Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

Title: Strategic UK CO2 Storage Appraisal Project – Addendum

Abstract:

The objective of the project is to provide insights into four specific areas highlighted as having potential to reduce costs and or risk for CCS. This report and associated appendices summarises the results of that work and provides some additional options for future developers of CO2 storage sites to consider.

Context:

This project, funded with up to £2.5m from the UK Department of Energy and Climate Change (DECC - now the Department of Business, Energy and Industrial Strategy), was led by Aberdeen-based consultancy Pale Blue Dot Energy supported by Axis Well Technology and Costain. The project appraised five selected CO2 storage sites towards readiness for Final Investment Decisions. The sites were selected from a short-list of 20 (drawn from a long-list of 579 potential sites), representing the tip of a very large strategic national CO2 storage resource potential (estimated as 78,000 million tonnes). The sites were selected based on their potential to mobilise commercial-scale carbon, capture and storage projects for the UK. Outline development plans and budgets were prepared, confirming no major technical hurdles to storing industrial scale CO2 offshore in the UK with sites able to service both mainland Europe and the UK. The project built on data from CO2 Stored - the UK's CO2 storage atlas - a database which was created from the ETI's UK Storage Appraisal Project. This is now publically available and being further developed by The Crown Estate and the British Geological Survey. Information on CO2Stored is available at www.co2stored.com.

2016

D17: WP8 - Strategic UK CO2 Storage Appraisal

Project – Addendum

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1.0 Executive Summary

Four pieces of work have been completed which address key issues identified during the SSAP work.

Options to develop depleted gas fields without heating are identified and assessed.

SSAP costing methodology is validated with the CCS Commercialisation Programme outputs.

Minimum Viable Development options have been identified for each site.

Motivations for storage clusters are defined and used to outline potential cluster developments in UK waters.

This Energy Technologies Institute (ETI) project has been commissioned as an adjunct to the Strategic UK CCS Storage Appraisal Project (SSAP) that was completed in May 2016.

The objective of the current project is to provide additional insight into four specific areas highlighted in the original project as having potential to reduce costs and or risk. This report and associated appendices summarises the results of that work and provides some additional options for future developers of CO_2 storage sites to consider.

Typically, the operating philosophy for CO_2 injection into depleted gas fields requires the CO_2 to be transported offshore in liquid phase and then heated so that it can be injected in gas phase until the reservoir pressure has increased sufficiently that CO_2 can be injected in liquid phase. This philosophy is to manage the low temperature risks and ensure single phase conditions in the wells. For the Hamilton field, 10MW of heating were estimated to be required to inject 5MT/y of CO_2 during the initial 7-year operating phase, adding £128m (15%) to the life-cycle cost.

This current project identified five options to develop the Hamilton depleted gas-field without heating. The most promising was to restrict the development to gas phase operations which in turn limits the amount of CO_2 that can be injected to approximately 14 MT (11% of previous 125MT inventory). This approach is unlikely to be economically attractive but might prove an initial stage to a phased development of the site by deferring expenditure on heating until a later date.

The final report of SSAP was prepared in April 2016 and included an assessment of the development costs for CO_2 storage at the Goldeneye and

Endurance sites. Shortly after this time DECC published high level cost estimates for these two sites as part of the Key Knowledge Deliverables (KKD) from the CCS Commercialisation Programme.

This current project completed a like-for-like comparison of development costs for each of the sites and concluded that although differences exist, overall the estimates were in agreement and the absence of detail in the KKD means that it is not possible to fully understand the reasons for similarities or difference between the estimates.

A major part of the SSAP work was to design and prepare detailed CO_2 Storage Development Plans for five sites to accommodate a defined CO_2 supply profile. Storage capacity is highly dependent on the way in which a particular store is developed and the SSAP plans were optimised to exploit the available subsurface space as efficiently as possible.

The current work sought to identify and describe a minimum viable development (MVD) scenario for each of these five sites, together with the three sites evaluated under various DECC programmes, collectively the anchor sites. These MVDs essentially provide alternatives to phase developments such that the initial phase is less costly, whilst retaining the optionality for a fuller development at a later stage.

The SSAP work included various scenarios describing how CO_2 storage might be rolled out across the UK and territorial waters. However, it did not specifically investigate options for cluster developments of CO_2 storage sites.

This current project has identified and assessed the cluster options and potential motivations around each of the eight anchor sites studied in SSAP (the 5 studied and the 3 sites evaluated through the CCS Demonstration programme) to outline a cluster development scenario for each anchor site. The most likely driver for clustering is risk mitigation. Three aspects are identified.

- Low capacity or storage efficiency. The anchor site is too small or its storage efficiency is very low such that large step outs are required such as outlined with the Forties 5 Site 1 development.
- Site underperformance. The anchor site underperforms and cluster sites are developed to manage or mitigate risk.
- EOR ready. The cluster is specifically designed such that injection into a storage site can be halted when CO_2 is required by an adjacent oilfield for enhanced oil recovery.

Several suggestions for further work are identified. These primarily relate to developing depleted gas fields or clustering. In particular;

Few, if any, tools exist to confidently model the behaviour of two phase CO_2 flow and development of such tools could be an important step in being able to develop depleted gas fields economically.

Investigation into the consequences of two phase CO_2 flow in wellbores and an objective risk analysis of the potential impacts.

Storage clusters will be required in sites where storage efficiencies are low such as in open saline aquifers. Here more work is required around optimising storage efficiency through reservoir development as this will control the timing and requirement of cluster developments from these sites.

With so much discussion in CCS centred around the benefits of clustering, some outreach work is required to clarify the role and challenges of clusters for offshore storage.

2.0 T1 - Storage Without Heating

2.1 Background

The Strategic UK Storage Appraisal Project (SSAP) appraised the Hamilton site as a possible store for Carbon Dioxide (CO_2). The depleted gas reservoir in the East Irish Sea was identified as a strategic development in terms of its locality, injectivity, storage capacity, and its reservoir characteristics. However, due to its low initial pressure conditions in the depleted gas reservoir, a solution which required offshore heating was proposed. This enabled the site to achieve the 5 Mtpa CO_2 supply requirement and maximise the storage capacity, but there was a CAPEX and OPEX impact associated with the provision of the heating.

The operating philosophy for the CO_2 injection changes as the reservoir pressure increases is as follows:

1. Gas Phase

At the initial reservoir pressure CO_2 can be injected in gas phase both in the pipeline and the wellbore. Under these conditions heating is not required as no CO_2 phase change occurs within the pipeline or wellbore systems with the resulting low temperatures this phase change causes. The CO_2 can operate in the pipeline in gas phase at up to 40 barg at ambient seabed conditions.

2. Transition Phase

As reservoir pressure increases the pressure required to inject the CO_2 into the reservoir increases such that the pressure required in the pipeline exceeds 40 barg. At this stage the pipeline must switch to liquid phase operation. Typically, the CO_2 will be cooled prior to entering the pipeline to around 25^oC and at this temperature the CO_2 pressure must be kept above 62 barg to ensure the CO_2 remains in liquid phase. As the wellhead injection pressure is still well below 62 barg, heating is required to prevent low temperatures and two phase CO_2 flow profile in the wellbore. Assuming the CO_2 has cooled to seabed ambient conditions of 6^oC at the wellhead choke the CO_2 must be heated to above the critical temperature of 31^oC prior to injection into the wellbore to ensure single phase CO_2 in the injector wellbore. The transition period of injection requires the highest heating duty typically 10MW for 5Mtpa of CO_2. The heating duty would decline gradually as the reservoir pressure rises, and pressure drop across the choke declines.

3. Dense Phase

As the reservoir pressure increases further, the wellhead injection pressure will exceed the critical pressure of CO_2 at 72 barg. At this point both the wellbore and pipeline would operate in dense phase. Heating is now only required during restarts when the wellhead pressure would fall below the critical pressure due to the hydrostatic head of CO_2 (typically around 40 barg). The heating duty during restarts would only be around 10% of peak heating demand at around 1 MW, and for a short duration until the wellhead injection pressure increases above the critical pressure of 72 barg.

2.2 Potential Non- Heating CO_2 Injection Options

The following development options have been considered which potentially could inject the CO_2 without heating:

- Gaseous CO_2 phase only
- Onshore heating with insulated offshore pipeline

- Offshore warming spool
- Modification of phase envelope using Natural Gas (Methane) or Nitrogen
- Two-phase CO_2 operation of pipeline and wells

Each of these methods have been considered to determine feasibility, and any injection constraints. The detailed technical report completed by Costain is attached in Appendix 1.

2.2.1 Gaseous Phase Transport and Injection

CO_2 can be injected in gas phase conditions only until the volume injected into the reservoir results in phase change occurring in the pipeline and well tubing. Figure 2-1 shows how the reservoir bottom hole pressure (BHP) changes with the CO_2 volume injected. The injection rate assumes two wells each injecting 2.5 Mtpa. The dashed green horizontal lines in the above chart represent the vapour-liquid equilibrium (VLE) pressure at the minimum ambient sea-bed temperature, 6 °C (light green) and at the critical temperature of CO_2, ~31 °C (dark green), above which the CO_2 will only operate in single (dense) phase.

At seabed temperature, the bottom hole pressure exceeds the saturation pressure at 6°C at approximately 6 – 7 million tonnes of CO_2 per well, or circa 12 – 14 million tonnes of total CO_2 injected. This compares to the capacity of Hamilton using heating of 125 million tonnes.

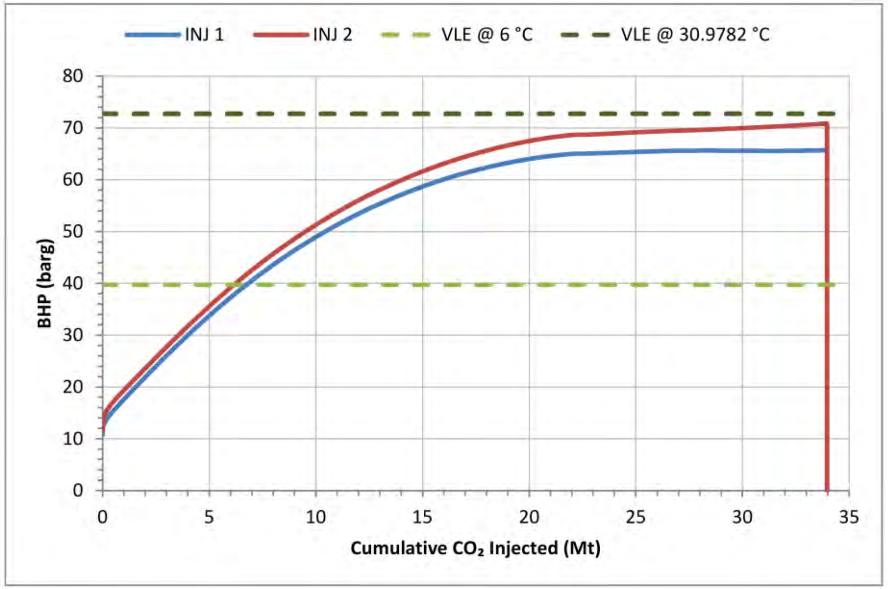

Figure 2-1 Hamilton Reservoir Pressure with Cumulative CO_2 Injection

Modelling has been completed to determine the CO_2 injection flow rate in gaseous phase only through:

- The existing 43.7km 20” pipeline
- A new direct 26km 16” pipeline to Hamilton

The existing pipeline route from Hamilton to the terminal at Point of Ayr is via the Douglas platform to the Southwest of Hamilton. The proposed new pipeline route is a more direct route between Point of Ayr and Hamilton.

The limiting factor in these cases is avoidance of a phase change / two-phase flow in the subsea pipeline. To achieve this, the maximum pressure for the subsea flowline is limited to 40 barg. The results of the modelling are shown in

Figure 2-2. The basis for the pressure drop constraint was the minimum injection wellhead pressure of 35 barg calculated during the SSAP study for a flowrate per injection well of 2.5 Mtpa, assuming a 9 5/8” tubing during gas phase injection. The 3.5 bar pressure drop limit for the pipeline allows around a 1.5 bar margin over the 6 bar allowable pressure drop to keep below the CO_2 dew point limit of 40 barg at the Point of Ayr pipeline inlet.

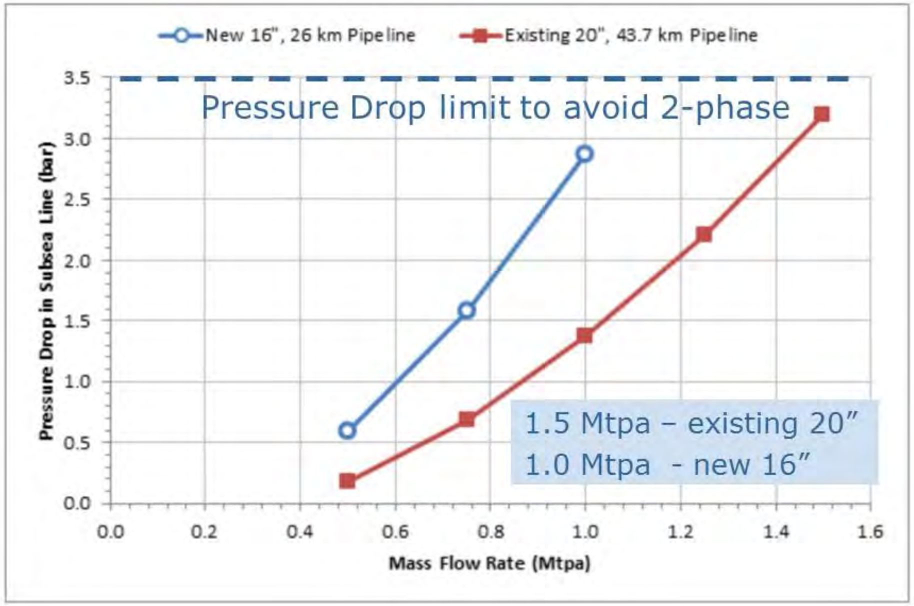

Figure 2-2 Gaseous CO_2 Capacity and New Pipelines

With an initial bottom hole reservoir pressure of 10 barg and a limit of 40 barg as shown in Figure 2-1 the equivalent wellhead pressure has been calculated at flowrates varying from zero to 2.5 Mtpa. The results are shown in Table 2-1. At zero flowrate the wellhead pressure is below the bottom hole pressure due to the hydrostatic head of the CO_2 column. As the reservoir pressure increases the hydrostatic head also increases with density, so at 40 barg reservoir pressure the wellhead pressure would be only 33.7 barg.

