing in the carbon capture plant. Options for flue gas cooling include gas-gas re-heaters or direct cooling with water. After cooling, the flue gas is blown through an absorber column where it comes into contact with the liquid amine solvent. Up to approximately 90 per cent of the CO_2 in the flue gas is chemically absorbed through acid-base neutralisation reactions with the amine. This creates a CO_2 rich stream of liquid solvent. The CO_2 rich solvent is pumped out of the absorber column and is heated in a heat exchanger before entry into a stripper column.

4.2.4 In the stripper column the solvent is heated further by the condensation of steam in the reboiler. The amine can absorb less CO_2 at higher temperatures, so heating the solvent releases the CO_2 as a gas. The lean liquid solvent is pumped from the bottom of the stripper, cooled in the heat exchanger and further cooled before re-entry to the absorber. The CO_2 gas, containing a large quantity of steam, exits at the top of the stripper. It is cooled to remove the steam and compressed or liquefied for transport. Steam and water removed from the CO_2 stream are returned to the capture plant.

4.2.5 Amine absorption plants are expected to capture up to approximately 90 per cent of the CO_2 in a CCGT plant flue gas stream and can result in an end CO_2 purity of over 99 per cent based on the experience from similar technologies in the chemical processing industry.

Carbon Capture Technology Requirements

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

4.2.7 Additionally, steam is needed to regenerate the amine solvent. In the case of an integrated carbon capture plant (presented as Option A in this CCR Feasibility Study), this steam would otherwise be expanded in the CCGT steam turbine to generate power and hence the carbon capture plant imposes a power penalty through its steam heat requirement.

4.2.8 This combination of auxiliary loads and steam required by the chemical absorption technique causes a significant reduction in the net electrical power output and efficiency of the CCGT. This has further impacts on the economics which are then required to be restored, for example through the implementation of CO_2 reduction revenues.

4.2.9 Additionally, substances such as particulate matter (PM), sulphur dioxide[7] (SO_2), nitrogen dioxide (NO_2) and oxygen (O_2) have a detrimental effect on the carbon capture process. The effects range from reduction in efficiency to the generation of solids within the carbon capture plant, such as heat stable salts (HSS). The HSS can cause problems such as foaming and therefore require filtration and addition of make-up solvent.

4.2.10 Flue gases from CCGT plants, such as GEC, typically contain ~14% excess oxygen and small amounts of NO_2. NO_2 forms HSS when it reacts with amine, however when levels of NO_2 are below 10 ppm (21 mg/Nm^3) these can be effectively countered. Currently, EU Legislation requires the NO_x level in the flue gas to be reduced to below 50 mg/Nm^3. As NO_x typically contains less than 10 per cent NO_2, the level of NO_2 in the GEC flue gas should not cause difficulty for the standard amine carbon capture processes. In addition, whilst oxygen also reduces the efficiency of the standard amine capture process, all calculations relating to the carbon capture in this CCR

[7] *It should be noted that the detrimental effects of SO_2 on the carbon capture process are very limited for gas fuel systems*

Feasibility Study are based on CCGT flue gases. As such, the quantity of oxygen has already been taken into account.

Carbon Capture Technology Improvements

4.2.11 In addition to other technologies, carbon capture technology providers are considering a number of methods for improving their processes. There are many methods currently suggested ranging from a simple method of incorporating heat recovery to more complicated methods such as flue gas recirculation[8].

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

4.2.13 As with alternative technologies, these possible improvements to the process have not been included in this report, apart from the generation of steam through supplementary firing which is considered in Option B. However, new developments in carbon capture technology will be reviewed on an ongoing basis as part of the Status Reports, with a view to incorporating developments in the updated design for the carbon capture plant for GEC.

4.2.14 Possible vendors for amine capture include: Mitsubishi Heavy Industries (MHI); Fluor Daniel (licence holder of the Economine FG process); Cansolv (recently acquired by Shell Global Solutions); Aker Clean Carbon; HTC; C&I Lummus (previously ABB Lummus); Siemens; and, Powerspan. Discussions (2008) with both Fluor Daniel and Cansolv indicate that it is technically feasible to build a carbon capture plant for a 1000 MW power output scale on gas firing, with a development time in the region of 12 months (once flue gas conditions are known) and a construction time of in the region of 36 months.

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

SECTION 5

TECHNICAL ASSESSMENT – CCS SPACE REQUIREMENTS

5 TECHNICAL ASSESSMENT – CCS SPACE REQUIREMENTS

5.1 Guidance

5.1.1 The Guidance states that the assessment of appropriate space to be set aside for CCS equipment will depend on:

- The type of capture technology selected;
- The size / number of power generating units;
- The input fuel for the power units;
- Decisions about whether the necessary CO_2 processing (for example compression) would be on or nearby the site;
- Ensuring the safe storage of chemicals;
- Avoiding congestion on site for safety, both during construction and operation; and
- In time, progress in developing the capture technologies so as to reduce the space required for the related equipment.

5.1.2 However, the Guidance states that "*since capture technologies have not yet been demonstrated on a commercial scale, it is not appropriate for Government to impose prescriptive requirements on the amount of space which should be set aside*".

5.2 Introduction

5.2.1 There is a large area of land on the GEC site which is to be specifically set aside for the future implementation and installation of carbon capture equipment, approximately 4.7 ha.

5.2.2 For the purposes of this CCR Feasibility Study, the sizing of the carbon capture equipment is based on Option A, detailed in the information provided in Table 3 .

5.2.3 For Option A, the calculations have indicated a requirement for CCS equipment capable of processing a maximum 90.0 kg/s of CO_2.

5.3 Methodology

5.3.1 The sizing and design of the carbon capture equipment for GEC has been based on information provided from:

- Process and compressor providers;
- GTPro, GTMaster and Thermoflex software modelling of generic power plant using a range of vendors with post-combustion carbon capture equipment (thermodynamic modelling);
- ProTreat modelling of carbon capture equipment (chemical modelling); and
- Excel-based carbon capture models developed by PB.

In the absence of technology / specific data, professional judgement was used to make various assumptions where required. For example, this was used in scaling of chemical processing industrial carbon capture units to those required by GEC.

5.3.2 The sizing of the internal area of the main CCS equipment has been based on the FluorDaniel Study 1999[***]. Based on these sizes, likely worst case assumptions were made about the external dimensions of this equipment based on information in the Fluor – Statoil Study 2005[†††]. The size of the balance of plant items are also based

[***] *Recovery of CO_2 from Flue Gases : Commercial Trends (October 1999)*

[†††] *Study and Estimate for CO_2 Capture Facilities for the Proposed 800 MW Combined Cycle Power Plant – Tjeldbergodden, Norway (April 2005)*

on the Fluor – Statoil Study 2005. The size of cooling equipment is based on information from industry standard thermodynamic modelling software.

5.3.3 In addition to the above, the sizing of the overall carbon capture plant takes into account publicly available information on indicative areas recommended, including the information provided in the Guidance which has been amended to suit GEC's nominal electrical output of approximately 900 MWe.

5.4 Illustrative Site Plan

5.4.1 In order to demonstrate that space is available and suitable for GEC to be considered CCR, an illustrative site plan has been prepared which indicate:

- The footprint of GEC;
- The location of the capture plant;
- The location of the CO_2 compression equipment;
- The location of the chemical storage facilities; and
- The exit point for the CO_2 pipeline.

5.4.2 An illustrative site plan detailing the equipment required for Option A has been prepared for this CCR Feasibility Study. The illustrative site plan can be seen in Figure 3-A. An illustrative site plan showing the area to be set aside for carbon capture is shown in Figure 3-B. The carbon capture plant for Option A is estimated to be approximately 3.1 ha.

5.4.3 The footprint of the carbon capture plant for Option B could be expected to increase by approximately 21 per cent with fin-fan cooling (i.e. 3.8 ha). As the land allocated for CCR in Figure 3-B is 4.7 ha, it is possible to say that there is adequate space to implement Option B in the future.

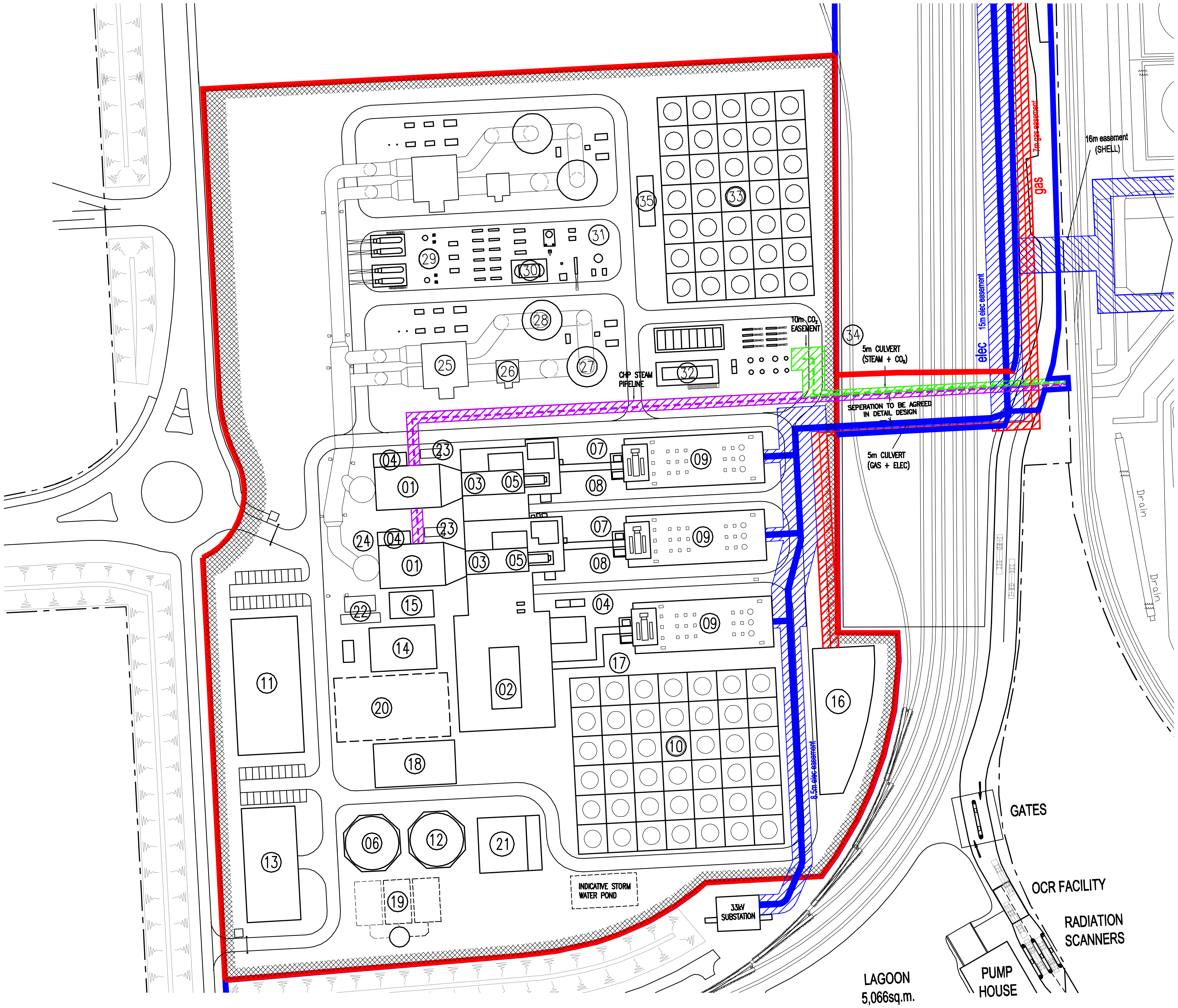
5.4.4 Whilst the illustrative site plan is drawn to scale, it should be noted that this is a CCR Feasibility Study and not a detailed design specification. Therefore the plans are illustrative only and show areas required for major plant items and buildings. The tender specifications for GEC will include requirements to ensure that the plant is ultimately CCR.

5.4.5 The space requirements will be reviewed on an ongoing basis as part of the Status Reports, with a view to incorporating developments in the updated design for the carbon capture plant for GEC.

5.5 Demonstration of Suitably Located Land

5.5.1 GECL has secured the use of land abutting the north of the CCGT site as part of the land agreement for the CCGT site for the purposes of installing carbon capture equipment if required in the future.

5.5.2 Indicative easements have also been agreed such that a CO_2 pipeline can be routed from the site. These are shown on the eastern side of the GEC site in Figure 3-A.



KEY

- STEAM/HOT WATER EASEMENT
- CO2 EASEMENT
- POWER EXPORT EASEMENT

LEGEND

01 HEAT RECOVERY STEAM GENERATOR
02 STEAM TURBINE AREA
03 GAS TURBINE AREA
04 CO2 LOW PRESSURE STATION
05 GAS TURBINE INLET FILTER
06 DEMINERALIZED WATER STORAGE TANK
07 CTG MAIN TRANSFORMERS
08 STATION SERVICE TRANSFORMER
09 SWITCHYARD
10 AIR COOLED CONDENSER
11 WAREHOUSE/MAINT/ADMIN/CONTROL BDLG
12 WATER TREATMENT
13 WATER/ FIREWATER STORAGE TANK
14 FIN FAN COOLERS
15 AUXILIARY BOILER
16 GAS CONDITIONING FACILITY
17 STG MAIN TRANSFORMER
18 CONTROL BUILDING
19 AUXILIARY BOILER FOR FUTURE CHP
20 POSSIBLE LAYDOWN/OPEN
21 GAS COMPRESSOR
22 AMMONIA OFFLOADING/STORAGE
23 AMMONIA INJECTION SKID
24 STACK
25 GAS/GAS HEAT EXCHANGER
26 BLOWER
27 DIRECT CONTACT COOLER
28 ABSORBER
29 STRIPPER
30 RECLAIMER
31 SOLVENT STORAGE TANK
32 CO2 COMPRESSOR HOUSE
33 FIN-FAN COOLERS
34 CO2 BATTERY LIMIT
35 CW PUMP HOUSE

CCS AREA = 47100sqm

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• CLIENT/PROJECT
GATEWAY ENERGY CENTRE

• TITLE
ILLUSTRATIVE SITE PLAN WITH CARBON CAPTURE

• DATE 03/11/09
• SCALE 1:2000 @ A3
• CAD REF

DRAWN BY DD
PRODUCED BY DD
CHECKED GM
APPROVED

• DRAWING NUMBER
FIGURE 3-A | –

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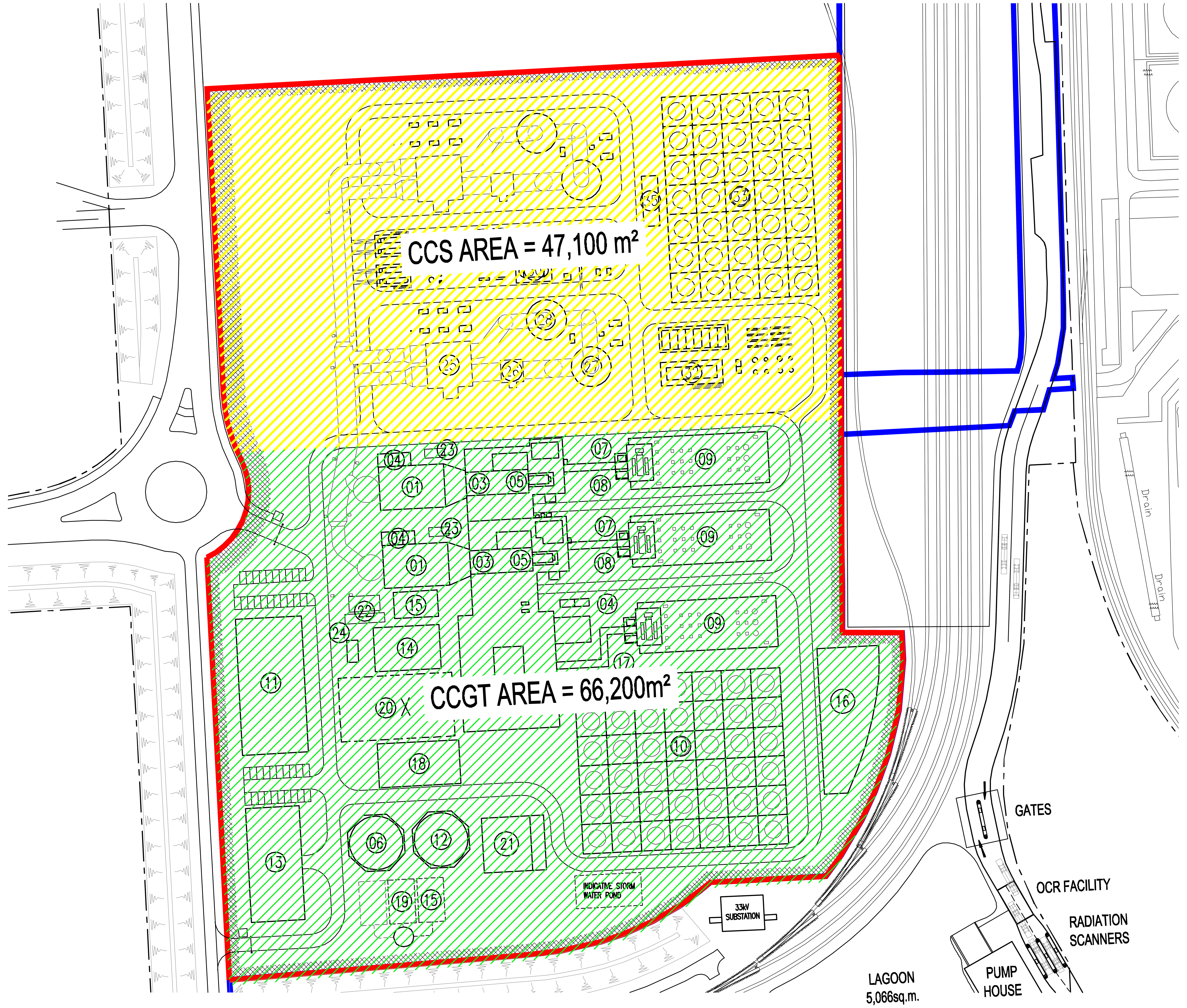

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• TITLE
ILLUSTRATIVE SITE PLAN WITH CARBON CAPTURE AREAS

• DATE 16/02/10
• SCALE 1:2000 @ A3
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FIGURE 3–B | –

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SECTION 6

TECHNICAL ASSESSMENT – RETROFITTING AND INTEGRATION OF CCS

6 TECHNICAL ASSESSMENT – RETROFITTING AND INTEGRATION OF CCS

6.1 Guidance

6.1.1 The Guidance states that the aim of this assessment is to demonstrate that GEC has been designed in such a way as to enable the subsequent retrofitting of carbon capture equipment.

6.1.2 The technical assessment of retrofitting in this CCR Feasibility Assessment has been made against the information provided in Annex 1C of the Consultation "Guidance on Carbon Capture Readiness and Applications under Section 36 of the Electricity Act 1989" (April 2009). This information has been summarised in Table 1.

6.1.3 However, the Guidance also states that the Government will not insist that an applicant must, when CCR turns to CCS, install the technology stated in their CCR Feasibility Study. This is due to the recognition that carbon capture technologies are still developing and operators should not be bound to retrofit a technology which is less effective or economic than those which may become available.

6.2 Technical Assessment

C1. Design, Planning Permissions and Approvals

6.2.1 The Guidance requires that

"*A pre-feasibility-level conceptual capture retrofit study should be provided for assessment, showing how the proposed CCR features would make adding post-combustion capture technically feasible. This should be accompanied by an outline plot level plan for the plant retrofitted with capture*".

6.2.2 The technical assessment of the retrofitting and integration of CCS for GEC has been undertaken on the assumption that carbon capture will be post-combustion capture using chemical absorption with amine solvents.

6.2.3 The discussion which follows in this Section aims to illustrate the technical feasibility for retrofitting this capture technology to GEC for the two Options identified. The technical feasibility assessment has been made against the checklist provided in Annex C of the Guidance. This is summarised in this CCR Feasibility Study in Table 1. The full checklist is provided in Appendix B.

6.2.4 In addition, an illustrative plot level plan is provided for Option A in Figure 3-A.

C2. Power Plant Location

6.2.5 The Guidance requires that

"*The work undertaken on CO_2 transport and storage should be referenced*".

6.2.6 Information has been provided on the location of GEC in Section 3. The most likely exit point for the captured CO_2 is shown in Figure 3-A.

6.2.7 Further discussion on the transport and storage of captured CO_2 is provided in Sections 7 and 8 respectively. It should be noted that the exit point for CO_2 has been placed to match the most likely on shore pipeline route which is discussed further in Section 8.

C3. Space Requirements

6.2.8 The Guidance states that:

"Space will be required for the following:

a) CO_2 capture equipment, including any flue gas pre-treatment and CO_2 drying and compression;

b) *Flue gas duct route to the CO_2 capture equipment;*

c) *Steam turbine island additions and modifications (e.g. space in steam turbine building for routing large low pressure steam pipe to amine scrubber unit);*

d) *Extension and addition of balance of plant systems to cater for the additional requirements of capture equipment;*

e) *Additional vehicle movements (amine transport, etc.); and*

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

6.2.9 In addition to the above, in terms of this CCR Feasibility Study, space is required for fin fan coolers to dissipate the heat removed during the carbon capture process.

6.2.10 The Guidance requires that

"*All of the provisions in a-f above will be implemented, including the provision of space and access to carry out the necessary works at the time of retrofitting without excessive interruptions to normal plant operation.*"

6.2.11 The provisions for a-f are:

a) The space requirements for the main items of CCS equipment, including flue gas pre-treatment by means of the direct contact coolers and CO_2 drying and compression are illustrated in the illustrative site plan provided in Figure 3-A.

b) The flue gas duct route from GEC to the carbon capture plant is referenced on the illustrative site plan provided in Figure 3-A.

c) The space required for any steam turbine additions (which would potentially be required if Option A were implemented) would be implemented via details in the tender specifications for GEC.

d) Figure 3-A includes adequate space for balance of plant systems, such as waste water neutralisation, and includes the oversized demarcations in the GEC site plan for the anticipated common systems. The requirements for the additional balance of plant systems common to both GEC and the carbon capture plant would be detailed in the tender specifications for GEC.

e) Figure 3-A includes space for additional plant infrastructure (including roads of 6 m width in reasonable proximity to the amine storage tank and to all major equipment) that would be required for both constructional and operational vehicle movements. The two roads on either side of the common plant area (stripper column section) are likely to be flush with grade level to allow the positioning of large cranes during construction.

f) Figure 3-A includes space for storage and handling of amines, including a solvent tank and solvent filter. Figure 3-A also shows the space required for the infrastructure for the transport of CO_2 to the GEC site boundary. Figure 3-A also shows an indicative easement to land outside the GEC site at the eastern LG Development site boundary for the purposes of a CO_2 pipeline.

6.2.12 In addition, the tender specifications for GEC will contain requirements to ensure that it is ultimately constructed CCR, including:

- Space for future addition of flue gas off take ducting, flue-gas diversion mechanisms and access for retrofit / maintenance;

- Space for flue gas duct route to carbon capture plant, including consideration of additional space for support of any potential overhead ductwork;
- Space for pipework and pipework support to carbon capture plant (likely to be positioned beneath flue gas ductwork), including space in the turbine hall;
- Space for steam off take, including space surrounding blanked-off off take ports for addition of off take pipework, including isolation and bypass valves and access for retrofit / maintenance (if required);
- Space for return route and pipework of condensate to feedwater system;
- Space for potential future increase in size of demineralisation plant to polish produced water from the carbon capture plant for external users; and
- Space for additional capacity for compressed air.

6.2.13 Further details on space requirements are provided in the discussion below.

C4. Gas Turbine Operation with Increased Exhaust Pressure

6.2.14 The Guidance states that:

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

6.2.15 Pressure drops to be expected include:

- The gas side pressure drop across the direct contact cooler and absorber – typically 40 to 100 mbar;
- The exhaust pressure drop across the HRSG and ducting – typically 30 to 35 mbar; and
- The pressure drop across the gas-gas re-heater – typically 10 to 20 mbar.

6.2.16 As such, the total pressure drop from gas turbine / HRSG transition piece to the gas-gas re-heater outlet is estimated to be at least 80 mbar. This applies equally to each absorber train, since common flue gas headers are likely to be used.

6.2.17 Whilst the actual effect of pressure drop varies with specific gas turbine models, generally speaking, an increase in exhaust pressure reduces the gas turbine output and efficiency. As an estimate, an increase in exhaust pressure of 25 mbar would result in a loss of electrical power output of approximately 10 MW.

6.2.18 As the maximum allowable gas turbine exhaust pressure drop is typically around 50 mbar, the design for the carbon capture plant in this CCR Feasibility Study has included a booster fan to overcome the additional pressure drop. The power requirement for this fan is approximately 6 MW and has been included in the carbon capture plant power requirement.

6.2.19 When the carbon capture plant is ultimately designed, detailed specifications for this fan will be developed. This would include provisions for the pressure drop across the direct contact cooler and absorber and the gas-gas re-heater, and the volume and mass flow rate of the flue gas into the absorber. This detailed information is not available at this stage.