The results show that the wellhead pressure remains below the 35 barg wellhead limit (to prevent pipeline two phase flow) at flowrates of up to 0.5 Mtpa per well or a total of 1 Mtpa. At initial bottom hole pressures the wells could each handle up to 2.5 Mtpa without exceeding the 35 barg wellhead limit. This would decline gradually as the reservoir pressure increases.

Injection Well Flowrate Mtpa	Bottom Hole Pressure bara	Wellhead Pressure bara
0	10	8.42
0.5	10	15.4
1	10	20.5
2.5	10	32.1
0	40	33.7
0.5	40	35.8
1	40	37.9
2.5	40	43.7

Table 2-1 Predicted Wellhead Pressure versus Bottom Hole Pressure and Flowrate

Figure 2-2 shows the capacity of the existing 43km 20” pipeline would be around 1.5 Mtpa and a new direct 26km 16” pipeline 1.0 Mtpa. With a reservoir capacity of 12 to 14 million tonnes before switch to dense phase in the reservoir this would provide around 10 to 15 years of CO_2 injection at these reduced rates.

Flow modelling was also completed to determine the pipeline size required to meet the SSAP CO_2 injection requirement of 5 Mtpa. Figure 2-3 shows a new direct 26km 28” pipeline is required to flow 5Mtpa within the pressure drop constraints of the system. This compares to only 1.5 Mtpa for the existing 20” pipeline. It is important to note that less than 2 years of injection would be possible at 5Mtpa before the wellhead pressure constraint of 35 barg was reached for gaseous only flow. The existing 20” pipeline could be used in parallel with a new pipeline. This would marginally reduce the size required for the new pipeline to a 24” pipeline (by interpolation from the existing 20” capacity of 1.5 Mtpa and 22” new direct pipeline capacity of 2.5 Mtpa – see Figure 2-3).

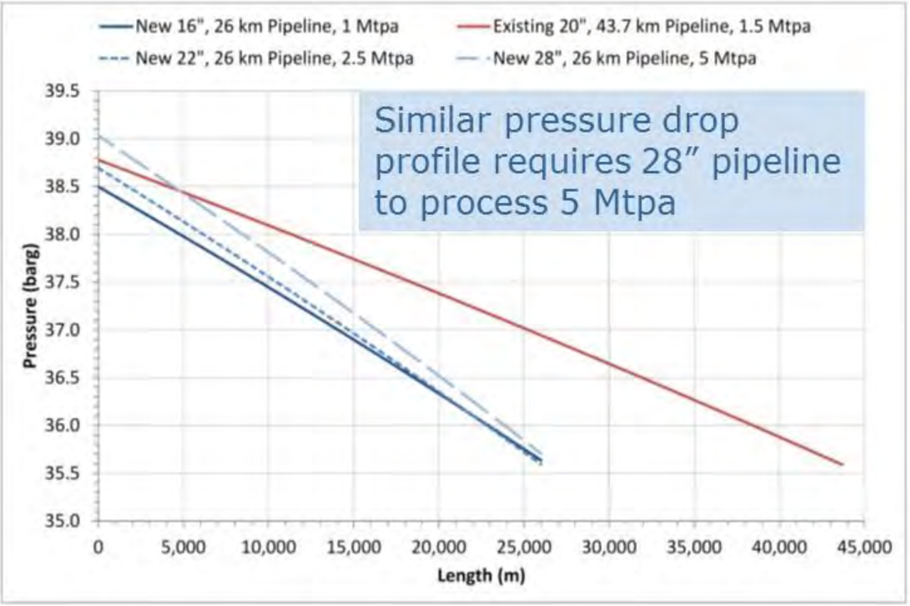

Figure 2-3 New Pipeline Size Required to Inject 5Mtpa in Gaseous Phase

2.2.2 Pipe in pipe Insulated pipeline

An alternative to providing offshore heating, and the associated costs of providing a heat source offshore, is to heat the CO_2 onshore, or use the free heat of compression of the CO_2 at source. The pipeline would be thermally insulating to keep the CO_2 warm. A common technique is to use a pipe-in-pipe (P-i-P) solution, which consists of an inner pipe, or “flowline”, through which the fluid flows, and an outer pipe, or “carrier”, which provides mechanical protection from the subsea environment. Encased between the flowline and the carrier is the thermal insulation of very low thermal conductivity, such as an Aerogel. This enables very low overall heat transfer coefficients (U values) to be achieved.

Modelling was completed to determine the inlet conditions required to achieve an arrival temperature of 30 °C and pressure of 35 barg. A new 26 km, 16 inch NB, pipe-in-pipe flowline, with an overall heat transfer coefficient (U value) of 1 W/m²K was assumed. These arrival conditions would prevent two-phase flow as the CO_2 is above the critical temperature. If the temperature of the CO_2 is kept above the critical temperature no phase change will occur both in pipeline or wellbore regardless of operating pressure. Modelling results showed the following inlet conditions would be required:

Pressure = 93.7 barg

Temperature = 87.2 °C

The system is shown in Figure 2-4.

Figure 2-4 New Insulated Pipeline Operatinf Conditions to Avoid Offshore Heating

The heat capacity of gas is relatively low and therefore, even with highly efficient insulation, the inlet temperature at the onshore terminal (Point of Ayr) is high resulting in pipeline mechanical design issues. Typically, most long distance pipelines do not exceed 30°C inlet design temperature.

During shutdowns however, the CO_2 temperature would cool to ambient conditions, making restarts problematic unless heating was available offshore. It may be possible to operate the wells in two-phase flow for a short duration, until the pipeline warms, but this would require thorough analysis and testing. The alternative would be to vent the CO_2 offshore until the warm CO_2 reaches the platform and injection can then commence. The internal volume of the pipeline is around 600 tonnes of CO_2 which would need to be vented each time the injection pipeline shutdown for significant duration. The option is therefore feasible but substantial operational and design issues exist.

An alternative option is to install dual pipe in pipe insulated pipelines which facilitate circulation of the CO_2 to keep it warm during shutdowns. Heating would be required onshore during shutdowns, either from re-compression, or electric heaters. This would substantially increase the project CAPEX but could potentially reduce offshore OPEX. The existing Hamilton 20” pipeline could not be used for recirculation as the design pressure is too low and it is uninsulated.

2.2.3 Offshore Warming Spool

An offshore warming spool uses ambient sea temperature to warm the CO_2 to minimise low temperatures downstream of the choke. The CO_2 would pass through a choke remote from the wellhead and then flow through a finned tube pipe or coil which would allow the sea to warm the CO_2 prior to injection. The scheme works on the same principal as a water source heat pump.

The system has the advantage of allowing the pipeline to operate in liquid phase thereby avoiding two-phase pipeline operation and increasing pipeline capacity during the gas phase injection period. A warming spool will not remove the requirement for heating during the transition injection phase when the wellhead pressure has increased to above 35 barg unless two phase CO_2 flow in the well tubing is demonstrated to be acceptable. Present modelling tools cannot accurately determine if well instability will occur with two -phase CO_2 injection.

A warming spool can only heat the CO_2 to around seabed temperature of 6°C and therefore two phase CO_2 would still occur in the well tubing.

A model was developed to determine the length of warming spool required to heat the CO_2 to 6 °C following a flash of liquid CO_2 from 70 barg to 35 barg which cools the CO_2 to 1.6°C. A schematic of the conditions is shown in Figure 2-5.

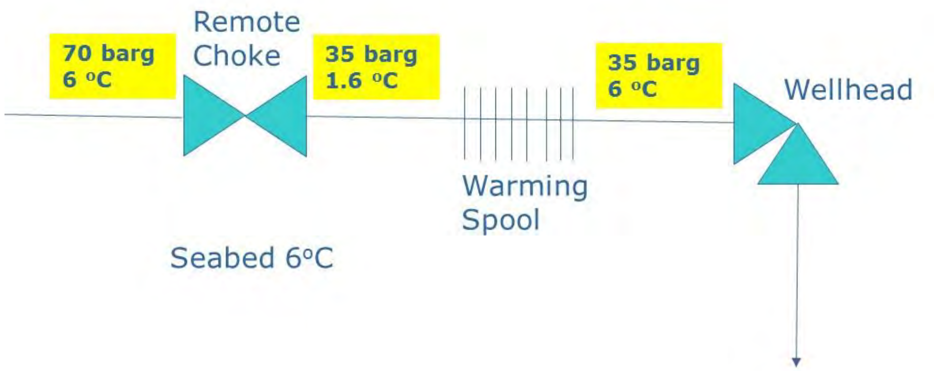

Figure 2-5 Warming Spool Schematic with Pipeline Operating Conditions

At the operating conditions of the pipeline minimal temperature drop occurs across the choke. This can be seen from the phase envelope shown in Figure 2-6. With the pipeline operating in liquid phase the temperature contours on the phase envelope are almost vertical resulting in only a 4°C temperature drop occurring during the isenthalpic flash from 70 to 35 barg across the choke. At 35 barg the CO_2 only just enters the two-phase region with 97% of the CO_2 remaining in the liquid phase at 1.6°C. With so little vaporisation occurring through pressure drop, the warming spool heat input must overcome the latent heat of vaporisation of almost all the CO_2. The latent heat required to change CO_2 phase to vapour is 76 times greater than the specific heat to change the temperature of the same mass of liquid CO_2 by 1°C. Figure 2-6 shows the large change in enthalpy (energy) required to change all the CO_2 to vapour. Given the temperature difference between CO_2 and sea is only 4°C the heat input is very small compared to the energy required. The warming spool would need to be greater than 50km in length to provide the necessary heat transfer. A warming spool is therefore not thermodynamically feasible at the CO_2 pipeline operating conditions.

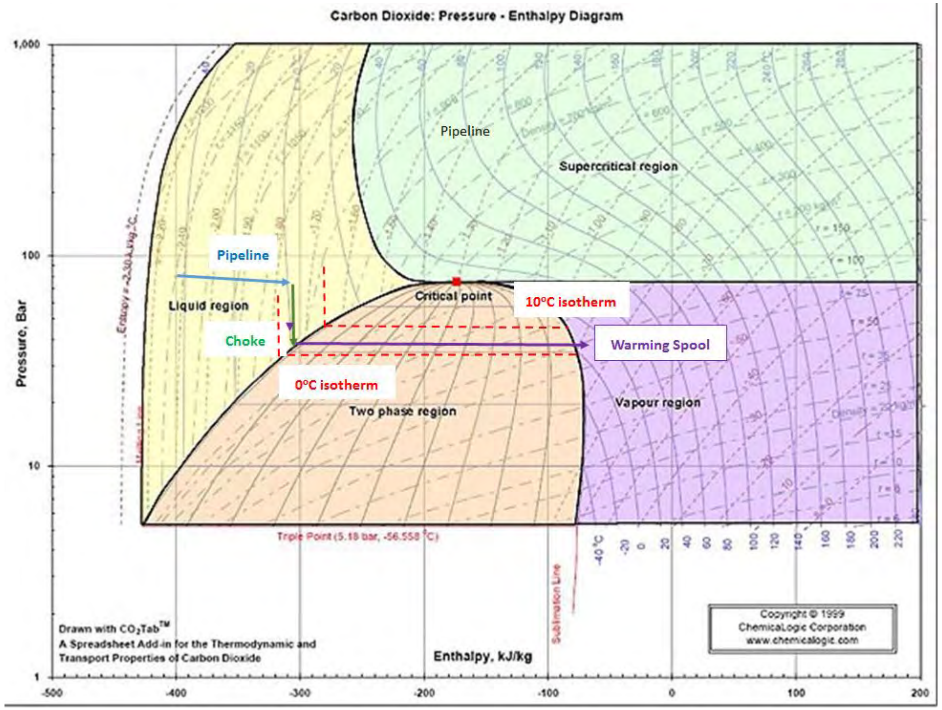

Figure 2-6 Phase Envelope Schematic of Warming Spool Operation

2.2.4 Modification of the Phase Envelope

The phase envelope of the CO_2 can be modified by blending the CO_2 with a lighter gas. This has the effect of keeping the CO_2 mixture in gas phase at higher pressure, compared to pure CO_2, and therefore avoiding the issue with liquid dropout in the pipeline and wells.

Two cases were considered, using either nitrogen or methane, to investigate the effect of varying concentrations of nitrogen and methane on the phase envelope. It is assumed that the N_2 or methane would be injected onshore, at the terminal or at the capture plant.

The effect of nitrogen and methane on the CO_2 phase envelope are broadly similar. The methane phase envelope is shown in Figure 2-7. 25 mol% methane will keep the pipeline in gas phase at up to 70 barg and 6°C. This allows CO_2 injection to continue in gas phase for much longer than pure CO_2.

The concentration of methane (or nitrogen added) would be gradually increased with time to match the required inlet pressure to the pipeline onshore to keep the CO_2 blend in gas phase. Figure 2-8 shows gas phase operation can be sustained for approximately 2 ½ years without any CH_4 blending (i.e. injecting pure CO_2). Over the following 2 ½ years, the CH_4 injection rate is stepped up in increments of circa 13 MMscfd, approximately every 6 months, until a total CH_4 injection rate of circa 65 MMscfd is reached (representing 25 mol% of the total injected gas). The source of this gas is assumed to be from the existing Hamilton gas wells, which would re-commence hydrocarbon gas production facilitated by the increasing reservoir pressure from CO_2 injection.

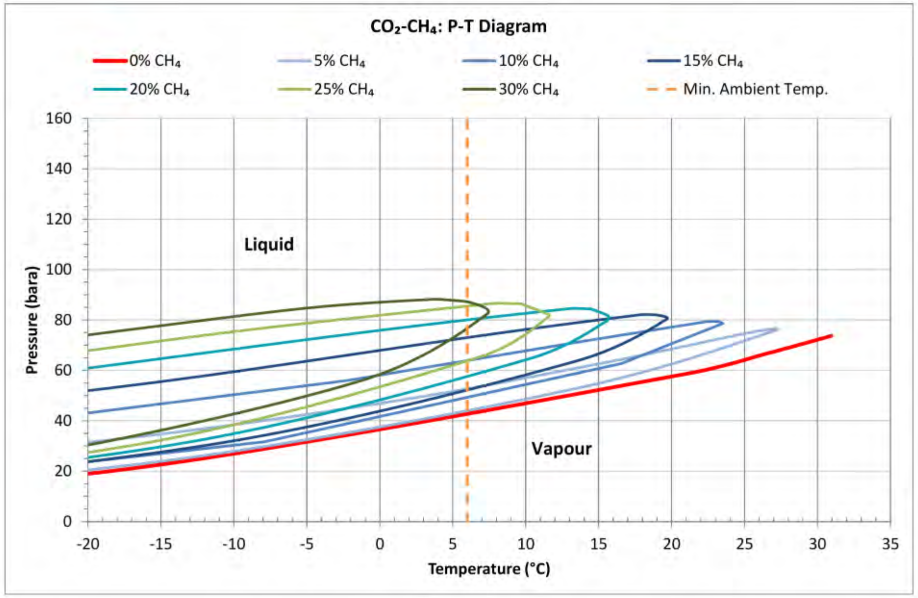

Figure 2-7 Effect of Blended Methane on CO_2 Phase Envelope

This hydrocarbon gas rate required exceeds the present production from the entire Liverpool bay fields, so it is highly unlikely the Hamilton wells would produce at such rates at the end of their design life. A more likely operating philosophy would be to limit CO_2 injection in proportion to the available rate of natural gas for blending. This would extend the length of time that gas phase operations could continue, but would not increase the total capacity of the store.

Figure 2-9 presents the injection rate of pure CO_2, blended with CH_4, to adjust the phase envelope to allow operation at higher injection pressures whilst still in the gaseous phase (without heating). These assume sufficient supply of CH_4 and don't account for utilization of CH_4 for power and compression purposes.

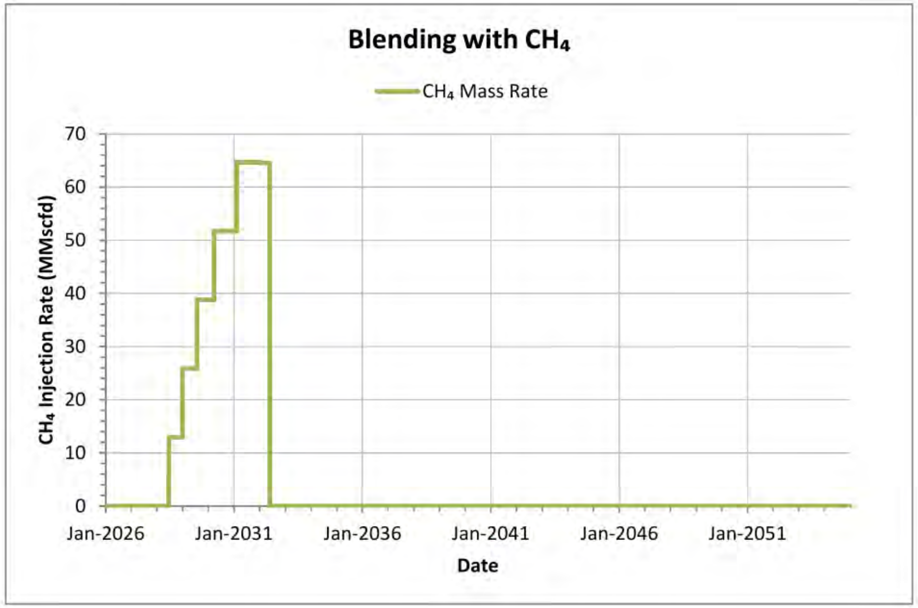

Figure 2-8 Required Methane Rates Blended with CO_2 to Maintain Gas Phase Injection

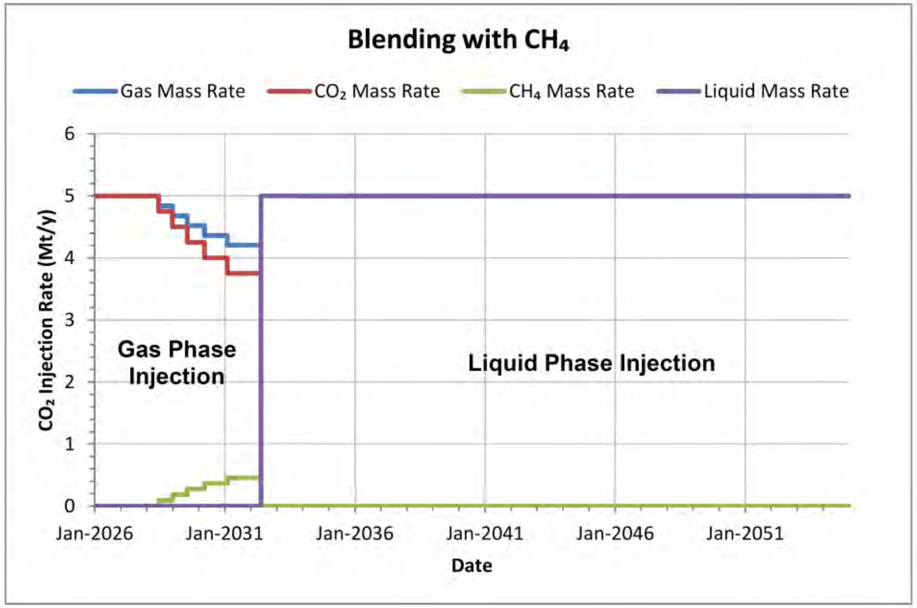

Figure 2-9 Impact of Methane Blending on CO_2 Injection Rates

The total capacity of the store reduces by approximately 3.5 million tonnes due to hydrocarbon gas injection, although production of the hydrocarbon gas would offset some of this loss. Reservoir modelling is required to confirm the balance. At 5 Mtpa, gas phase operation without heating could not be sustained for a long period (circa 2 – 3 years if injecting pure CO_2). This period can be extended to circa 6 years by blending with CH_4. However, the switchover to liquid phase injection will still be required much sooner than in the heated case (circa 13.5 years).

The complexity and cost of blending methane or nitrogen is considerable.

Methane operation would require the production from gas wells to be compressed, dehydrated and routed back to shore through the existing pipelines. A new pipeline would be required for the CO_2 / methane injection blend.

Nitrogen generation is highly energy intensive using liquefaction and at present a storage of nitrogen in reservoirs would require a change in regulations. One possible option would be to capture the CO_2 from flue gas using a less selective method than amine, which removed only oxygen, and some of the nitrogen. Membrane technology could potentially be considered although it is largely untested for carbon capture at large scale.

2.2.5 Two-Phase Operation

Operation of the wells and pipeline in two phase would present by far the simplest operational solution to CO_2 injection. Effectively the system would operate under a single pressure system from reservoir back to the onshore compression. This minimises compression energy requirements and low temperature issues. As reservoir pressure increases the phases in well and pipeline would transition from gas phase to two phase and finally to dense/liquid phase.

The main issue is uncertainty in how the system will operate during the two-phase operating period. Existing modelling tools cannot model two-phase systems particularly downward vertical CO_2 flow in the wellbore accurately. The effect of impurities in the CO_2 are also difficult to model. There are concerns a single component system changing phase rapidly will cause severe operational difficulties such as liquid holdup and slugging. There are also potential pipeline and well mechanical risks associated with pressure surges, hammer, vibration and dynamic loading in pipeline and wellbore.

2.2.6 Conclusions

Table 2-2 shows the conclusions of the designs considered to inject CO_2 into Hamilton without heating:

Non- Heating Operational Method	Conclusion
Gas Phase Operation	Feasible but reservoir capacity limited to 12 – 14 Mt in gas phase and flow rate limited to 1 Mtpa without investment in an over-sized pipeline
Insulated pipeline	Feasible but high pipeline cost and potential high temperature mechanical. Also, operational issues on start-up would require venting or circulation through a second insulated pipeline
Warm up spool	Not feasible
Phase envelope modification	Feasible but high cost and complex operations, issues with methane and nitrogen supply. Membrane technology for CO_2 capture could provide a CO_2 / N2 supply
2-phase flow	Unknown feasibility due to modelling uncertainty

Table 2-2 Key Conclusions of Hamilton CO_2 Injection Without Heating

Future work to develop the above operations could include:

- Experimental work and modelling to better understand two phase CO_2 behaviour could unlock lower cost offshore storage solution which are less complex designs and without heating.
- Feasibility study design and cost estimate of gaseous phase injection insulated pipeline development options.
- Investigation of membrane technology capture techniques to allow a blend of CO_2 and nitrogen to be injected.

3.0 T2 – Benchmark of SSAP and Commercialisation Programme Cost Estimates

3.1 Introduction

This section compares the cost estimates prepared as part of the UK CCS Commercialisation Programme (UCCP) for the development of CO_2 stores at Endurance and Goldeneye with those generated through the Strategic UK CO_2 Storage Appraisal Project (SSAP).

The Association for the Advancement of Cost Estimators provides industry guidelines for the various classes of cost estimate as summarised in Table 3-1. The bases of the estimates from the two studies are fundamentally different, reflecting the differing levels of project definition – UCCP estimates are Class 1/2 (FEED-grade) whereas the SSAP estimates are Class 3/4 (Feasibility-grade). Each class has a different uncertainty range as shown in Figure 3-1.

Class	Project Definition (%)	Purpose	Basis
5	0 – 2	Concept Screening	Capacity factored, Judgement, parametric models
4	1 – 15	Feasibility	Equipment factored, parametric models
3	10 – 40	Budget	Semi-detailed unit costs Major equipment list
2	30 – 75	Control	Detailed unit cost and material take-off
1	65 - 100	Check	Detailed unit cost and material take-off

Table 3-1 Cost Estimate Class Definitions (AACE 18R-97)

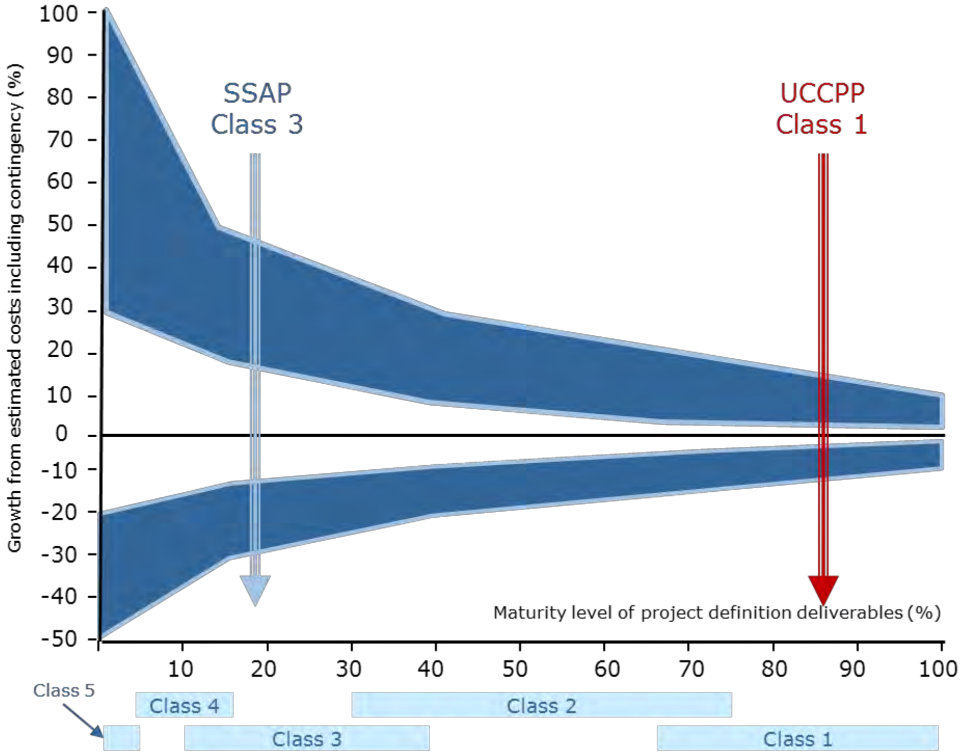

Figure 3-1 Uncertainty in Cost Estimate Classes (after AACE 18R-97)

3.2 Endurance / White Rose

During the SSAP a development plan and cost estimate was prepared for the full development of the Endurance CO_2 storage site. Subsequently, as part of the current work, a development plan and cost estimate was created that reflects the plan outlined in the Key Knowledge from the UCCP. A summary of each of these three development scenarios is provided in Table 3-2 to demonstrate the similarity between the UCCP scenario and the SSAP scenario amended for this project and provide confidence in the comparison of the cost estimates. Cost estimates are provided on a 1/1/16 basis unless specified otherwise.

Item	SSAP	UCCP	SSAP *
CO_2 Stored	520MT	54MT+	280MT
Appraisal	Seismic		Seismic
Pipeline	90km 24" 21.4mm wall	90km 24" 25.4mm wall	90km 24” 25.4mm wall
Landfall	Yes	Yes	Yes
Infield Pipelines	20km 406mm (16")	0	0
Platform	2* 4-slot, 4-leg jackets 3300Te	1* 6-slot4-leg jacket 3000	1* 4-slot, 4-leg jackets 3300Te
Wells	8 wells for each NUI Drilled in 2 phases	3 wells	3 wells
Decommissioning	10 wells, 2 NUIs	3 wells, 1 NUI	3 wells, 1 NUI

Table 3-2 Comaprison of Development Plans for Endurance

3.2.1 Endurance UCCP Capital Cost Estimate

The Key Knowledge White Rose deliverables for the commercialisation programme provides a limited breakdown of the project costs as illustrated in Table 3-3 (DECC, 2016).

Cost Element	P50 Value (£million)	P10	P90
External Utilities	49	-3%	+3%
Oxyfuel boiler, air separation unit & gas processing unit	455	-2%	+3%
Power generation plant & balance of plant	471	-3%	+4%
Onshore CO_2 pipeline & associated equipment	358	-6%	+6%
Offshore CO_2 Pipeline & associated equipment (includes pipeline, landfall metering and monitoring and, NGC business costs)	225	-11%	+11%
Storage facilities (includes the platform, the wells and any monitoring/ metering and NGC business costs)	344	-17%	+21%
Total	1,902	-6%	+7%

Table 3-3 White Rose CCS Project Captial Cost (Real 30/11/15 Basis)

3.2.2 Endurance SSAP* Capital Cost Estimate

The changes to the SSAP development plan to create a scenario very like the one documented in the UCCP are outlined in Table 3-2. The cost impacts of these changes are summarised in Table 3-4 and Table 3-5.