6.2.20 Whilst it is not possible to provide specifications for the booster fan at this stage without performing a more detailed design of the carbon capture plant, there is an adequate provision of space on the carbon capture plant for its installation.

C5. Flue Gas System

6.2.21 The Guidance states that:

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

6.2.22 The space requirements for the flue gas ducting from GEC to the CCS equipment are illustrated in Figure 3-A.

6.2.23 This CCR Feasibility Study has included the provision of a gas-gas re-heater for cooling the flue gas entering the carbon capture plant and heating the clean flue gas prior to release from the stack. The gas-gas re-heater would raise the temperatures of the clean flue gases to up to approximately 90°C before discharge.

6.2.24 The provision of space for stand alone direct contact coolers will allow for the removal of any SO_x that may be present in the flue gases at the time of installing carbon capture equipment. SCR is not deemed to be required for the carbon capture process assumed in this CCR Feasibility Study as the LCPD Limits for NO_x will result in flue gas containing a quantity of NO_2 that will not impact on the carbon capture process.

C6. Steam Cycle

6.2.25 Steam is required for the stripping of CO_2 from the amine solvent in the carbon capture process.

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

6.2.27 Initial energy and saturated steam requirement estimates were obtained from three different vendors. These are shown in Table 4.

TABLE 4: ESTIMATES OF SATURATED STEAM REQUIREMENTS FOR CARBON CAPTURE PROCESS

	Unit	***Vendor A***	***Vendor B***	***Vendor C***
Steam Pressure	bar a	4	3.6	4.5
Specific Energy Consumption	GJ/tonne CO_2	2.9	2.95	<3.0
Steam Flow	kg/s	119	120	123

6.2.28 The highest steam temperature quoted by process providers is in the region of 148ºC. This equates to a pressure of 4.5 bar a as shown in Table 4 (Vendor C). Therefore, in order to cover steam pressure drop and allow for a margin, a steam pressure of 5 bar a was used for the base case steam pressure. As such, steam extraction for the base case carbon capture process was modelled at:

- Steam Pressure – 5 bar a;
- Steam Flow – 123 kg/s; and

- Specific Energy Consumption – 3 GJ/tonne CO_2.

6.2.29 As the extracted steam will be superheated, the extraction flow will be less than the design figure of 123 kg/s. The exact flow will be dependent on the: steam cycle; design steam conditions; steam turbine stage efficiencies; and, source of desuperheating water.

6.2.30 The following options for the provision of steam are possible and practicable:

- Option A – Steam taken from the Cold Re-Heat (CRH).

  This integrated approach would require retrofitting of the CCGT plant, but requires minimal design changes to the initial CCGT plant.
- Option B – Installation of auxiliary boilers or CHP units to produce the steam required.

6.2.31 The two Options can also be compared against the Base Case for GEC without carbon capture, which shows a net electrical power output of approximately 900 MW.

Option A

6.2.32 Within this Option, several off take options may exist, but the one chosen is that steam would be removed from the CRH as this is the most universally retrofittable option for any power plant arrangement.

6.2.33 In terms of retrofitting, this would require space for a off-take port on each CRH line as well increasing the de-superheating capability. If this is employed, steam could be provided at any pressure up to the pressure of the CRH. This does not require an extraction port from the steam turbine and is therefore independent of the choice of steam turbine manufacturer.

6.2.34 The effect of Option A on the performance of GEC is a reduction of net electrical output of 75 to 90 MW.

6.2.35 The decision not to include the consideration of extracting lower pressure steam is due to the nature of the modifications that would be required for retrofitting. Either major steam turbine extraction modifications would be required in the initial design, or for Intermediate Pressure (IP) / Low Pressure (LP) crossover extraction for multi-shaft arrangements, the extent of retrofit modifications external to the steam turbine casing (if possible) would require such alterations that no benefit is gained by installing off-take ports in the initial design.

6.2.36 In addition, if Option A is chosen and the operation of the carbon capture plant is incorporated with the CCGT power plant, this may require extra steam to be provided during some periods (e.g. if the carbon capture process calls for the storage of rich amine during periods of high electricity prices and stripping during periods of low electricity prices). These options have not been considered in the base case design. However it is recommended that these options are considered further during the design of the steam system.

Option B

6.2.37 Within this Option, steam for process would be provided by auxiliary boiler equipment. As the details of this boiler would not be required until the implementation of CCS, steam could potentially be provided at a wide range of pressures.

6.2.38 Option B would not have an impact on the performance of the GEC CCGT as a stand alone power station.

6.2.39 A variant on Option B would be to install a back-pressure steam turbine in addition to the boiler, thereby supplying the steam requirements for the carbon capture plant as well as electrical power in a Combined Heat and Power (CHP) arrangement. The electrical power could be controlled to match the carbon capture plant's electrical load by using a steam turbine bypass, but a more efficient operational mode would be to export excess power.

6.2.40 Due to the range of CHP options available for the carbon capture plant, Option B only considers a boiler as it represents the largest departure from the alternative integrated case (Option A).

Discussion of Options A and B

6.2.41 In terms of the energy penalty, a comparison between Options A and B will indicate the difference between the efficiency-driven integrated approach and the output-driven non-integrated approach.

6.2.42 Illustrative overall performance results (including the treatment of the boiler flue gases in the capture plant) utilising a base case power plant with a net power output of 874 MW and a net Lower Heating Value (LHV) efficiency of 56.9 per cent with carbon capture are as follows:

- Overall net power output of Option A is 763 MW at an LHV efficiency of 49.7 per cent.
- Overall net power output of Option B is 821 MW at an LHV efficiency of 44.6 per cent.

6.2.43 Steam will also be required during the reclaiming process, which will operate intermittently, concurrently with the carbon capture process. The steam required for reclaiming is typically at a higher pressure than that required for carbon capture, and would require a flowrate of the order of 7 kg/s. The steam system should therefore be designed to allow for the flow of this additional higher pressure steam, which like the 5 bar a supply, will most likely be provided via its own dedicated let down station on the carbon capture plant. .

C7. Cooling Water System

6.2.44 The Guidance states that:

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

6.2.45 The extra cooling duty is required for:

- Cooling the flue gases to absorber temperature (flue gas cooling);
- Cooling the lean amine before entry to the absorber (process cooling);
- Cooling of CO_2 / condensing of water in CO_2 product before and between compressor stages (inter-cooling); and,
- Cooling of carbon capture ancillary equipment (plant cooling).

Discussion of Carbon Capture Process Temperatures

6.2.46 If amine (in this CCR Feasibility Study MEA) is in contact with CO_2, the CO_2 will react with the amine and chemically absorb into it. The CO_2 capture process is driven by the fact that at lower temperatures more CO_2 will absorb into the amine than at higher temperatures. Therefore, in principal CO_2 is absorbed by cold amine and released when the amine is heated.

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

6.2.48 Table 5 gives indicative figures to illustrate this concept. Actual values will depend on various other parameters of the carbon capture process, such as: the particular amine used; the carbon capture process temperature; the pressure in the absorber and stripper; the residence time (i.e., the length of time the amine is in contact with the flue gas); the percentage of CO_2 in the flue gas; and, the amount of other substances.

TABLE 5: THE EFFECT OF TEMPERATURE ON CARBON CAPTURE RATES

	Flue Gas Temperature at inlet to the Absorber		
	35°C	***50°C***	***150°C***
Mol of CO_2 absorbed per Mol of MEA	0.53	0.50	0.10

6.2.50 As such, a carbon capture process operating between an absorber temperature of 50°C and stripper temperature of 150°C would be able to capture approximately 88 per cent of CO_2. One operating between an absorber temperature of 35°C and stripper temperature of 150°C would be able to capture approximately 90 per cent of CO_2. However it should be noted that these are indicative figures only and will depend on the various other parameters of the carbon capture process listed above.

6.2.51 Using air cooling, it is not feasible to design the fin-fan coolers to maintain the absorber temperatures at 35°C in summer. However, the air cooling has been sized such that the absorber operates at approximately 35°C at design average ambient conditions. The improved CO_2 removal during winter will to a large extent offset the poorer removal during summer.

6.2.52 In this CCR Feasibility Study, 35ºC was chosen as the base case. At this temperature, the extra cooling required for the capture plant is between 375 and 405 megawatts thermal (MWth).

6.2.53 The illustrative site plan in Figure 3-A includes provisions for fin-fan air cooling

Estimated Cooling Requirements

6.2.54 The cooling requirements for the carbon capture plant were estimated using information provided by vendors and from modelling using Thermoflex software. A closed loop cooling liquid system (possibly treated water or a glycol/water mixture) will transfer the heat between the cooling loads and the fin-fan air coolers.

6.2.55 The results from the Thermoflex modelling indicate that the total carbon capture cooling loads for the two options are:

- Option A – Between 375 and 405 MW; and
- Option B – Between 465 and 500 MW.

6.2.56 This agrees with information provided by the vendors.

6.2.57 For the purposes of this CCR Feasibility Study, the cooling liquid is cooled in A-frame fin-fan air coolers. The space requirement for the fin-fan coolers is approximately 16 m^2 per MW of cooling duty.

6.2.58 There will be no continuous make-up water requirements for cooling system.

6.2.59 When the carbon capture plant is operational, the load on the ACCs for GEC would be significantly reduced. The possibility of reducing the size of the ACCs and utilising this space to provide cooling for the carbon capture plant was considered. However, if this was implemented the possibility of subsequently operating GEC at full load without carbon capture would not be possible. This Option was therefore not considered further.

C8. Compressed Air System

6.2.60 The Guidance states that:

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

6.2.61 Based on the methodology in Section 5 and the information in the Fluor – Statoil Study 2005, the CCS equipment for GEC under both Options A and B would require additional compressed air at approximately 150 Nm^3/hr.

6.2.62 The additional compressed air requirement would be provided via a requirement in the tender specification for GEC to allow for extra space to be included. This could easily be included with the plan for GEC.

C9. Raw Water Pre-treatment Plant

6.2.63 The Guidance states that:

"Space may be required in the raw water pre-treatment plant area to add additional raw water pre-treatment streams as required."

6.2.64 It is not expected that water flow rate required by the carbon capture plant will be significant. However, provision of space for the additional water treatment capability is amply provided for in Figure 3-A at Item 13 due to the potential of supplying external customers with steam in the CHP scheme.

C10. Demineralisation / Desalination Plant

6.2.65 The Guidance states that:

"A supply of reasonably pure water may be required to make up evaporative losses from the flue gas cooler and / or scrubber. Estimates of this water requirement should be made and space allocated for the necessary treatment plant (and an additional water source be identified if necessary)."

6.2.66 Due to the absorber design operation temperature selected for this CCR Feasibility Study, the carbon capture plant is a net producer of water and no evaporative losses will be realised from the flue gas.

6.2.67 Additional demineralised water requirements will be to replace the water removed during the amine reclaiming process. At present this is estimated to be approximately 0.5 kg/s.

6.2.68 The provision of space for the increased water treatment capability is included in Figure 3-A at Item 13.

C11. Waste Water Treatment Plant

6.2.69 The Guidance states that:

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

6.2.70 The generation of effluents from the carbon capture process are discussed in Section 10.

6.2.71 In addition, it is expected that the final design of the carbon capture plant will have provisions to include for surface water drainage, contaminated surface water drainage which would drain to oil interceptors, and process drainage.

6.2.72 The required space for any waste water treatment is evident in Figure 3-A.

C12. Electrical

6.2.73 The Guidance states that:

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

6.2.74 Under Option A, the retrofitting of carbon capture equipment to GEC would lead to an estimated additional electrical requirement of 40 MW. At this stage it is suggested that this is met by a reduction of power from GEC to the grid, using auxiliary transformers deriving power from GEC. The electrical requirements for Option B would be met in a similar manner.

6.2.75 Whilst the actual electrical requirements at this stage are not final, it is expected that the space for additional electrical items associated with specific plant items (such as pumps, fans, etc) would be provided within the respective plant item areas illustrated in Figure 3-A. These items of plant are small in size and could be readily accommodated on site.

C13. Plant Pipe Racks

6.2.76 The Guidance states that:

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

6.2.77 Figure 3-A demonstrates the provisions which have initially been made for any additional pipework which may be required.

6.2.78 The provision of space for any additional pipework in GEC will be achieved via requirements in the tender specifications as detailed above.

C14. Control and Instrumentation

6.2.79 The control and instrumentation system for the carbon capture plant is anticipated to be incorporated into the Distributed Control System of GEC, i.e. the Control Room.

6.2.80 Figure 3-A demonstrates that space is available on the carbon capture plant for stand alone control equipment should this be required.