Adjustment Factor	Cost Impact (£million)	Comment
SSAP Transportation	177	
Removal of infield pipeline cost	-11	SSAP included an infield pipeline loop and associated umbilicals. White Rose FEED included only platform wells for initial development
Pipeline wall thickness	+20	SSAP pipeline design pressure based on 170 barg. White Rose FEED used 235 barg to allow for future transportation of CO_2 to other aquifers.
SSAP* Transportation	186	

Table 3-4 SSAP Transportation Cost Adjustments*

Adjustment Factor	Cost Impact (£million)	Comment
SSAPSSAP Storage (Facilities plus Transportation & Licenses)	600	SSAP
Removal 1 Platform	-45	SSAP included 2 platforms for a phased development of the store, WR FEED assumed only 1 platform in total
Removal of 13 wells	-282	SSAP included 16 wells over the life of the store, 8 at each platform. WR FEED assumed only 3 wells in total
SSAP* Storage	273	

Table 3-5 SSAP Storage Cost Adjustments*

3.2.3 Comparison of Endurance Capital Cost Estimates

The costs relating to offshore activity on the Endurance store from the UCCP and SSAP amended are shown in Table 3-6. The original SSAP cost estimate for is provided for reference.

Item	SSAP (£million)	UCCP (£million)	SSAP* (£million)
Pre-FID	30	0	0
Transportation	177	225	186
Facilities	134	344	89
Wells	464		184
Other (licences)	2	0	0
Total	807	569	459

Table 3-6 Comparison of Endurance Capital Cost Estimates

Cost Element	UCCP (£million)	SSAP* (£million)	Delta (£million)
Transportation	225	186	(39)
Storage	344	273	(71)
Total	569	459	(110)

Table 3-7 Transportation and Storage Cost Differences

The summary level of detail available for the UCCP cost estimate means that is only possible to speculate on the reasons for differences between the cost estimates.

The £39 million lower cost estimate for Transportation in the SSAP* case compared to the UCCP case could be due to a combination of the following factors.

- **Nature**. The UCCP estimate is for the price that the White Rose consortium would charge to execute the work. By contrast, the

SSAP* estimate is for the cost that the storage developer would incur to build and install the assets.

- **Estimating Basis.** The UCCP estimate is based on market enquiry for over 90% of the project costs which necessarily means that the size, duty and specification for major pieces of equipment and ancillaries had been defined and that the amount of piping, wiring, bulks etc. had also been estimated. The SSAP* estimate is based on the industry standard Que$tor (IHS Markit, 2015) cost estimating software suite. The SSAP* estimate is based on estimates for the identified major equipment items and factors (estimating norms) to calculate the cost for other items.
- **Steel price**. The steel index dropped by almost 70% in the period 2014/2015 so the different timing of the two estimates could account for a significant part of the difference, depending on the assumptions in use by the supply chain for UCCP and the Que$tor for SSAP*
- **Installation vessels price**. The slow-down in the oil and gas sector has led to a reduction in the rates vessel owners can charge for offshore operations.
- **NGC Business costs**. An allowance was made of Owners costs and on average this amounts to 0.5% of CAPEX. NGC business costs are unknown.

The £71 million lower cost estimate for Storage in the SSAP* case compared to the UCCP case could be due to a combination of the following factors mentioned above as well as the following items.

- **Rig and vessel prices**. Well costs account for ~ 58% of storage costs. The reduction in demand drilling rigs and other offshore vessels has caused the rates to fall and could account for some of the difference.
- **Future provision**. The platform design for WR seems to include an allowance for future modules and this may contribute to the difference in cost estimates.

3.2.4 Treatment of Contingency and Uncertainty

The White Rose team used a probabilistic approach to estimating CAPEX (DECC, 2016) and the numbers reported are the P10, P50 and P90 outputs of that analysis. No contingency was included in the estimates because no agreement had been reached regarding risk allocation between White Rose and DECC. The P10 and P90 values therefore reflect only the uncertainty of each of the cost components and provide an assessment of the accuracy of the estimate.

The SSAP cost estimates were prepared in a deterministic manner and also exclude any costs associated risk contingency. The estimates include an allowance of 30% as contingency for scope growth or change as the project definition increases. Estimating accuracy has been set at between the Class 3 and Class 4 levels.

A comparison of assumptions relating to estimating accuracy and contingency is provided in Table 3-8.

	SSAP	UCCP
Upper level of accuracy range	+40%	+21%
Lower level of accuracy range	-25%	-17%
Risk contingency	Excluded	Excluded
Growth contingency	30%	Zero

Table 3-8 Cost Estimate Accuracy and Contingency

The different levels of accuracy and approach to contingency are entirely in line with the project development process and are appropriate for the maturity of project definition in each case.

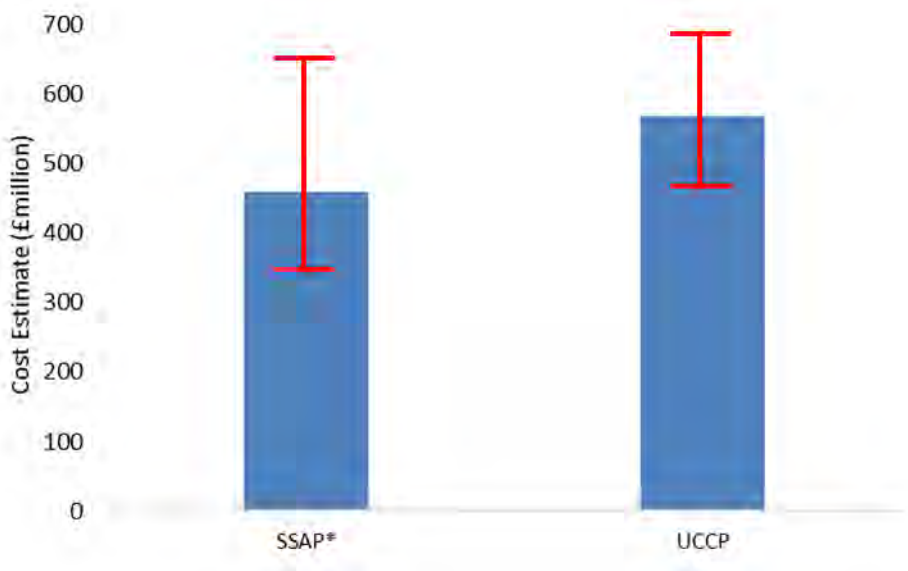

Figure 3-2 Endurance Cost Accuracy and Cost Estimates

Figure 3-2 illustrates the central estimates and notional accuracy of CAPEX from the SSAP* and UCCP processes. The lower maturity of the SSAP* estimate is evident in the larger uncertainty range. However, the difference is less than would be expected given that the UCCP estimate is based on the output of a comprehensive FEED programme. The SSAP* assessment is considered a reasonable estimate of the Endurance development at the feasibility stage because the majority of the UCCP estimating outcomes are within the SSAP* uncertainty range. The upper bound of the UCCP estimate is outside the SSAP* range indicating, perhaps, that use of a larger growth contingency factor might have been justifiable in SSAP*.

3.2.5 Operating Cost Estimate

The SSAP annual OPEX was calculated from the CAPEX estimate based on the following factors:

Transportation	0.95% of CAPEX
Facilities	5.5% of CAPEX

This equates to an annual OPEX of £20 million for transportation and storage.

The White Rose FEED (DECC, 2016) specifies the estimate for OPEX in the first year to be £47 million. The uncertainty is stated as +/-27%, no further breakdown is available. annual OPEX on NPV0 basis with an accuracy of +/-27%.

The SSAP estimate of annual OPEX is £27 million less than the UCCP estimate. Differences are likely to be due to a combination of the following factors.

- Greater level of definition of the operations and maintenance in the UCCP estimate.
- Budgetary cost estimates, or even quoted prices for services and equipment included within the UCCP estimate.
- SSAP use of estimating norms for the factors.

3.3 Goldeneye

During the SSAP a development plan and cost estimate was prepared for the development of the Goldeneye CO_2 storage site. This estimate was based on the same development scenario as the UCCP estimate and so no change was required to derive a SSAP* scenario and estimate.

3.3.1 Goldeneye UCCP Capital Cost Estimate

The Key Knowledge Goldeneye deliverables for the commercialisation programme also provided only limited breakdown of the project costs showing only transportation and storage as illustrated in Table 3-9 (Shell, 2016).

Cost Element	Cost (£million)	Uncertainty
Transport - Offshore pipeline and associated costs (includes pipeline, landfall subsea)	73	-11%/+12%
Transport - Goldeneye platform modifications	61	-11% / +12%
Storage - Wells	88	-11% / +12%
Total	222	

Table 3-9 UCCP Goldeneye CAPEX

3.3.2 Goldeneye SSAP* Capital Cost Estimate

The cost estimate for SSAP* is identical to the estimate for SSAP, as explained earlier. The SSAP estimate was derived from the cost information provided in the knowledge deliverables from the 1st CCS Demonstration Programme (Shell, 2011) and is summarised in Table 3-10.

Cost Element	Cost (£million)
Pre FID	38
Transport	65
Facilities	137
Wells	76
Total	315

Table 3-10 SSAP Goldeneye CAPEX*

3.3.3 Comparison of Goldeneye Capital Cost Estimates

A comparison of the costs allocated to transportation and storage for the two estimates is provided in Table 3-11. It is evident from this analysis that whilst the estimates are similar the SSAP* estimate 25% higher than the UCCP estimate.

Cost Element	UCCP (£million)	SSAP* (£million)	Delta (£million)
Transportation	73	65	(8)
Storage	149	213	64
Total	222	278	56

Table 3-11 Comaprision of UCCP and SSAP CAPEX Estimates for Goldeneye*

It is not possible to be certain about the reasons for the difference. However, it is clear from Table 3-9 and Table 3-10 that the biggest difference relates to the Facilities themselves rather than the pipeline or wells. The most likely explanation is that the UCCP process led to a greater understanding on the type, degree and cost of the required platform modification than was the case at the end of the Demo 1 programme.

3.3.4 Treatment of Contingency and Uncertainty

The Peterhead team used a probabilistic approach to estimating CAPEX (Shell, 2016) and the numbers reported are the P10, P50 and P90 outputs of that analysis. Risk contingency was included in the estimates but the quantity is unspecified. The P10 and P90 values therefore reflect both the uncertainty of each of the cost components and an assumed risk allocation.

The SSAP cost estimates were prepared in a deterministic manner and exclude any costs associated risk contingency. The estimates include an allowance of 21% as contingency for scope growth or change as the project definition increases (Shell, 2011). Estimating accuracy is as specified in the 1st CCS Demonstration material.

A comparison of assumptions relating to estimating accuracy and contingency is provided in Table 3-12.

	SSAP	UCCP
Upper level of accuracy range	+30%	+12%
Lower level of accuracy range	-15%	-11%
Risk contingency	Excluded	Excluded
Growth contingency	21%	Zero

Table 3-12 Cost Estimate Accuracy and Contingency

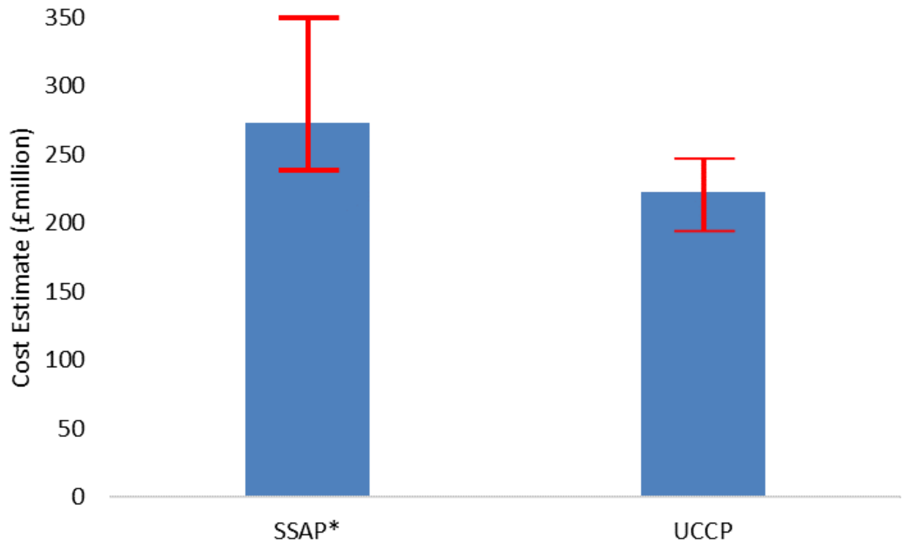

Figure 3-3 Goldeneye Cost Accuracy and Cost Estimates

Figure 3-3 illustrates the central estimates of the CAPEX from the SSAP* and UCCP processes. The lower maturity of the SSAP* estimate is evident in the larger uncertainty range. The SSAP* assessment is considered a reasonable estimate of the Goldeneye development at the feasibility stage because the majority of the UCCP estimating outcomes are within the SSAP* uncertainty range. The lower bound of the UCCP estimate is outside the SSAP* range indicating, perhaps, that use of a smaller growth contingency factor might have been justifiable in SSAP*.

3.3.5 Operating Cost Estimate

The SSAP OPEX was taken from the Demo 1 Shell OPEX costs for Goldeneye injection from St Fergus with an adjustment made a simple percentage of

CAPEX based calculation. The total was £170 million (+/-40%) broken down as follows:

Transportation	£7.5 million (£0.5 million/year x 15 years)
Storage	£162 million (£10.8 million x 15 years)

The commercialisation OPEX developed by Shell gave a total of £128 million (+24%/-15%) broken down as follows:

Transportation	£89 million
Storage	£1.8 million
Monitoring	£37.4 million

Note that the Shell report included a Year 7 workover of all the Goldeneye wells (approximately £40 million) to the transportation category. The SSAP estimate includes well and monitoring OPEX within the Storage category. The total estimates for OPEX differ by approximately £40million over the 15 year project life. It is not possible to be certain about the reasons behind the differences but the following factors are likely contributors.

- Assumptions about frequency and cost of well workovers.
- Operating and maintenance plans and costs for the infrastructure.

3.4 Conclusions

The cost estimating approach adopted during SSAP follows industry recognised recommended practise and tools for feasibility stage projects. The technical work upon which these estimates are based cost approximately £400k each.

The cost estimates generated during the UCCP FEED programmes also followed best-practise for those more detailed studies. The White Rose FEED programme cost approximately £47 million.

The capital cost estimates for the Endurance and Goldeneye sites prepared during the latter stages of SSAP differ but do compare quite well to those generated during the UCCP FEED studies. However, the absence of detail in the UCCP estimates mean that it is not possible to fully understand why.

Future studies could consider adopting a probabilistic approach to the cost estimates, however this would take considerably more time to ensure valid and credible data ranges were being used.

For similar studies in future, consideration should be given to the appropriateness of using a larger growth contingency factor.

4.0 T3 - Minimum Viable Development Scenarios

4.1 Introduction

The primary objective of this task was to define a “minimum viable development” (MVD) concept. The MVD is a development scenario which could significantly reduce the initial capital investment requirement whilst retaining flexibility and optionality to develop subsequent phases as required. Appendix 4 provides a comprehensive description of the MVD plan for each of the five sites.

4.2 Benefits of the MVD Approach

A primary advantage of the MVD approach is the reduction in the required initial capital investment. However, this typically introduces restrictions to the utility of the storage site by reducing with the injection capacity or the inventory that can be stored.

The storage inventory is highly dependent upon the development CAPEX, as illustrated in Table 4-1**.** This conclusion was also highlighted in the SSAP report.

	Reduction from Original to MVD plan (%)	
	CAPEX	CO_2 Inventory Stored
Bunter Closure 36	37	71
Forties 5, Site 1	29	43
Hamilton	67	90
Captain X	4	0
Viking A	25	50

Table 4-1 Impact of MVD Approach

The advantages and disadvantages of the MVD for each of the five SSAP CO_2 storage sites is summarised in the following pages, a more comprehensive assessment is provided in Appendix 4.

A minimum development of Bunter Closure 36 assumes 3 less wells (2) than the full development on a smaller 6 slot jacket. The 2MTpa CO_2 flow rate is lower so that a smaller 12” pipeline is required. A MVD+ case was also considered with a 4MTpa flow rate and 16” pipeline, details are provided in Appendix 4.

The MVD would not prevent a subsequent full development. However, the full exploitation of Bunter Closure 36 would require an additional pipeline to accommodate the volume of CO_2 described in the SSAP development plan.

Advantages	Disadvantages
• Wells can be added incrementally if trunkline is large enough • Additional infrastructure can be added, assuming sufficient capacity within trunkline	• Small 12” pipeline restricts injection rate resulting in only 30% of storage being utilised • Second new pipeline required to boost injection rates at high incremental cost. Pipelines are long and require landfall crossings

Table 4-2 Bunter Closure 36 Pros and Cons of MVD Approach

The minimum viable development plan for Hamilton is assumed to operate only whilst the CO_2 is in gaseous phase thus removing the need for heaters. In this scenario, it is possible that the existing Hamilton platform and pipeline could also be re-used.

.Advantages	Disadvantages
• Low OPEX – no heating required • Reuse of existing platform, pipelines and wells • Possible to phase expansion to liquid injection by adding heating later if required • Potential test site for 2-phase injection as reservoir pressure increases • Gaseous phase injection has relatively few design issues compared to liquid (low temperature, materials, cracking)	• Gas only injection restricts storage capacity to only 10% of total storage capacity with liquid phase injection with heating • Reliant upon decommissioning of Douglas Platform and handover of Hamilton facilities

Table 4-3 Hamilton Pros and Cons of MVD Approach

A minimum viable development of Forties 5, Site 1 is considered difficult due to its relative remoteness and high development cost. However, the scenario presented is for development of the southern area only which obviates the need for a subsea extension and allows for a smaller pipeline.

The MVD would not prevent a subsequent full development. However, the full exploitation of Forties 5, Site 1 would require an additional pipeline and subsea infrastructure to accommodate the volume of CO_2 described in the SSAP development plan.

Advantages	Disadvantages
• Northern injection site pipeline and wells offer a clear incremental reduction in scope and CAPEX	• Very high initial CAPEX £3 billion makes even an MVD development a very high cost at around £2 billion • Very long new trunkline (>200km) results in small cost reduction for reduced diameter • Long distance from shore makes field unattractive for MVD • Poor utilisation of reservoir storage capacity given high cost of the trunkline

Table 4-4 Forties 5, Site 1 Pros and Cons of MVD Approach

A minimum viable development of the Captain X site assumes a wholly subsea development. A lower flow rate is also assumed which allows a smaller pipeline, however life is extended to 30 years and the CO_2 inventory is unchanged from the full development plan.

The MVD is essentially a full development of the Captain X site, as envisioned by the SSAP.

Advantages	Disadvantages
• Reuse of existing Atlantic Cromarty pipeline reduces cost sensitivity and enables future expansion. • Full utilisation of storage capacity still possible over longer duration • Advances in subsea technology could make such a development feasible	• Smaller infield pipeline restricts capacity • Several design risk issues still exist with a subsea development

Table 4-5 Captain X Pros and Cons of MVD Approach

The minimum development of Viking A assumes that no heating is used to maintain single phase CO_2 and instead two phase conditions are allowed in the wellbore. In this case the flow rate is reduced to 2.5MTpa and this requires a 16" pipeline rather than the 20" pipeline in the full development.

The MVD would not prevent a subsequent full development. However, the full exploitation of Viking A would require an additional pipeline and wells to accommodate the volume of CO_2 described in the SSAP development plan.

Advantages	Disadvantages
• Lower CAPEX and lifecvcle costs	• Very long new trunkline results in small cost reduction for reduced diameter • Jacket / topsides cost relatively unchanged with reduced flowrate. • Offshore heating still required Long distance from shore makes field unattractive for MVD

Table 4-6 Viking A Pros and Cons of MVD Approach

4.3 Comparison of Development Costs

The detailed cost estimates for the MVD plans for each of the sites is provided in Appendices 5 – 10, a summary is provided in this section. Detailed cost estimates for the original development plans are not replicated here and can be found in the SSAP report (Energy Technologies Institute, 2016).

	Capital Cost (£million)		
Site	Original	MVD	Difference
Bunter Closure 36	669	424	245
Forties 5, Site 1	1025	723	302
Hamilton	281	94	187
Captain X	232	223	9
Viking A	456	343	113

Table 4-7 Development Costs Comparison

	CO_2 Inventory Stored (MT)		
Site	Original	MVD	Difference
Bunter Closure 36	280	80	200
Forties 5, Site 1	300	171	129
Hamilton	125	12	113
Captain X	60	60	0
Viking A	130	65	65

Table 4-8 CO_2 Inventory Comparison

4.4 Comparison of Life Cycle Costs

Site	Life Cycle Cost (£million)	CO_2 Stored (MT)
Bunter Closure 36	1,609	280
Forties 5, Site 1	2,968	300
Hamilton	873	125
Captain X	803	60
Viking A	1,204	130

Table 4-9 Life Cycle Costs and CO_2 Stored from the Original SSAP Work

Site	Life Cycle Cost (£million)	CO_2 Stored (MT)
Bunter Closure 36	1,095	80
Forties 5, Site 1	1,979	171
Hamilton	285	12
Captain X	622	60
Viking A	829	65

Table 4-10 Life Cycle Costs and CO_2 Inventory Stored for the MVD Plans

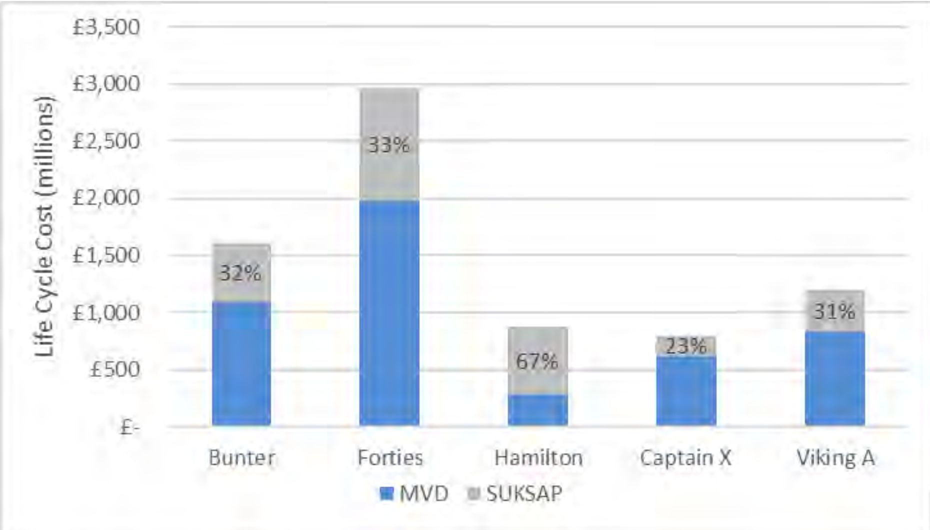

Figure 4-1 Comparison of Life Cycle Costs

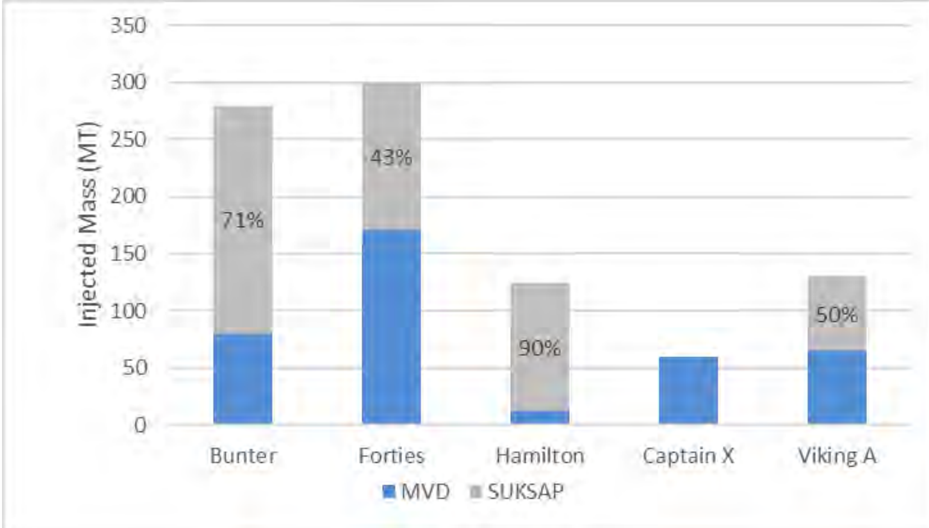

Figure 4-2 Comparison of CO_2 Inventory Stored

4.5 Comparison of Unit Costs

Site	SSAP (£/T)	MVD (£/T)
Bunter Closure 36	5.75	13.69
Forties 5, Site 1	9.89	11.06
Hamilton	6.99	23.71
Captain X	13.39	10.38
Viking A	9.26	12.76

Table 4-11 Site Cost per Tonne Comparison on a 2015 Real Basis

Site	SSAP (£/T)	MVD (£/T)
Bunter Closure 36	10.36	24.58
Forties 5, Site 1	20.76	23.04
Hamilton	10.91	36.35
Captain X	22.48	16.53
Viking A	15.34	21.15

Table 4-12 Site Cost per Tonne Comparison on a Nominal Basis

Site	SSAP (£/T)	MVD (£/T)
Bunter Closure 36	12.33	30.38
Forties 5, Site 1	18.27	26.44
Hamilton	10.94	22.37
Captain X	17.74	18.70
Viking A	16.66	33.15

Table 4-13 Site Cost per Tonne Comparison on a Levelised Basis

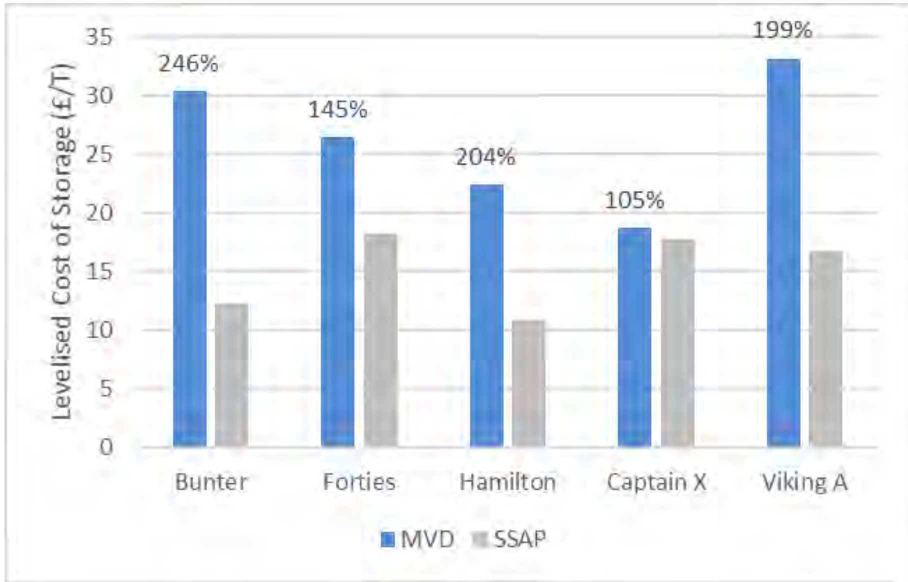

Figure 4-3 Comparison of Levelised Unit Costs

5.0 T4 - Storage Cluster Prospects

5.1 Introduction

"Hubs and Clusters" have been a long established theme within CCS to drive down costs. In the area of offshore transportation and storage the primary response to this pressure has been well characterised by National Grid Carbon's work on the Southern North Sea. This involved the careful selection and screening of a very large "oversize" storage site now called Endurance and the design of an oversized offshore (and onshore) transportation pipeline system which was capable to moving far more CO_2 than the initial target project required.

These design elements combined to deliver the lowest levelised unit cost for offshore CO_2 transport and storage of any offshore storage system yet defined at just over £9/T (Energy Technologies Institute, 2016). Unfortunately, it is also one of the most expensive pieces of offshore CCS infrastructure ever considered with a CAPEX requirement of £777m (Energy Technologies Institute, 2016).

Below the headline "economies of scale" logic lies a complex risk balancing challenge around the probability of early CCS adoption by emitters. Specifically, the balance between the return from betting on early uptake of available ullage in a project against the actual cost of building and holding that ullage available for emitters to use. In addition, over the longer term, the rate of loss of ullage must also be accounted for as the maximum operating pressures of offshore pipelines are invariably reduced over their operating lifetimes. Overall, the additional upfront cost will increase the levelised cost of the first mover project making it more challenging to justify, but will reduce the cost for follow on projects. This approach makes the first project harder to move forwards and encourages most emitters to wait for the lower cost environment of follow on projects. This impasse can only readily be broken through consistent government policy support and pressure.

This Task 4 looks at clustering in offshore transport and storage. Specifically, its considers the following: -

1. It identifies and characterises the cluster site options for the eight portfolio sites described in previous work (Energy Technologies Institute, 2016) using CO_2Stored.
2. The practical motivations behind cluster storage site developments are considered with specific examples developed for the portfolio sites within the East Irish Sea and the Southern North Sea.
3. The likelihood of each scenario will be considered including the timeframe for potential deployment and the practical issues around specific cluster development.

Finally, recommendations are drawn on the practical value of storage clusters and the work required to progress their development.