C15. Plant Infrastructure

6.2.81 The Guidance states that:

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

6.2.82 The provision of space for additional plant infrastructure is illustrated in Figure 3-A.

6.2.83 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.

6.2.84 Whilst the final provisions for plant infrastructure will be detailed in the final design of the carbon capture plant, at this stage it is envisaged this may include development phases, with the use of temporary road surfaces if required for construction vehicles.

6.2.85 In addition, the design basis for GEC ensures that the office and stores buildings are sized sufficiently for the additional requirements of the carbon capture plant.

Summary Discussion

6.2.86 The technical retrofitting of carbon capture and storage equipment to GEC will be reviewed on an ongoing basis as part of the Status Reports, with a view to incorporating developments in the updated design for the carbon capture plant for GEC.

SECTION 7

TECHNICAL ASSESSMENT – CO_2 STORAGE AREAS

7 TECHNICAL ASSESSMENT – CO_2 STORAGE AREAS

7.1 Guidance

7.1.1 The Guidance states that, at the present time, the simplest and most appropriate means of demonstrating there are "no known barriers" to storage is by delineating on a map a suitable storage area in either the North Sea or Morecambe Bay (East Irish Sea Basin (EISB)). 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 Department of Trade and Industry's (DTI) 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 D of the Guidance.

7.1.2 The Guidance states that the initial choices of storage areas made at the CCR stage will not be binding, and there will be no requirement for applicants to obtain exploration / storage licences or to nominate a specific storage site. This will enable storage plans to be refined and reviewed as a greater amount of information becomes available.

7.1.3 The Guidance also notes that, in time, a storage market may develop in which operators of combustion plants may enter agreements with specialist CO_2 storage operators. However, Consent applications at the CCR stage may not make the assumption that they will be able to outsource such arrangements. Nevertheless, any supporting evidence on which to base an outsourcing proposal may usefully be included.

7.2 Proposed Storage Areas

7.2.1 In order to determine any potential storage sites for CO_2 captured from GEC, it is necessary to have an idea of the amount of CO_2 that is required to be stored.

7.2.2 Based on the calculations detailed in Section 3 for Option A and Option B any storage site would have to be capable of storing approximately 64.0 Mt or 74.0 Mt of CO_2 respectively.

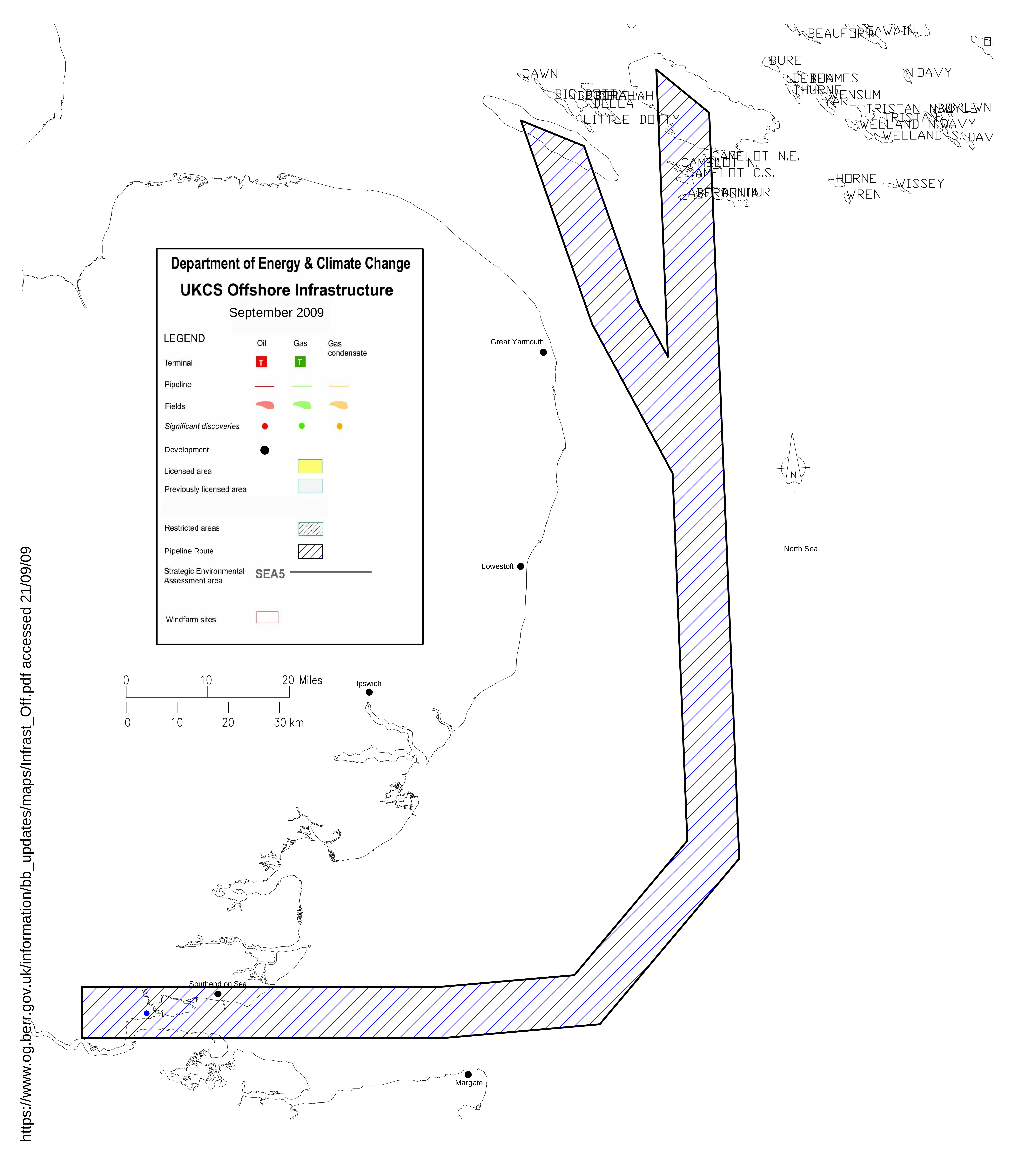
7.2.3 Based on the DTI Study 2006, the Hewet (L Bunter) and Leman gas fields in the South North Sea (SNS) basin are potential storage areas for the CO_2 generated by GEC.

7.2.4 The location of these storage areas is illustrated in Figure 4.

7.2.5 The Hewet (L Bunter) gas field has a capacity of 237 Mt CO_2 and the Leman gas field has a capacity of 1203 Mt CO_2. Based on the total storage requirements, Table 6 illustrates the percentage storage requirements on these two gas fields.

TABLE 6: PERCENTAGE CO_2 STORAGE REQUIREMENTS

	Option A ***64.0 Mt CO_2***	***Option B*** ***74.0 Mt CO_2***
Hewet (L Bunter) Gas Field 237 Mt CO_2	27.0%	31.2%
Leman Gas Field 1203 Mt CO_2	5.3%	6.2%



PARSONS BRINCKERHOFF

100 YEARS

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23/09/09

- CLIENT/PROJECT

GATEWAY ENERGY CENTRE

- TITLE

INDICATIVE LOCATION OF STORAGE AREAS OFFSHORE PIPELINE ROUTE

DATE	23/09/09	DRAWN BY	DD
SCALE	N/A	PRODUCED BY	DD
CAD REF		CHECKED	AP
		APPROVED	EA

- DRAWING NUMBER

FIGURE 4 | –

7.2.6 It is noted that in the future it is likely there may be competing interest for these identified storage sites as other carbon capture projects become operational. However, there are clearly a large number of storage sites which exist in the same region that are capable of storing the CO_2 from GEC.

7.2.7 Table 7 lists a number of storage sites, including those discussed above, in the SNS Basin that are identified in the DTI Study 2006.

TABLE 7: ADDITIONAL POTENTIAL STORAGE SITES IN THE SNS REGION

Field Name	***CO_2 Storage Capacity (Mt)***
Amethyst	63
Audrey	53
Barque	108
Clipper	60
Galleon	137
Hewett L Bunter	237
Hewett U Bunter	122
Indefatigable	357
Leman	1203
Ravenspurn N	93
Ravenspurn S	52
V Fields	143
Victor	70
Viking	223
West Sole	143
Total	**3064**

7.2.8 Whilst the decision as to which specific storage site to use will not be made until eventual implementation of CCS, Table 7 shows that the potential storage sites in the region have a storage capacity in excess of 3000 Mt CO_2. GEC would require less than 2 per cent of this storage capacity in the SNS Basin over its 35 year lifetime.

7.2.9 Another possibility in the future is that there will be a "CO_2 Network" in the region such that CO_2 from GEC, and other plants in the area, would be delivered to a "Central Hub". From this "Central Hub" the captured CO_2 would be delivered to a number of storage sites. The transport implications of this are discussed briefly in Section 8. Further discussion in Section 9 has been provided which includes this as a potentially viable option in the future as part of the economic assessment. In addition, if any updates are available in the future this option will be further reviewed.

7.2.10 The storage assessment will be reviewed on an ongoing basis as part of the Status Reports, with a view to incorporating any developments into an updated design for carbon capture at GEC.

SECTION 8

TECHNICAL ASSESSMENT – TRANSPORT

8 TECHNICAL ASSESSMENT – TRANSPORT

8.1 Guidance

8.1.1 The Guidance states that the feasibility of any proposed site for a new combustion station will be influenced by the availability of the transport route to the proposed storage area. At this stage, transport of CO_2 to the proposed storage area is expected to be via an onshore pipeline with either an offshore pipeline or transport by ship.

8.1.2 Within the CCR Feasibility Study, it should be demonstrated that a feasible route exists to remove the CO_2 from the site. Due to the remaining uncertainties surrounding the final specifications for pipelines, particularly concerning pipelines for the transport of dense phase CO_2, the Guidance states that plans should account for a 1 km wide corridor for the first 10 km from the capture site, with a subsequent 10 km wide corridor for the remaining distance to the coast. At the coast the pipeline would join the offshore pipeline or be boarded onto a ship for transportation to the storage site.

8.1.3 The Guidance also states that some parts of the identified transport corridor may unavoidably impinge on environmentally designated sites and that, in this case, mitigation measures should be briefly proposed and discussed in the CCR Feasibility Study to show how any such impacts would be minimised.

8.1.4 In terms of offshore transport by pipeline, the assessment in the CCR Feasibility Study should contain a similar degree of detail as for the onshore pipeline, i.e. a wide transport corridor route demonstrating how the storage area would be reached should be delineated on an appropriately scaled map.

8.2 Technical Assessment

Site Plan Considerations

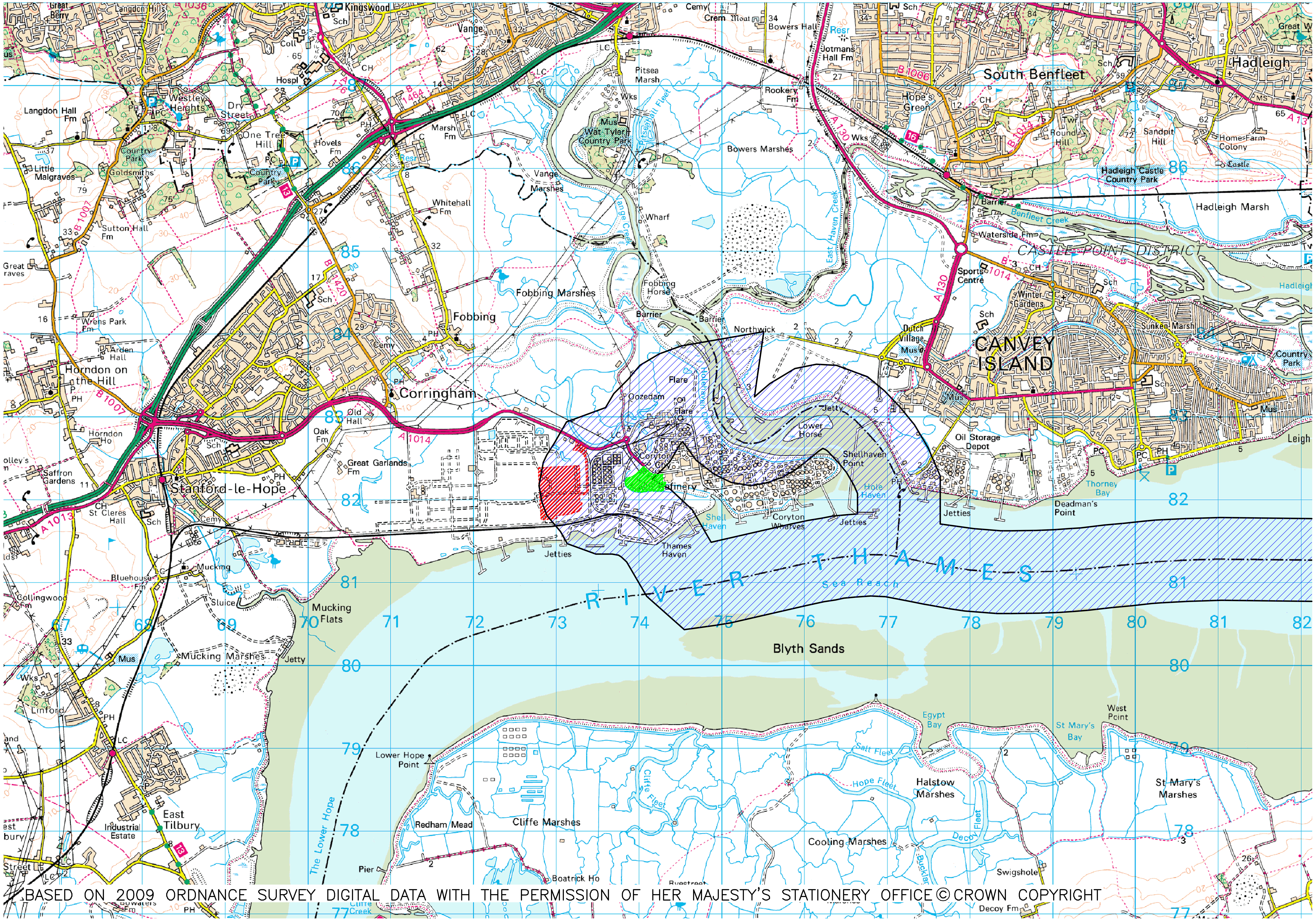
8.2.1 It should be noted that the exit point for the CO_2 pipeline has been placed to match the most likely onshore pipeline route which is discussed here. This is located to the eastern side of the GEC site. This is illustrated on Figure 3 which shows an indicative easement to land outside the GEC site at the eastern LG Development site boundary for the purposes of a CO_2 pipeline.