Figure 5-1 Storage Site Locations

5.2 Storage Site Hubs and Clusters

It is important to frame the definition of a "Storage Cluster" before embarking on any further consideration or analysis. For the purposes of this brief review, a storage site requires the following to be considered as part of a cluster:

- There is another site which is the identifiable anchor site or hub for the cluster
- That the new site shares critical infrastructure with the anchor site.
- That critical infrastructure will include high cost items that may be either shared at the same time or re-used later once ullage is available.

The components of infrastructure that could be usefully shared across sites are summarised in Figure 5-2. At the base of the triangle are the highest cost components which projects would benefit most from cost sharing.

Pipelines clearly service the locations at each end of the system, but with careful design they can also service a corridor of opportunities along the whole length of the system. Their reach can also be extended by subsidiary flowlines and extensions. This optionality places pipeline assets at the core of potential cluster developments

Platforms can also provide key services for local and regional site developments in addition to their primary development role. Extended reach drilling facilities located on a platform permit the development of storage sites up to 5-10km away. Platforms can also provide servicing for subsea tie backs for up to 50-70km away from the primary site.

Wells have much less utility to support cluster developments and yet some are capable of being recompleted to inject into deeper or shallower reservoirs at the location of the primary site. The addition of perforations to the Sto reservoir interval below the primary Tubaen formation was used to manage problematic pressure increases at the Snohvit CO_2 injection project in Norway. It is commonplace to have such contingency pre-planned if subsurface response is poorer than expected.

Power and Controls systems can be provided from a host platform or subsea development to adjacent sites even if such sites have their own dedicated pipeline system. Examples of this in oil and gas are the development of the Atlantic and Cromarty gas field some 35km from Goldeneye which has its own dedicated 80km gas export pipeline, but found it economically advantageous to control the wells from the Goldeneye platform via a 35km control umbilical rather than an 80km control umbilical from the beach. This kind of arrangement builds in critical dependencies which can increase commercial complexity towards the end of field life when the anchor project is no longer injecting, but the high cost facilities are simply the "dry control point" for nearby subsea infrastructure.

MMV is a key requirement of any CO_2 Storage project. MMV costs associated with repeat 3D seismic monitoring can be reduced if they can be shared across several sites. As the total cost contribution of MMV to a CO_2 storage project is small on a levelised cost basis, MMV alone is very unlikely to be the motivation for a cluster development decision.

Finally, it should be highlighted that whilst clustering and the economies of scale logic can be compelling at the front end of project development, clustering builds in critical dependency upon other assets that can reduce the robustness of project commerciality. This is becoming very obvious now in North Sea oilfield developments where the decommissioning of large platforms with very high operating costs will risk cutting short the commercial life of the cluster developments around them.

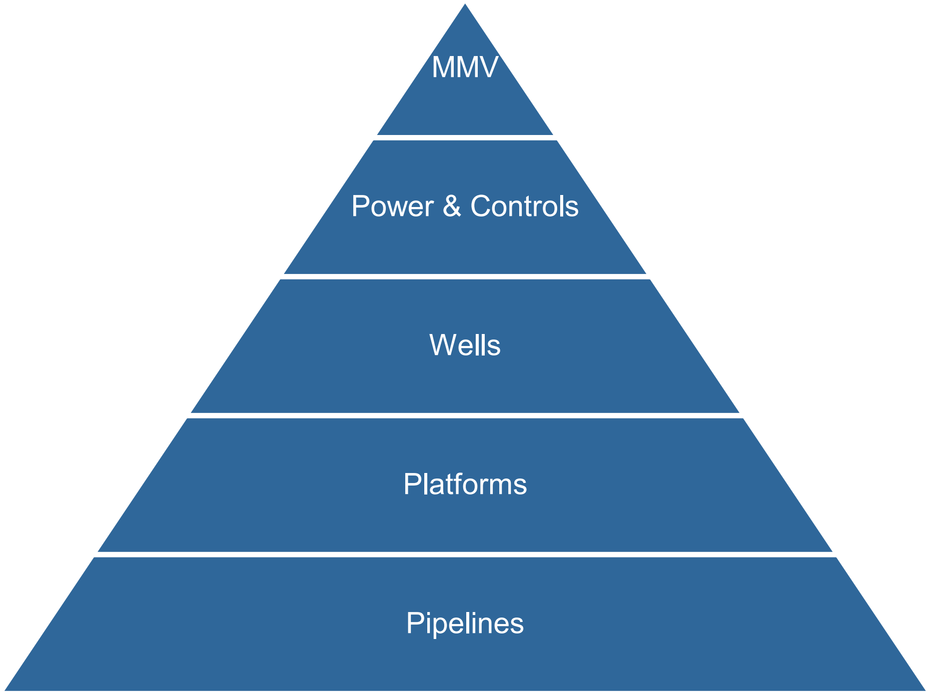

Figure 5-2 Components of Critical Cluster Infrastructure (pipelines being most important MMV being least important)

An illustration of how clustering infrastructure might develop is provided in Figure 5-3.

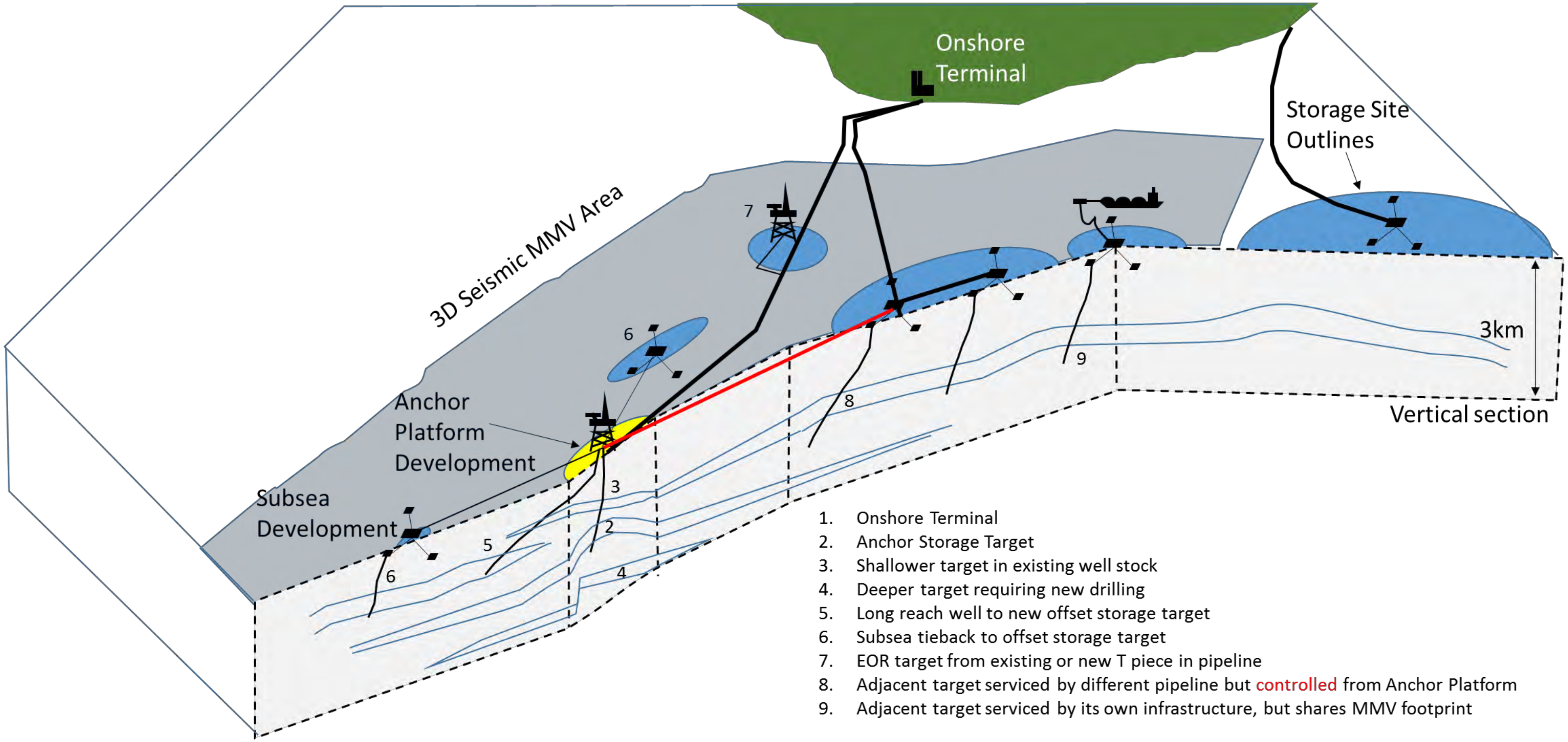

Figure 5-3 Schematic view of offshore CO_2 Storage hub and cluster development

5.3 Site Cluster Options

5.3.1 Storage Site – Viking A

Viking A is a small part of the much larger Viking gas field complex in the Southern North Sea. It was selected as an example of over 100 Permian reservoir gas fields in the basin which each have some potential for CO_2 Storage. Viking is renowned for its reservoir characterisation challenges and in particular, its' structural complexity and low permeability, but Viking A is the shallowest and simplest part of the complex. A viable CO_2 storage development at Viking A opens up significant CO_2 storage potential in the southern North Sea at other Permian gas field sites.

Obvious build out candidates from Viking A include the other depleted Viking gas field blocks nearby and the large Bunter closure overlying Viking A to the South and west. Additional very large Leman sandstone depleted gas fields will become available for CO2 storage in the late 2020's including the Leman gas field to the south and Indefatigable to the south east.

A schematic location map for Viking is shown in Figure 5-19 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-20 and Figure 5-21 where the more qualified sites, with reference to the IEAGHG guidelines, are represented by larger dots.