Transportation Overview

8.2.2 It is proposed that the CO_2 captured from GEC will be transported to the storage site via an onshore, then offshore pipeline.

8.2.3 Within the onshore and near-shore area there are two options regarding the pipeline route. Outwith these routes leaving the eastern side of the GEC site shown on Figure 3-A, these routes, which are illustrated in Figure 5, include:

- <u>The Holehaven Creek Option</u>
  A pipeline running to the north passing along the north side of the existing Coryton Oil Refinery, traversing Holehaven Creek, and then the River Thames; or
- <u>The Thames Haven Option</u>
  A pipeline running to the south and east following the existing railway line then passing into the River Thames at Thames Haven.



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LEGEND

GEC APPLICATION SITE LOCATION

CECL POWER STATION LOCATION

PIPE LINE ROUTES

0 1000m 2000m 3000m

BAR SCALE 1:50,000

REV	DATE	DESCRIPTION	BY	CHKD	APPD

• NOTES

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• CLIENT/PROJECT
GATEWAY ENERGY CENTRE

• TITLE
INDICATIVE ON-SHORE/NEAR SHORE PIPELINE ROUTES

• DATE 22/09/09
• SCALE N/A
• CAD REF

DRAWN BY DD
PRODUCED BY DD
CHECKED AP
APPROVED EA

• DRAWING NUMBER
FIGURE 5 | –

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8.2.4 The most likely pipeline option identified at present would be the Holehaven Creek Option. This comprises a pipeline leaving to the north passing along the north side of the Coryton Oil Refinery and into Holehaven Creek, before continuing via the River Thames on to the storage sites in the SNS Basin. This is the preferred potential route which will be focused on in this CCR Feasibility Study. The shorter Thames Haven Option is also discussed.

8.2.5 Both Options have the potential to link into E.ON's proposed 'Thames Cluster' detailed in "Capturing Carbon, Tackling Climate Change: A Vision for the CCS Cluster in the South East" (2009). The 'Thames Cluster' is 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. However, in line with the Guidance, it is not assumed in this CCR Feasibility Study that the transport of captured CO_2 will be able to be outsourced to the Thames Cluster.

8.2.6 After traversing Holehaven Creek and / or the River Thames, the offshore pipeline would run north east, past the site of the proposed Thames Array Wind Farm, before turning northwards to run parallel with the coast of East Anglia before linking in with the Hewet (L Bunter) or Leman storage sites, discussed in Section 7. The pipeline corridor for this route is shown in Figure 4.

Transportation Onshore

8.2.7 For the Holehaven Creek Option, from the indicative easement, the pipeline would run to the north of GEC for approximately 500 m before bearing right with the curve of the railway line. It would then run in-between the railway line and The Manorway (A1014) dual carriageway. The pipeline would cross the road at the most suitable point then trace the northern boundary of the Coryton Oil Refinery until reaching the transition point at Holehaven Creek indicated on Figure 5.

8.2.8 For the Thames Haven Option, from the indicative easement, the pipeline would follow the railway line south and east until reaching the transition point at the River Thames.

8.2.9 The main physical barriers encountered by the indicative easement and pipeline route include a railway line, a dual carriageway, access tracks, above ground pipeline racks, the flood wall on the bank of the River Thames and also a jetty. Bridging, tunnelling or boring are common techniques used to overcome such issues. It may also be possible to temporarily dismantle the jetty to allow installation of the pipeline to take place.

8.2.10 It is considered at this preliminary stage that there are no major physical barriers to running a CO_2 pipeline along either of the onshore / near-shore route options outlined.

8.2.11 The main onshore / near-shore environmental barriers include the area to the north of GEC which is lowland grazing marsh and contains a Site of Special Scientific Interest (SSSI). Holehaven Creek itself is also a designated SSSI. If, after consultation, it is not possible to run a trenched/dredged pipeline through these areas, other engineering options such as directional drilling or thrust boring techniques which avoid the need for trenching may be considered in order to mitigate any environmental impacts and to meet any relevant regulations. Where alternative boring is not possible the impact on protected wildlife species may be minimised by planning the installation around migration patterns and breeding seasons or by use of relocation programmes for certain species and habitats away from the pipeline route.

8.2.12 It is also noted that a triangular area, of approximately 5000 m^2, immediately north of The Manorway has been earmarked as amelioration land for habitat improvement and relocation of protected species from areas affected by the proposed LG Development project.

Transportation Offshore

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

8.2.14 A pipeline required to traverse the River Thames 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 upset existing habitats and are typically employed in environmentally sensitive areas. Again, if these alternative boring techniques are not feasible it may be possible to plan activities around breeding and migration seasons, or to consider species and habitat relocation.

8.2.15 Navigation of wind farm sites and associated cabling, dredging areas, existing pipeline infrastructures and disposal sites via the proposed route would be feasible. There is currently sufficient space between such sites to allow for the installation of a pipeline within the specified pipeline corridor shown in Figure 4. Shipping lanes are not anticipated to be a significant barrier to this form of transport; the pipeline would run along the seabed at a sufficient depth to allow ships to pass freely over. It is also worth noting the relevant skills, experience and techniques exist in the UK Natural Gas and Oil Industries to be able to complete such a project.

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

8.2.17 In addition, whilst not discussed in detail here, shipping of CO_2 may also be considered due to the close proximity of the LG Development Port facilities. Since there are a wider range of uncertainities surrounding this option (such as storage, consenting requirements and land use issues) it is not considered here. As the uncertainty surrounding this option decreases, this may be considered in the future as a transport option. This option will be reviewed on an ongoing basis as part of the Status Reports with a view to incorporating any developments into an updated design for carbon capture at GEC.

8.3 Transportation Safety Considerations

8.3.1 In terms of transport of captured CO_2 by pipeline, the mechanisms, hazards, consequences and probabilities of pipeline failure need to be understood so that safe design, commissioning and operation can be ensured.

8.3.2 The Guidance requires that a precautionary approach needs to be taken in respect of dense phase CO_2 at the CCR stage to ensure no foreseeable barriers exist along the proposed pipeline route. As such, it is required that dense phase CO_2 should be treated as a 'dangerous fluid' under the Pipeline Safety Regulations 1996 (PSR), under which the transport of CO_2 would classify the pipeline as a 'Major Accident Hazard Pipeline' (MAHP).

8.3.3 Inline with the PSR, the following considerations are to be made for the design of the CO_2 pipeline:

- A major accident prevention plan;
- A pipeline safety evaluation and technical safety risk assessment, including failure mechanisms, probability and consequence of failure. Mitigation measures will also be detailed;

- Operations, maintenance and emergency response policy, procedures and work instructions;
- Safe control of operations;
- Safe working in the vicinity of a high pressure pipeline;
- Asphyxiation risk assessment;
- Change of use notification required by HSE with a notification period up to 6 months;
- Emergency shut down valves to be fitted; and
- The relevant Local Authority to be notified and the Local Authority to have prepared an emergency plan.

8.3.4 Pending information on the classification of dense phase CO_2 and the final pipeline route, the above requirements are not deemed to be necessary at this stage and instead a precautionary approach in line with the PSR has been taken for the pipeline design and route. The aim of which is to account for the known mechanisms, hazards, consequences and probabilities of CO_2 pipeline failures including the following considerations:

- CO_2 is an asphyxiant and is also a known occupational health hazard;
- CO_2 should be regarded as corrosive. When it is combined with water carbonic acid is formed, therefore suitable materials must be selected during pipeline design to take account of this issue. In this CCR Feasibility Report it is assumed that within the compression in the carbon capture plant appropriate drying of the CO_2 takes place;
- It is likely that the CO_2 transported in the pipeline will be dense phase. Currently little is known about dense phase CO_2 fluid behaviour when loss of containment occurs;
- There is little documented data on CO_2 pipeline failures to provide historical probabilities for any risk assessments.

8.3.5 The pipeline has been assumed to be a MAHP for the purposes of pipeline design and routing only.

8.3.6 GECL will, in the future, hold informal discussions with the Local Planning Authority (LPA) about the potential issues surrounding dense phase CO_2, including the implications behind transport. At this stage is it felt that no formal discussions or preparations are necessary as detailed design information for both the pipeline and the route are not available.

8.3.7 When GEC moves from CCR towards carbon capture implementation and the classification of dense phase CO_2 is clearer, all the requirements of the PSR will be followed, including formal discussions with the LPA and the preparation of the appropriate plans.

8.3.8 The transport assessment will be reviewed on an ongoing basis as part of the Status Reports, with a view to incorporating any developments into an updated design for carbon capture at GEC.

SECTION 9

ECONOMIC ASSESSMENT

9 ECONOMIC ASSESSMENT

9.1 Overview

9.1.1 This Section reviews the economic feasibility of incorporating carbon capture technology into GEC. It tests a number of key industry and market sensitivities, and compares outputs with the findings of recent industry reference reports.

9.1.2 Assumptions used in the analysis are consistent with those used in recent reports by PB investigating CCR.

9.2 Guidance

9.2.1 Under the Government's CCR Policy as detailed in the Guidance, developers are required to demonstrate:

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

9.2.2 Additionally, the Directive on the Geological Storage of Carbon Dioxide suggests that:

"*The economic feasibility of the transport and retrofitting should be assessed taking into account the anticipated costs of avoided CO_2 for the particular local conditions in case of retrofitting and the anticipated costs of CO_2 allowances in the Community. The projections should be based on the latest evidence; review of technical options and uncertainty analysis should also be made*".

9.2.3 In terms of a retrofitting economic assessment, the Guidance states that a wide range of assumptions are likely to be involved, including:

- Future input fuel prices (both absolute and relative to other fuels);
- Electricity price levels;
- Rising carbon emissions prices; and
- The capture technology's likely capital and operating costs.

9.2.4 Given the unknowns surrounding CO_2 transport arrangements, the Government accepts that only a high level analysis of transport solutions will be possible. The factors that have been taken into account include:

- Potential technical specifications of any onshore pipeline;
- Experience of the natural gas industry with pipeline routing;
- Appropriate allowances for potential route variations to avoid specific environmentally sensitive sites, or deeper burial or avoidance of certain inhabited areas;
- Existing experience with the costs of offshore pipelines;
- The approximate lengths of the onshore and offshore pipelines; and
- The need for compression booster stations.

9.3 Assessment Methodology

9.3.1 To investigate the economic feasibility of GEC with the addition of carbon capture technology, an economic model has been developed to calculate the lifetime cost of electricity, expressed in terms of £/MWh, over the 35 year lifetime of GEC.

9.3.2 As required by the Guidance the economic feasibility of carbon capture technology and transport infrastructure are modelled in their entirety. The effects of taxation have not been considered in the modelling.