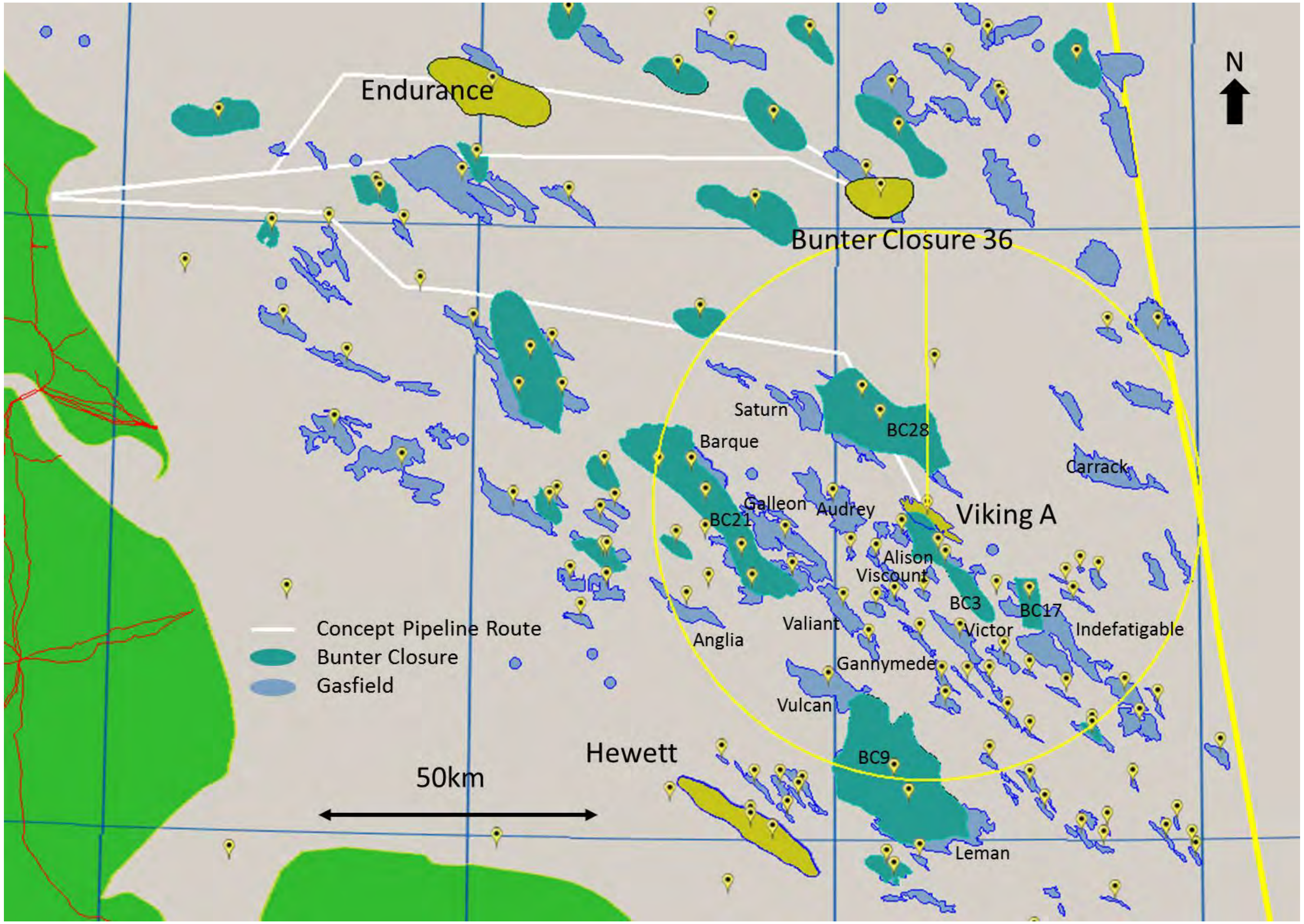

Figure 5-4 Viking A Location Schematic

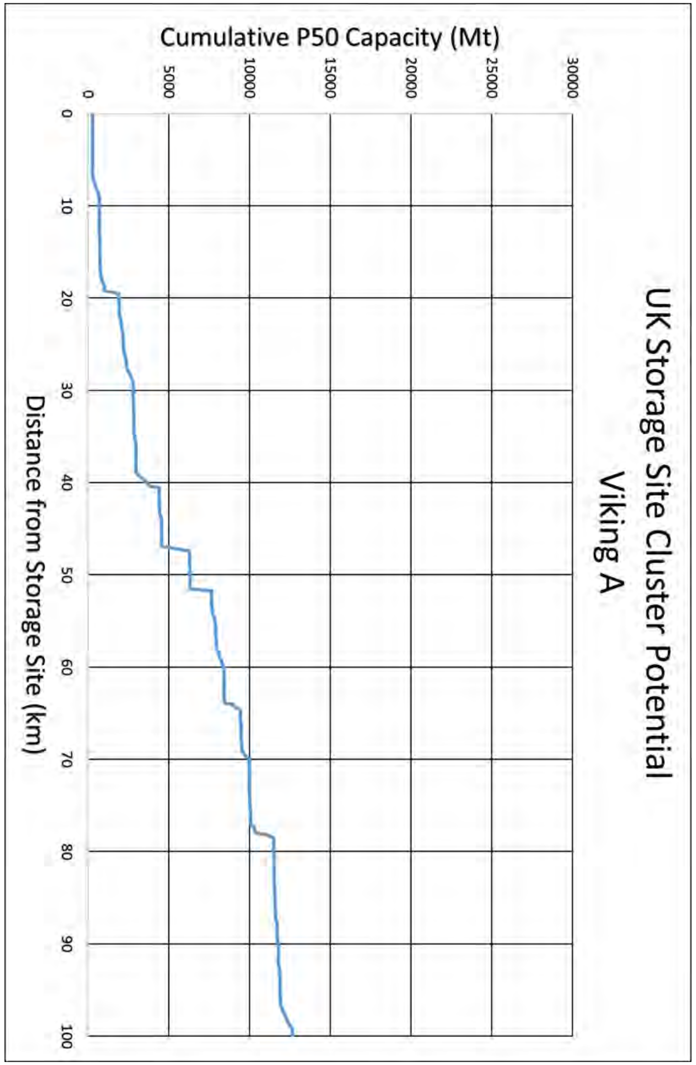

Figure 5-5 CO_2 Stored P50 Capacity within 100km of Viking A

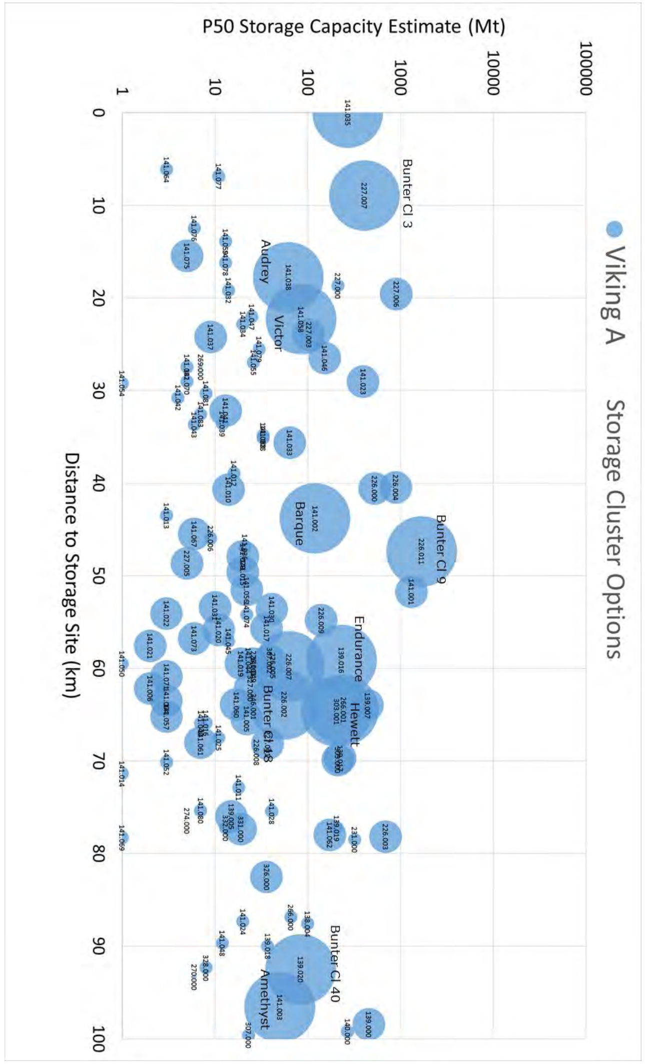

Figure 5-6 Storage Cluster Options within 100km of Viking A

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Viking gas fields	Gas	141.035	271	7	Large depleted Permian Leman gas field – Possible step out developments
Alison gas field	Gas	141.064	3	5	Small depleted Permian Leman gas field – unlikely storage development
Victoria gas field	Gas	141.077	11	5	Small depleted Permian Leman gas field – unlikely storage development
Bunter Closure 3	Saline Aquifer	227.007	409	7	Large Bunter closure above Viking gas field – clear potential for cluster addition development
Valkyrie gas field	Gas	141.076	6	5	Small depleted Permian Leman gas field – unlikely storage development
Vixen gas field	Gas	141.059	13	5	Small depleted Permian Leman gas field – unlikely storage development
Vampire gas field	Gas	141.075	5	6	Small depleted Permian Leman gas field – unlikely storage development
Viscount gas field	Gas	141.078	13	5	Small depleted Permian Leman gas field – unlikely storage development
Audrey gas field	Gas	141.038	62	7	Moderate depleted Permian Leman gas field – Possible step out developments
Bunter SST FM Zone 7	Saline Aquifer	227.000	211	5	
Vanguard gas field	Gas	141.032	14	5	Small depleted Permian Leman gas field – unlikely storage development
Bunter Closure 28	Saline Aquifer	227.006	903	6	Large Bunter closure North of Viking gas field – clear potential for cluster addition development
Ganymede gas field	Gas	141.047	25	5	Small depleted Permian Leman gas field – unlikely storage development
Victor gas field	Gas	141.058	85	7	Moderate depleted Permian Leman gas field – possible storage development
North Valiant gas fields	Gas	141.034	20	5	Small depleted Permian Leman gas field – unlikely storage development

Table 5-1 Cluster Site Options for Viking A

Storage Site – Captain X

The Captain X site is that part of the main Captain Sandstone fairway between Atlantic in the south east and Blake in the north west. It is in hydraulic communication with the depleted Goldeneye reservoir through the extensive Captain Sandstone aquifer. The storage site at Captain X was extended from its starting point at the Atlantic and Cromarty depleted gas fields which have only very small storage capacity to include the underlying saline aquifer.

Clear build out options for Captain X include the Goldeneye reservoir through either the existing platform or a subsea tie back and EOR targets such as Buzzard.

A schematic location map for Captain X is shown in Figure 5-7 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-8 and Figure 5-9 where the more qualified sites, with reference to the IEAGHG guidelines, are represented by larger dots.

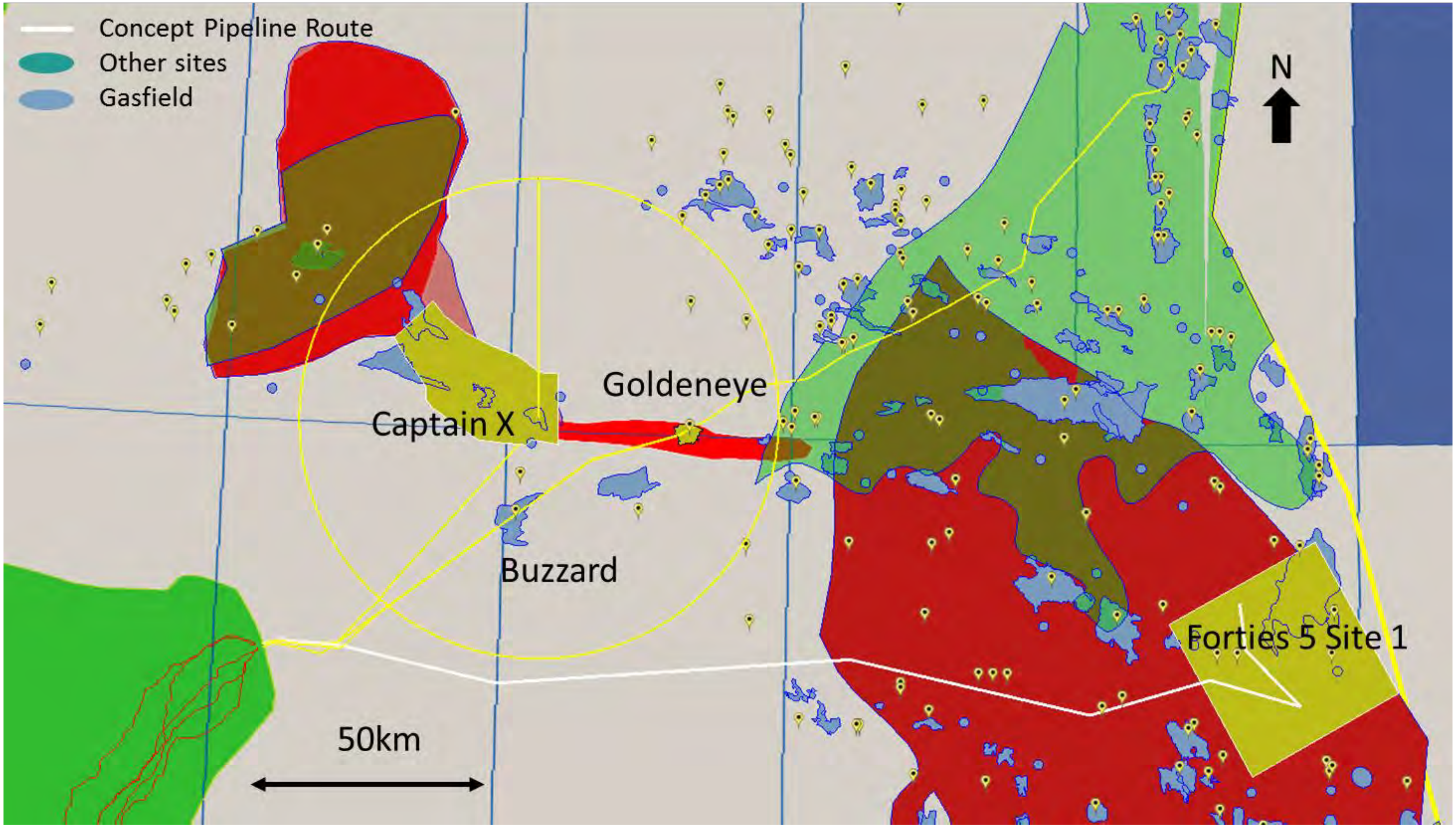

Figure 5-7 Captain X Location Schematic

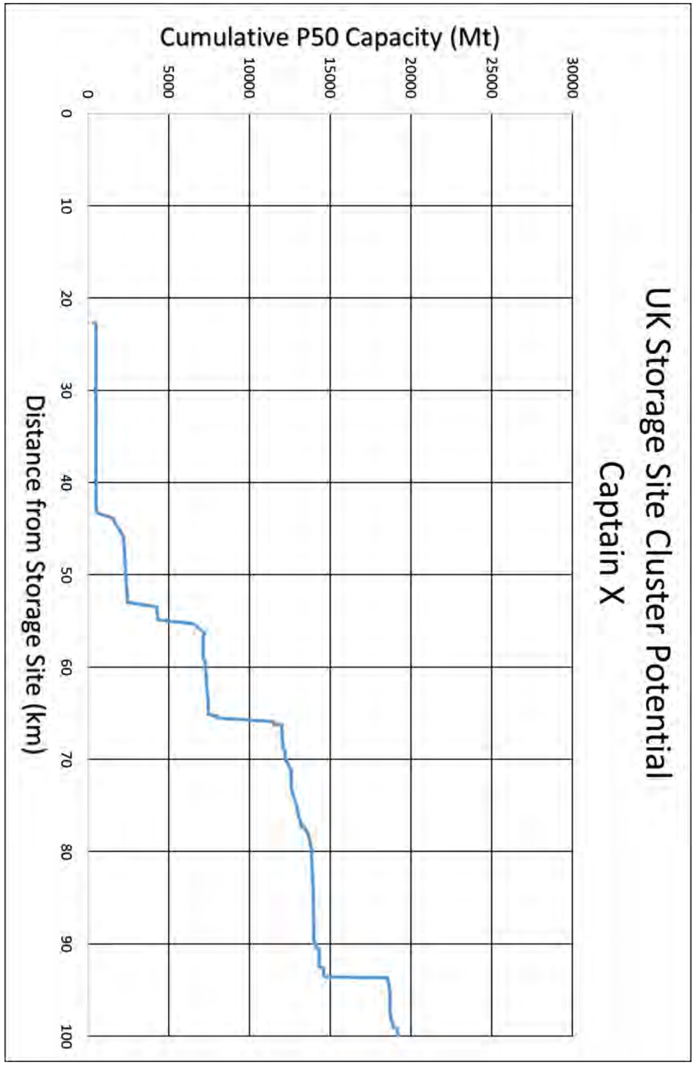

Figure 5-8 CO_2 Stored P50 Capacity within 100km of Captain X

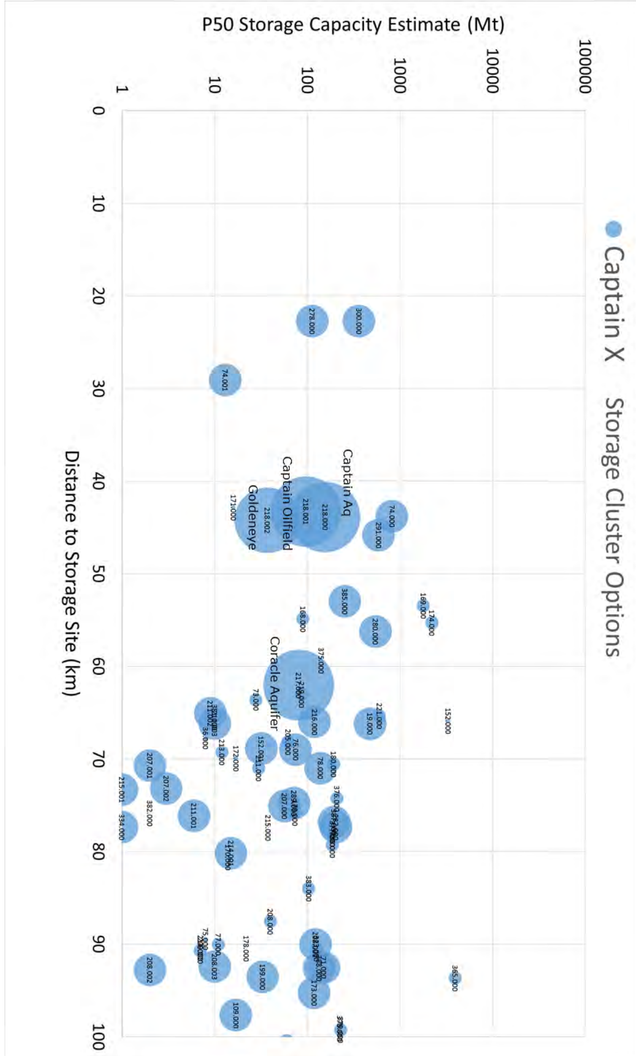

Figure 5-9 Storage Cluster Options within 100km of Captain X

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Tor_Chalk_020_01	Saline Aquifer	278.000	113	6	Low quality Upper Cretaceous saline aquifer in chalk formation – unlikely storage target
Mackerel_Chalk_020_01	Saline Aquifer	300.000	362	6	Low quality Upper Cretaceous saline aquifer in chalk formation – unlikely storage target
Buzzard Oil Field	Oil & Gas	74.001	13	6	Mid / Upper Jurassic Sandstone oil field with EOR potential
Stroma_020_03	Saline Aquifer	171.000	16	4	Small Open Saline aquifer in Mid Jurassic Sandstone – confined -
Captain Oil Field	Oil & Gas	218.001	97	7	Large oilfield in lower Cretaceous Captain Sandstone with usable CO_2 capacity
Burns_013_21	Saline Aquifer	74.000	825	6	High quality Upper Jurassic open saline aquifer– potential storage target
Captain_013_17	Saline Aquifer	218.000	156	7	Large Open Saline aquifer in Lower Cretaceous Captain Sandstone
Goldeneye Gas Condensate Field	Gas Condensate	218.002	37	7	Small Lower Cretaceous depleted gas field
Mackerel_Chalk_014_26	Saline Aquifer	291.000	590	6	Low quality Upper Cretaceous saline aquifer in chalk formation – unlikely storage target
Claymore_014_18_CLONE	Saline Aquifer	385.000	255	6	Large high quality Upper Jurassic saline aquifer in a confined unit – potential storage target
Strathrory_013_16	Saline Aquifer	169.000	1797	5	Low quality Devonian saline aquifer– unlikely storage target
Orcadia_013_13	Saline Aquifer	168.000	90	5	Low quality Devonian saline aquifer– unlikely storage target
Findhorn_013_21	Saline Aquifer	174.000	2227	5	Low quality Permian saline aquifer– unlikely storage target
Tor_Chalk_014_25	Saline Aquifer	280.000	547	6	Low quality Upper Cretaceous saline aquifer in chalk formation – unlikely storage target
Scapa Oil Field	Oil & Gas	219.001	-7	6	Lower Cretaceous Oilfield undergoing waterflood – no capacity anticipated.