9.3.3 The economic feasibility of GEC was assessed by varying the price of EU Allowances under the EU Emissions Trading Scheme (EU ETS) whilst the remaining parameters remained constant. This allowed for the identification of the price of EU Allowances for CO_2 where GEC with CCS became economic.

9.3.4 The assessment methodology, which accounts for all the economic assessment criteria set out in the Guidance, is as follows:

Step 1. The model is used to calculate the cost of electricity generation (in p/kWh), over the lifetime of GEC, without the addition of carbon capture technology ('no CCS'). This assumes that EU Allowances must be purchased for 100 per cent of the residual CO_2 emitted to atmosphere by GEC. The cost of electricity generation is calculated with carbon prices ranging from €0/tonne to €150/tonne in €25/tonne increments.

Step 2. The model is used to calculate the cost of electricity generation (in p/kWh), over the lifetime of GEC, with the addition of carbon capture technology. Again, this assumes that EU Allowances must be purchased for 100 per cent of the CO_2 emitted to the atmosphere by GEC. The cost of electricity generation is calculated with carbon prices ranging from €0/tonne to €150/tonne in €25/tonne increments.

Step 3. The base case assumptions are then stressed to identify a potential cost range for GEC through the combination of upside and downside scenarios. These include stressing the fuel pricing, the capital costs and the base-line costs for the transportation and storage elements.

Step 4. The range of the electricity generation costs for both the 'no CCS' and 'CCS' cases are then plotted graphically to present the range of carbon prices within which GEC with carbon capture technology is economically feasible with present uncertainties.

9.4 Assumptions

9.4.1 The assumptions made in the economic assessment for the base case modelling are detailed in Table 8.

TABLE 8: ECONOMIC ASSESSMENT BASE CASE ASSUMPTIONS[11]

Variable	***Assumption***
Assumed First Year of Operation	2009*
£:€ Exchange Rate[12]	1.1192
Nominal Discount Rate	10%
Gas Price	46.1 p/therm[13]
Carbon Allocations	None for Power Sector – Full Purchase
Power Output Impact of Carbon Capture, Transportation and Storage :	
Net Power Output of GEC	878 MWe
Net Power Output of GEC with steam extraction for the carbon capture plant	808 MWe
Lifetime load factor of GEC	75%
CO_2 emitted by GEC before Carbon Capture	88 kg/s
CO_2 emitted by GEC after fitting Carbon Capture Technology	9 kg/s

* *2009 has been selected as the first year of operation to remove uncertainty with respect to the capital equipment pricing which may be different in 2015 (the current anticipated first year of commercial operations)*

[11] *Table based on Option A*
[12] *Exchange rate taken on 26 October 2009*
[13] *Source: Average of Central Scenario of "Communication on BERR Fossil Fuel Price Assumptions; Update to present the latest fossil fuel price assumptions following the January 2008 Call for Evidence", BERR, May 2008; escalated to 2009 prices.*

9.5 Scenarios

9.5.1 The model has been run using three scenarios relating to the possible CO_2 transport and storage infrastructure options, outlined below:

a) ***"2009, Dedicated New CO_2 Transport & Storage Assets"***
In this scenario we assume that all of the onshore and offshore infrastructure for carbon capture and storage will be based on new assets. The storage sites targeted are existing gas fields in the SNS Basin. It is assumed that the infrastructure will be sized to the project and would be 'dedicated' to the project.

b) ***"2009, Dedicated New CO_2 Transport assets, Re-use Storage Assets"***
The assumption in this instance is that the storage infrastructure can be re-used but both onshore and offshore pipelines are again new build and sized for the project, i.e 'dedicated'.

c) ***"2020, Shared New CO_2 Transport & Storage Assets"***
Whilst the Guidance states that outsourcing of CO_2 transport and storage cannot be assumed in this feasibility study, we have included such an option for comparative purposes. Given the location of GEC there is a possibility that a shared CO_2 transportation and storage network could be developed to provide a "route-to-store" for the various power plants in the region. To recognise this possibility, the model has been run for a case where the transportation and storage system is shared. As this is only likely to be the case at some point in the future, the modelling is carried out on the basis of the 2020 cost projections[14] (2009 base prices). A number of power plants were considered in this hypothetical shared system (apart from GEC) including Damhead Creek 2, Medway and Grain CCGT. It is assumed the system would comprise of two branches. The first would begin at Damhead Creek 2 and would run along the Medway River. The two stations on the Isle of Grain; Medway and Grain CCGT would then link into the network before running on to the mouth of the Thames. The second branch would begin at GEC. This would traverse the River Thames before linking in with the first branch at some point in the mouth of the River Thames. The pipeline would then run to storage as suggested above. Costs are shared on the basis of CO_2 volumes produced by each scheme on a pro-rata basis.

9.5.2 A number of sensitivities have been run on each of the three scenarios outlined above, to test the sensitivity of the results, listed below:

- **Gas Pricing –**
Volatility in the gas market (assuming continued linkage with oil) in the UK in recent years has shown that there remains significant uncertainty in the longer term forward price. The economic assessment has modelled what is considered to be outlying possibilities for the gas price with a $\pm$30 per cent range.

- **Capital Cost –**
The capital cost for GEC has been stressed with a $\pm$10 per cent uncertainty range. This uncertainty is applied to GEC, the capture plant retrofit costs and the transportation and storage. Additional cases have been modelled to understand the uncertainty relating to the timing of the CCS retrofit and the CO_2 transportation.

- **Discount Rate –**
Whilst a nominal 10 per cent discount rate is considered to be a reasonable value for a base case analysis for a CCGT project, the addition of the CCS

[14] *The retrofit analysis has taken into account the costs associated with retrofitting CCS related to the present status (2009) of the CCS market (i.e., immature at utility scale), and to the future status (2020) of the CCS market (i.e., when it is likely that CCS will be proven at utility scale and economies of scale are beginning to be seen through the supply chain). Note that all costs are quoted on a 2009 base.*

chain as a retrofit at some time in the future is considered to present an additional risk to developers of power plant, and therefore a higher risk adjusted discount rate of 12.5 per cent has been added to reflect this risk.

9.5.3 The scenarios for gas pricing, capital costs and discount factors are summarised in Table 9

TABLE 9: UNCERTAINTY ANALYSIS SCENARIOS

	Gas Price	Capital Costs	Discount Rate
Scenarios:			
Low Gas Price	-30%	As Base Case	10%
High Gas Price	+30%	As Base Case	10%
Low Capital Cost	As Base Case	-10%	10%
High Capital Cost	As Base Case	+10%	10%
High Discount Rate	As Base Case	As Base Case	12.5%

9.6 Economic Assessment

9.6.1 The results of the assessment are shown in Insert 1 and Insert 2

9.6.2 Insert 1 shows the results of the modelling for procurement of GEC and the CCS chain in 2009.

9.6.3 Note that:

- The carbon price (the price of the EUA's, in €/tonne) is shown along the x-axis, the lifetime cost of electricity (in p/kWh) is shown along the y-axis;
- The solid line represents the Base Case scenario, the dotted lines represent the upper and lower limits of the sensitivity runs;
- The sensitivity runs illustrated show the cumulative effect of factors increasing the cost of electricity (high gas price, high capital cost, high discount rate), and of factors decreasing the cost of electricity (low gas price, low capital cost);
- For GEC without the addition of CCS (the black line), for an EUA price of €25/tonne the lifetime cost of electricity is around 5.7p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 9.7p/kWh;
- For GEC with the addition of CCS and new transport and storage assets (the purple line), for an EUA price of €25/tonne the lifetime cost of electricity is around 7.2p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 7.6p/kWh;
- For GEC with the addition of CCS and new transport and re-used storage assets (the red line), for an EUA price of €25/tonne the lifetime cost of electricity is around 8.2p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 8.7p/kWh; and
- For the Base Case, the minimum required price of one EUA under the EU-ETS, such that the cost of electricity over the life of GEC fitted with CCS remains the same value as that for GEC without the addition of CCS, is around €100/tonne.

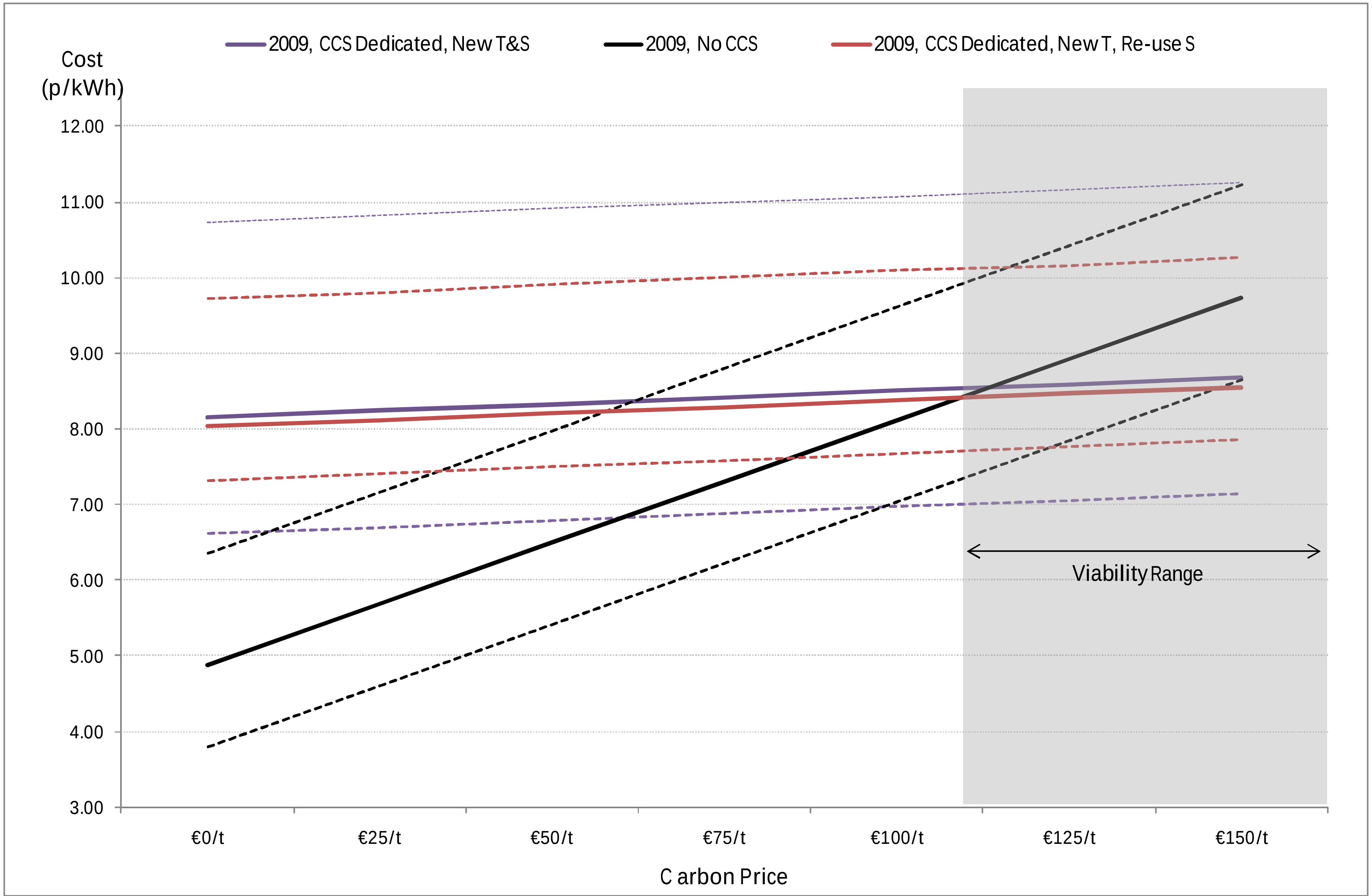
9.6.4 Insert 2 shows the results of the modelling for procurement of GEC in 2009 and the CCS chain using 2020 price projections (in 2009 prices).

9.6.5 Note that:

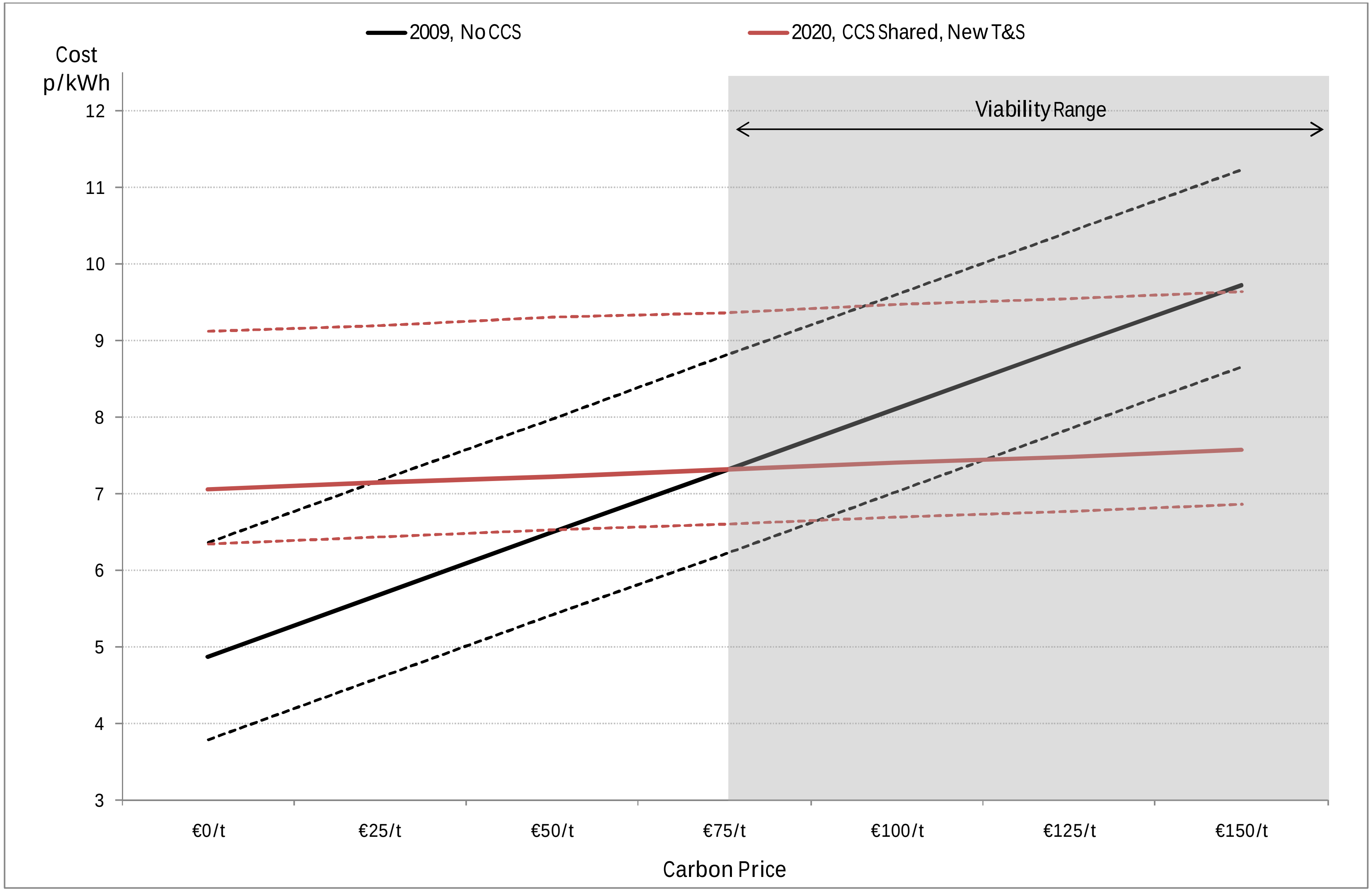
- The carbon price (the price of the EUA's, in €/tonne) is shown along the x-axis, the lifetime cost of electricity (in p/kWh) is shown along the y-axis;
- The solid line represents the Base Case scenario, the dotted lines represent the upper and lower limits of the sensitivity runs;

- For GEC without the addition of CCS (the black line), for an EUA price of €25/tonne the lifetime cost of electricity is around 5.7p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 9.7p/kWh;
- For GEC with the addition of CCS and new shared transport and storage assets (the red line), for an EUA price of €25/tonne the lifetime cost of electricity is around 7.2p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 7.6p/kWh; and
- For the Base Case, the minimum required price of one EUA under the EU-ETS, such that the cost of electricity over the life of GEC fitted with CCS remains the same value as that for GEC without the addition of CCS, using 2020 price projections, is around €75/tonne.

INSERT 1: GEC – CCS FEASIBILITY 2009



INSERT 2: GEC – LIKELY CCS FEASIBILITY 2020



9.7 Conclusions

9.7.1 The results of our modelling show that the retrofitting of carbon capture technology to GEC becomes economic on the basis of EUA prices of €82/tonne, for plant using 2009 prices. Learning effects mean that the break even cost should fall to nearer €62/t on the basis of 2020 costs.

9.7.2 These prices can be readily compared with data from external forecasters, e.g. the independent McKinsey Report "Pathways to a Low Carbon Economy" (2009) and the "Cost Abatement Curve". In particular Exhibit 8.1.4 of the McKinsey Report indicates an abatement cost of 50 Euros per tonne CO_2 for a gas CCS new build (by 2030). Over time, it is anticipated that the 75 Euros per tonne CO_2 may tend toward the order of 50 Euros per tonne (predicted by external forecasters) as knowledge on the carbon capture technology advances. It may also be considered that in the future some form of direct support for carbon capture facilities may be in place, e.g. feed-in tariffs, capital grants, soft loans on favourable terms, etc.

9.7.3 It should be noted that as recently as 2007/08 the wholesale electricity market was in the region of 80 to 90 £/MWh (8 to 9p/kWh). It is therefore considered possible that these pricing levels will become more prevalent as the time for the retirement of power plants approaches in 2015, due to the requirements of the Large Combustion Plant Directive (LCPD) (Directive 2001/80/EC).

9.7.4 Furthermore, the EU ETS Phase III, which starts in 2013, will not provide any free allocation of EUA's to power generators within Europe. Therefore, whilst the full cost of carbon is presently recognised within the wholesale electricity pricing, the impact of the full auctioning for power plants (and the sliding scale cap from the mid point of EU ETS Phase II being applied to the remaining sectors within the EU ETS) means that there is likely to be significant upwards price pressure on EUA's from 2013 onwards. Therefore the high carbon prices required for CCS economic feasibility are considered to be within the present expectations of forward carbon pricing, and thus GEC is likely to be economically feasible within its operating lifetime.

9.7.5 The costs we have used for the economic assessment are based on those for a carbon capture plant procured in 2009. These costs are expected to reduce in time, bearing in mind the recent and likely future developments in technology.

SECTION 10

REQUIREMENT FOR HAZARDOUS SUBSTANCES CONSENT

10 REQUIREMENT FOR HAZARDOUS SUBSTANCES CONSENT

10.1 Guidance

10.1.1 The Guidance states that

"*Operational CCS is likely to bring onto combustion plant sites chemicals and gases which are not currently present (or not present in such quantities) on such sites. Depending on the hazard classification of these substances and the quantity present, sites with operational CCS could become subject to the Council Directive 96/82/EC known as the Seveso II Directive. This Directive is implemented in the UK by the Control of Major Accident Hazards (COMAH) Regulations 1999 and their update (Control of Major Accident Hazards (COMAH) Regulations 2005), and the Planning (Control of Major Accident Hazards) Regulations 1999*".

10.1.2 In addition, the Guidance states that "*one of the consequences of operating sites at which such substances are present is the need to obtain Hazardous Substances Consent (HSC)".*

10.1.3 Therefore, if a developer's CCR proposals for operational CCS involve the storage or use on site of hazardous substances currently classified under the above Regulations, it may be necessary to apply for HSC at the same time as applying for the initial Consent.

10.2 Evaluation of the Potential Requirement for HSC at GEC

10.2.1 Risk assessment and reduction activities will need to be conducted which focus not only on the carbon capture technologies, but also on the associated interconnections / integration points with the power generation facility.

10.2.2 As a result, mitigation measures will need to be developed to reflect any risks associated with both the chemical capture process and the captured CO_2 as required by the Regulations.

Carbon Capture Solvent – Monoethanolamine (MEA)

10.2.3 As discussed in Section 4.1, the feasibility of CCR for GEC has been assessed on the basis of post-combustion capture via chemical absorption using an amine solvent. The named amine solvent is MEA.

10.2.4 MEA is a chemical which is not normally present on combustion plant sites, and as such would be subject to requirements under both the COMAH Regulations and Planning (COMAH) Regulations if its classification fell within their scope.

10.2.5 The MEA that would be present on site would either be stored as a pure substance, or be used in the capture process as a solution. These are respectively referred to as MEA Substance and MEA Preparation.

10.2.6 In terms of the MEA Substance, the current classifications are Xn R20/21/22 and C R34. These translate into 'harmful' and 'corrosive' classifications.

10.2.7 In terms of the MEA Preparation, a solution of $\geq$ 25 per cent MEA would have the same classifications as MEA Substance.

10.2.8 Both in terms of the MEA Substance and the MEA Preparation, the current classifications are such that a HSC is not required for the carbon capture plant at GEC under the scope of either the COMAH Regulations or the Planning (COMAH) Regulations.

10.2.9 In addition, discussions have been held between PB and DECC's Carbon Capture Readiness Team on the risks associated with MEA. In these discussions, DECC has confirmed that, at present, the Health and Safety Executive (HSE) does not consider

MEA to be subject to any requirement for a HSC or be subject to any on-site storage volume limits.

10.2.10 In terms of the emissions / effluents from the carbon capture process it is also not anticipated at this stage that it will be subject to any requirement for a HSC or be subject to any on-site storage volume limits. However, appropriate disposal routes will be used to prevent any build-up of effluents on site.

10.2.11 Further to this, the water produced by the cooling of the flue gases in the carbon capture plant (discussed previously in Section 6) will vary with ambient conditions but is not likely to exceed 120 t/h, depending on the gas turbine selection. This water will be of reasonable quality, but will be acidic due to the presence of NO_2 CO_2 and SO_2 (as well as other micro-constituents) in the flue gases. It is envisaged that this water will be neutralised by dosing on the carbon capture plant and routed to either an LG Development effluent system and / or polished at the water treatment facility on the GEC site and used / exported as demineralised water.

10.2.12 Therefore, on the assumption of post-combustion capture based on chemical absorption using MEA at the carbon capture plant at GEC, current knowledge of the MEA used in the capture process and of the effluent which is produced is such that, at this stage, a HSC is not required.

Captured CO_2

10.2.13 As the Guidance states, it may be likely that dense phase CO_2 would be present on site once the captured CO_2 is compressed in preparation for transport. Whilst dense phase CO_2 is not currently classified as hazardous, it is now recognised that an accidental release of large quantities of CO_2 could result in a major accident.

10.2.14 At present there is extensive ongoing research into the hazard potential of dense phase CO_2 and the results of this work will inform future decisions on CO_2 and whether the current classification should be reviewed.

10.2.15 As a result, the Guidance suggests that if it is envisaged for any dense phase CO_2 to be on site, the principles of the COMAH Regulations should be applied by early adopters of the actual CCS process when designing, constructing and operating their capture and compression equipment.

10.2.16 This is most likely to impact on DECC's current CCS Competition which will likely see combustion plant sites implement the full CCS chain whilst the regulatory framework surrounding dense phase CO_2 remains uncertain.

10.2.17 Dense phase CO_2 may be present on site at the carbon capture site boundary after compression in preparation for immediate transport by pipeline.

10.2.18 Whilst pipelines fall outside the scope of the COMAH Regulations, the on site pipeline would be subject to the Planning (COMAH) Regulations if dense phase CO_2 were to receive a classification which made it fall within the scope of these Regulations. However, until the classification is known and the information on the controlled quantity is available, it is not known whether the Planning (COMAH) Regulations would apply.

10.2.19 GECL will be holding informal discussions with the LPA about the potential issues surrounding dense phase CO_2, including the implications behind the possible presence of small amounts on site within the compression equipment. These informal discussions will continue until further information concerning the classification of dense phase CO_2 is available. This will ensure that there is early identification of any potential implications on the LPA's long term plan for the area.

10.2.20 In terms of transport to storage areas, discussion of dense phase CO_2 in pipelines is provided in Section 8.2.

10.2.21 On the basis of the carbon capture technology selected for GEC (post-combustion capture based on MEA) and the current classifications of the chemicals / substances which are likely to be on site, it is concluded that a HSC is not required for GEC at this stage.

10.2.22 If a HSC is required when GEC's CCR Status is converted to CCS, an application would be made at this stage. This is because any detailed information which would be required for the HSC Application will not be known until this stage, and the final process is selected and the detailed design takes place.

10.2.23 The two yearly Status Reports, required under the CCR Policy, will provide an opportunity for reassessment / review of any of the above requirements and options, particularly regarding any developments in classifications / carbon capture technologies.

SECTION 11

CONCLUSIONS

11 CONCLUSIONS

11.1 Overview

11.1.1 This CCR Feasibility Study has been undertaken by PB on behalf of GECL to support the Consent application for GEC.

11.1.2 GEC will be located on land within the London Gateway Port / London Gateway Logistics and Business Park development, collectively called the LG Development. The LG Development, promoted by DP World, is currently in the early stages of construction.

11.1.3 The EU agreed the text of a new EU 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 and the Directive came into force on 25 June 2009.

11.1.4 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 MWe or more (and for which the construction / operating license was granted after the date of the Directive) will carry out a CCR Feasibility Study.

11.1.5 As part of the CCR Feasibility Study, the Guidance (associated with the CCS Directive) states that Consent applicants will be required to demonstrate:

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

11.1.6 Further to this: "*if Applicant's proposals for operational CCS involves the use of hazardous substances, they may be required to apply for Hazardous Substances Consent (HSC). In such circumstances they should do so at the same time as they apply for Section 36 Consent*".

11.1.7 On the basis of the carbon capture technology selected for GEC (post-combustion capture based on MEA) and the current classifications of the chemicals / substances which are likely to be on site, it is concluded that a HSC is not required for GEC at this stage.

11.1.8 If a HSC is required when GEC's CCR Status is converted to CCS, an application would be made at this stage. This is because any detailed information which would be required for the HSC Application will not be known until this stage, and the final process is selected and the detailed design takes place.

11.1.9 This CCR Feasibility Study presents the results of the required assessments for GEC. Accordingly, this CCR Feasibility Study has demonstrated:

- The availability of suitable storage sites;
- The technical feasibility of transport facilities;
- The technical feasibility of retrofit;
- The economic feasibility of transport facilities and retrofit; and,

- Establishes that there is suitable space for CCS equipment at the GEC site.

11.1.10 In respect of the economic feasibility for transport facilities and retrofit, it is considered that these are expected to become economically feasible at some point in the future given:

1. The recent and likely future developments in CCS technology, much of which will stem from the proposed CCS Demonstration Competition to be funded by DECC and the EU;
2. The likely long-term movements in the price of carbon;
3. The proposed treatment in Phase III of the EU ETS of carbon which is emitted, captured and stored; and, in particular,
4. The UK Government's stated commitment to establishing the necessary Economic and Regulatory Framework for CCS.

11.1.11 It is considered that these assessments have demonstrated that it could be both technically and economically feasible to retrofit carbon capture and storage technology to GEC within its 35 year operating lifetime.

APPENDIX A

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

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

Annex

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

Article 32
Amendment of Directive 2001/80/EC

In Directive 2001/80/EC, the following Article 9a is inserted:

"Article 9a

1. Member States shall ensure that operators of all combustion plants with [...] a rated electrical output of 300 megawatts or more for which the original construction license or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive XX/XX/EC of the European Parliament and of the Council(*), have assessed whether the following conditions are met:
   - suitable storage sites are available;
   - transport facilities are technically and economically feasible;
   - it is technically and economically feasible to retrofit for CO2 capture.

2. If the conditions in paragraph 1 are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress CO2 [...] is set aside. The competent authority shall determine whether the conditions are met on the basis of the assessment referred to in paragraph 1 and other available information, particularly concerning the protection of the environment and human health.]

(*) OJ L…, …, p. ..".
300MW provision......

APPENDIX B

ANNEX C OF THE CONSULTATION “CARBON CAPTURE READINESS (CCR) A GUIDANCE NOTE FOR SECTION 36 ELECTRICITY ACT 1989 CONSENT APPLICATIONS” (NOVEMBER 2009)

Annex C

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

Capture Ready Features

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

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

Post-combustion (amine scrubbing)

C1 Design, Planning Permissions and Approvals

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

C2 Power Plant Location

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

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

C3 Space Requirements

Space will be required for the following:

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

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

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

C4 Gas Turbine Operation with Increased Exhaust Pressure

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

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

C5 Flue Gas System

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

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

C6 Steam Cycle

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

C7 Cooling Water System

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

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

C8 Compressed Air System

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

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

C9 Raw Water Pre-treatment Plant

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

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

C10 Demineralisation I Desalination Plant

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

C11 Waste Water Treatment Plant

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

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

C12 Electrical

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

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

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

C13 Plant Pipe Racks

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

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

C14 Control and Instrumentation

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

C15 Plant Infrastructure

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

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

Other technologies for post-combustion capture

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

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

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

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

APPENDIX C

CCR REQUIREMENTS CHECKLIST BASED ON “CARBON CAPTURE READINESS (CCR) A GUIDANCE NOTE FOR SECTION 36 ELECTRICITY ACT 1989 CONSENT APPLICATIONS” (NOVEMBER 2009)

Guidance Paragraph	*Requirement for CCR Assessment*	*CCR Feasibility Study Reference / Additional Comment*
6	Applicant must demonstrate that there are no known technical or economic barriers which would prevent the installation and operation of its chosen CCS technologies.	See Section 6 (Technical Assessment – Retrofitting and Integration of CCS) and Section 9 (Economic Assessment).
7	Applicant needs to demonstrate: - That sufficient space is available on or near to the site to accommodate carbon capture equipment in the future - The technical feasibility of retrofitting its chosen carbon capture technology - That a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from GEC - The technical feasibility of transporting the captured CO_2 to the proposed storage area;. - The likelihood that it will be economically feasible within GEC's lifetime to link it to a full CCS chain covering retrofitting of capture equipment, transport and storage	- See Section 5 (Technical Assessment – CCS Space Requirements) - See Section 6 (Technical Assessment – Retrofitting and Integration of CCS) - See Section 7 (Technical Assessment – CO_2 Storage Areas) - See Section 8 (Technical Assessment – Transport) - See Section 9 (Economic Assessment)
7	Applicant must make clear in its CCR assessment which CCS retrofit, transport and storage technology options are considered the most suitable for the proposed development.	See Section 6 (Technical Assessment – Retrofitting and Integration of CCS), Section 8 (Technical Assessment – Transport) and Section 7 (Technical Assessment – CO_2 Storage Areas)
11, 18 and 19	Applicant should be prepared to submit plans and supporting docs with initial Section 36 Consent application to demonstrate that sufficient space is available to accommodate carbon capture equipment, sized so as to be capable of processing emissions from the entire GEC in future. Site plans should show: - the footprint of the combustion plant - the location of the capture plant inc. air separation units - the location of the CO_2 compression equipment - the location of any chemical storage facilities - the exit point for CO_2 pipelines from the	See Section 5 (Technical Assessment – CCS Space Requirements) and Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre) respectively.

	site. Conceptual diagrams and a description of how space will be used should be submitted. Basic calculations using known CO_2 volumes could usefully be included in the space description to justify size/type of processing equipment chosen.	
11	Applicant should explain percentage of CO_2 emissions it considers will be captured by proposed capture technology. The detail required will need to be such that Secretary of State for DECC is confident that the applicant is allowing sufficient space on site and in appropriate areas on site for subsequent retrofit.	See Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre).
13	Applicant should make reasoned justification for its proposed space allocation on the basis of its chosen capture technology.	See Section 5 (Technical Assessment – CCS Space Requirements) and Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre).
15	Applicant must be able to demonstrate suitably located land will be available to it to use for the capture element of the CCS chain at the point of retrofit. If it does not already own or occupy the ancillary site, the applicant will need to satisfy Secretary of State for DECC that it is in a position to ensure that it will be able to use the ancillary site when it moves to installing CCS.	See Section 5 (Technical Assessment – CCS Space Requirements).
20	Applicant should explain what percentage of CO_2 emissions it considers will be captured by its proposed technology. Applicant must include a clear statement on what type of technology is considered most appropriate for its power station. Applicants can discuss other options, but must make clear the option which is considered most appropriate. This technology will be the one assessed in the economic assessment.	See Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre) and Section 4 (Proposed Capture Plant Technology).
21	Applicant should provide an assessment of its proposed plant designs as part of Section 36 Consent application so that EA is able to advise Secretary of State for DECC that there are no known technical barriers to a subsequent retrofit of the type of capture technology declared.	See Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre), Section 4 (Proposed Capture Plant Technology), Section 5 (Technical Assessment – CCS Space Requirements), Section 6 (Technical Assessment – Retrofitting and Integration of CCS), Section 7 (Technical Assessment – CO_2 Storage

		Areas) and Section 8 (Technical Assessment – Transport).
27	Applicant is asked to demonstrate that there are no known technical or economic barriers which would prevent the installation and operation of its chosen technology. Applicant must follow best practice as far as this knowledge is available and provide a reasoned justification of its choice.	See Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre), Section 4 (Proposed Capture Plant Technology), Section 5 (Technical Assessment – CCS Space Requirements), Section 6 (Technical Assessment – Retrofitting and Integration of CCS), Section 7 (Technical Assessment – CO_2 Storage Areas), Section 8 (Technical Assessment – Transport) and Section 9 (Economic Assessment).
28	Requirements specific to post-combustion capture.	See Section 4 (Proposed Capture Plant Technology), and Section 6 (Technical Assessment – Retrofitting and Integration of CCS).
29	Applicant is only asked to compare efficiencies of its power station once capture is operational rather than before	See Section 6 (Technical Assessment – Retrofitting and Integration of CCS).
32	Applicant is responsible for making a short, reasoned, written justification of its proposed storage area, demonstrating that no known barriers exist to its use for CO_2 sequestration.	See Section 7 (Technical Assessment – CO_2 Storage Areas)
33 and 42	Applicants must identify an offshore CO_2 storage area in its CCR storage assessment. The geographical extent of the area should be delineated.	See Section 7 (Technical Assessment – CO_2 Storage Areas)
34	Applicants are advised to identify within the delineated area (on a map) at least two fields or saline aquifers listed in either the “valid/viable” or “realistic” categories of the 2006 DTI Study. If other data source is used although will need to demonstrate equivalent levels of certainty.	See Section 7 (Technical Assessment – CO_2 Storage Areas)
39 and 42	Applicant should include a short summary including an estimate of the total volume of CO_2 that would be produced captured and stored as part of its CCR storage assessment. Assessment should include an estimate of the CO_2 storage potential of the area identified.	See Section 3.3 (Estimation of Size of Carbon Capture Chain for Gateway Energy Centre) and Section 7 (Technical Assessment – CO_2 Storage Areas)
44 and 60	Applicant must demonstrate that a feasible route exists from site to storage area.	See Section 8 (Technical Assessment

	Applicants are asked to identify a favoured route for their pipeline within a 1 km corridor within a 10 km radius of the power station. Applicant should identify major pre-existing obstacles arising because of safety of environmental concerns. Applicant should suggest methods by which the environmental impacts on an unavoidable designated site within the route corridor could be mitigated on the basis of current knowledge A map should be marked up at a scale sufficiently large for the proposed route corridors to be clear.	– Transport)
46	After first 10 km from the power station, Applicant is asked to identify a 10 km wide corridor to the point on the coast where it envisages a pipeline going offshore or CO_2 going onboard a ship.	See Section 8 (Technical Assessment – Transport)
48	If pipeline options are limited, unavoidably impinge on a designated site etc, applicant should suggest how such impacts could be minimised.	There are considered to be no barriers in this regard to the eventual implementation of carbon capture at GEC.
52	Applicant will need to demonstrate in its assessment that a feasible route from land to sea exists. Applicants should acknowledge potential barriers to the transport of CO_2 offshore and suggest how these factors might be mitigated.	See Section 8 (Technical Assessment – Transport)
54 and 60	Applicant's assessment should contain a similar degree of detail for the offshore pipeline with the rest of the onshore route. Only broad corridors need be identified. Applicant should demonstrate that there are no barriers to the transport of CO_2 by the declared preferred method into any of the fields/aquifers in the storage area. Applicant should confirm that no unavoidable safety obstacles exist within the identified route corridor, on the basis of current knowledge about the hazards posed by CO_2 transport.	See Section 8 (Technical Assessment – Transport)
60	Requirements if applicant proposes to move CO_2 by ship	At present it is not proposed to move CO_2 by ship. However this will be reviewed on an ongoing bases as part of the Status Report, with a view to incorporating any developments into an updated design for carbon capture at

		GEC.
64	Applicant should conduct a single economic assessment which encompasses retrofitting of capture equipment, CO_2 transport and the storage of CO_2. Applicants should demonstrate the full range of costs and benefits associated with the deployment of CCS to any given plant in a manner which takes full account of all relevant technical and economic factors and is not inconsistent with EU Directive 2009/31/EC.	See Section 9 (Economic Assessment)
65	Applicant should provide evidence of reasonable scenarios, taking into account cost of capture technology and transport option chosen and the estimated cost of CO_2 storage which make operational CCS economically feasible for the proposed development.	See Section 9 (Economic Assessment)
68	Sets out model assessment structure	See Section 9 (Economic Assessment)