Table 5-2 Cluster Site Options for Captain X

5.3.2 Storage Site – Forties 5 Site 1

The Forties 5 Site 1 location was selected from the much larger Forties 5 Saline aquifer site as an excellent location from which to start to develop an open aquifer system. The development plan acknowledged the scale of the target and the low storage efficiencies of such open aquifer systems by planning a staged development with a subsea cluster ties back to a host anchor platform. It is therefore by design a cluster development. When storage efficiencies are low in such systems, large areas are required which cannot be developed from single drill centres. A step out cluster of tie backs is an obvious solution. Other options include the Everest depleted gas field and EOR targets such as Nelson, Forties, Montrose and Arbroath fields.

A schematic location map for Forties 5 Site 1 is shown in Figure 5-10 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-11 and Figure 5-12 where the more qualified sites with reference to the IEAGHG guidelines are represented by larger dots.

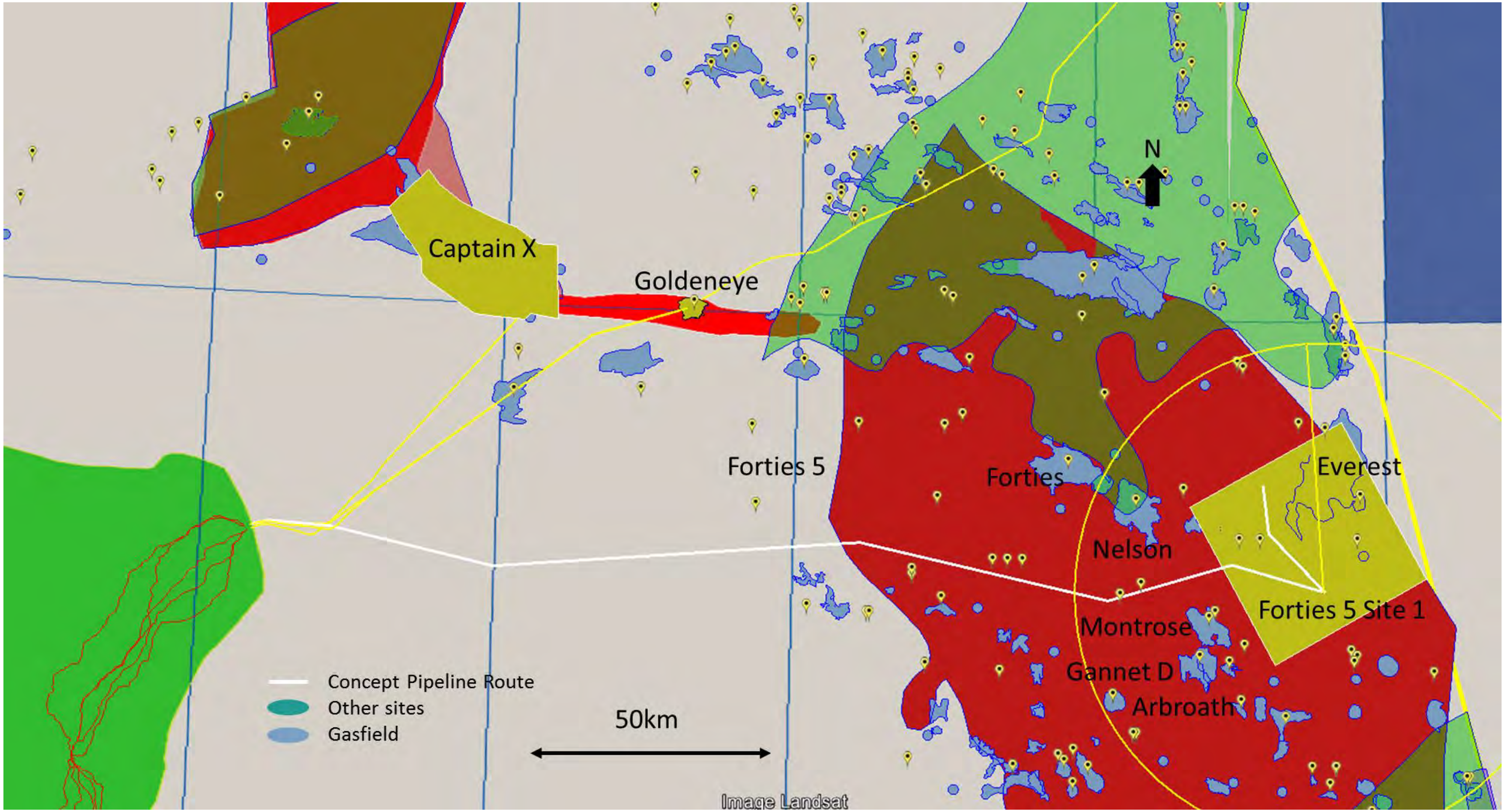

Figure 5-10 Forties 5 Site 1 Location Schematic

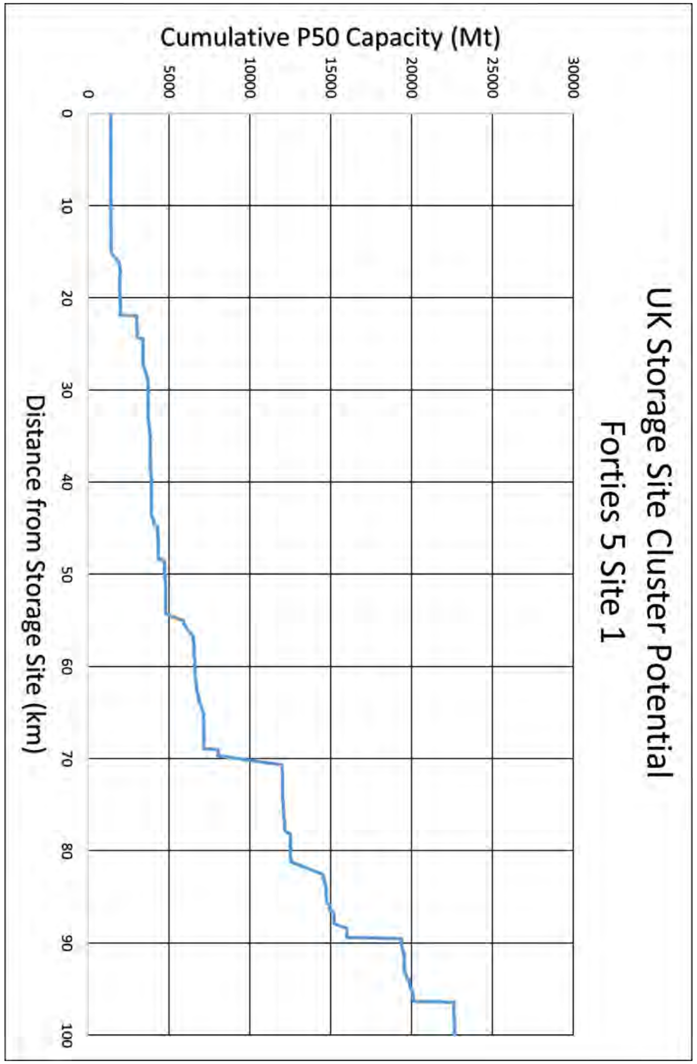

Figure 5-11 CO_2 Stored P50 Capacity within 100km of Forties 5 Site 1

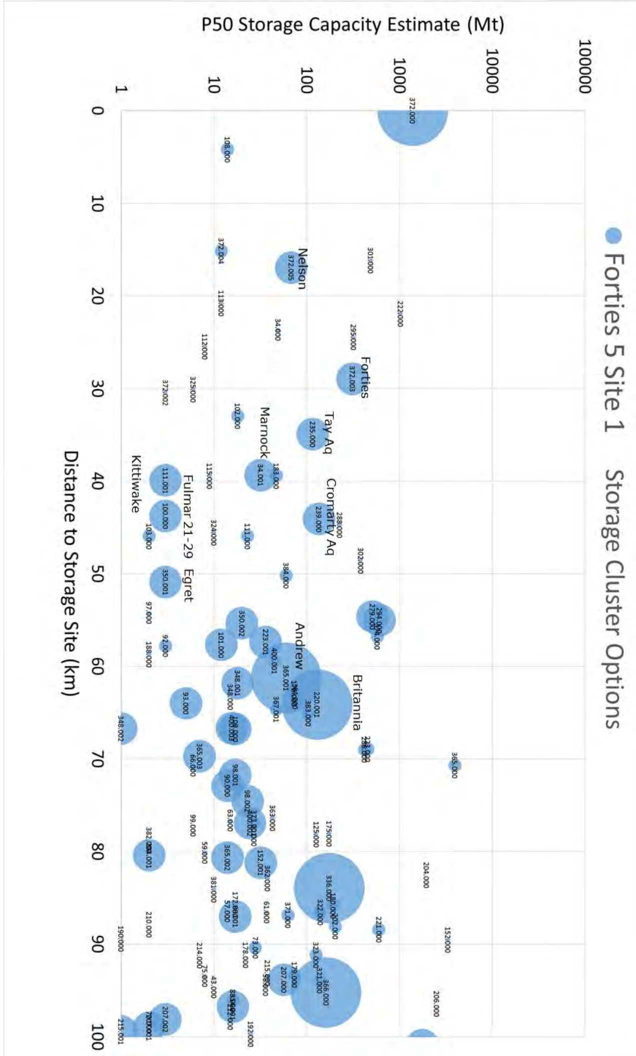

Figure 5-12 Storage Cluster Options within 100km of Forties 5 Site 1

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Forties 5	Saline Aquifer	372.000	1388	7	Huge open saline aquifer system capable of hosting several CO_2 storage developments.
Fulmar_022_16	Saline Aquifer	108.000	14	5	Small confined Jurassic saline aquifer – unlikely storage development
Montrose oil field	Oil & Gas	372.004	12	5	Large oilfield in hydraulic connectivity with primary Forties 5 Site 1 location. Significant EOR potential
Tor_Chalk_022_18	Saline Aquifer	301.000	491	4	Low quality saline aquifer in chalk formation – very unlikely CO_2 storage target
Nelson oil field	Oil & Gas	372.005	68	6	Large oilfield in hydraulic connectivity with primary Forties 5 Site 1 location. Significant EOR potential
Arbroath oil field	Oil & Gas	372.001	0	5	Large oilfield in hydraulic connectivity with primary Forties 5 Site 1 location. Significant EOR potential
Fulmar_022_12	Saline Aquifer	113.000	12	4	Small confined Jurassic saline aquifer – unlikely storage development
Gannet D oil field	Oil & Gas	235.003	0	6	Small Horda formation oilfield – unlikely storage development
Auk_022_13	Saline Aquifer	222.000	1024	4	Confined low quality Permian saline aquifer – unlikely storage development target
Skagerrak_022_08b	Saline Aquifer	34.000	49	4	Confined low quality Triassic saline aquifer – unlikely storage development target
Pentland_021_14	Saline Aquifer	184.000	0	4	Small confined Jurassic saline aquifer – unlikely storage development
Mackerel_Chalk_022_18	Saline Aquifer	295.000	320	4	Low quality saline aquifer in chalk formation – very unlikely CO_2 storage target
Fulmar_022_13	Saline Aquifer	112.000	8	4	Small confined Jurassic saline aquifer – unlikely storage development
Fulmar_021_14	Saline Aquifer	110.000	0	4	Small confined Jurassic saline aquifer – unlikely storage development
Forties oil field	Oil & Gas	372.003	312	6	Very large oilfield in hydraulic connectivity with primary Forties 5 Site 1 location. Significant EOR potential

Table 5-3 Cluster Site Options for Forties 5 Site 1

5.3.3 Storage Site – Bunter Closure 36

Bunter Closure 36 is one of a series of large water bearing Bunter structures located in the Southern North Sea. It is very similar in aspect to the Endurance structure which was the subject of National Grid Carbon's appraisal and development activity.

Bunter Closure 36 is underlain by the deeper Carboniferous Schooner gas field, and whilst of limited capacity (24MT – CO_2Stored) it does offer some potentially useful capacity to accommodate any short term contingency requirements should there be any operational interruptions at the main Bunter target.

Other options for clustering include a range of other nearby Bunter closures including Bunter Closure 1 and Bunter Closure 37. Also with a 160km pipeline route from Barmston, there are additional structured which could be ties into T pieces along the pipeline.

A schematic location map for Bunter Closure 36 is shown in Figure 5-13 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-14 and Figure 5-15 where the more qualified sites with reference to the IEAGHG guidelines are represented by larger dots.

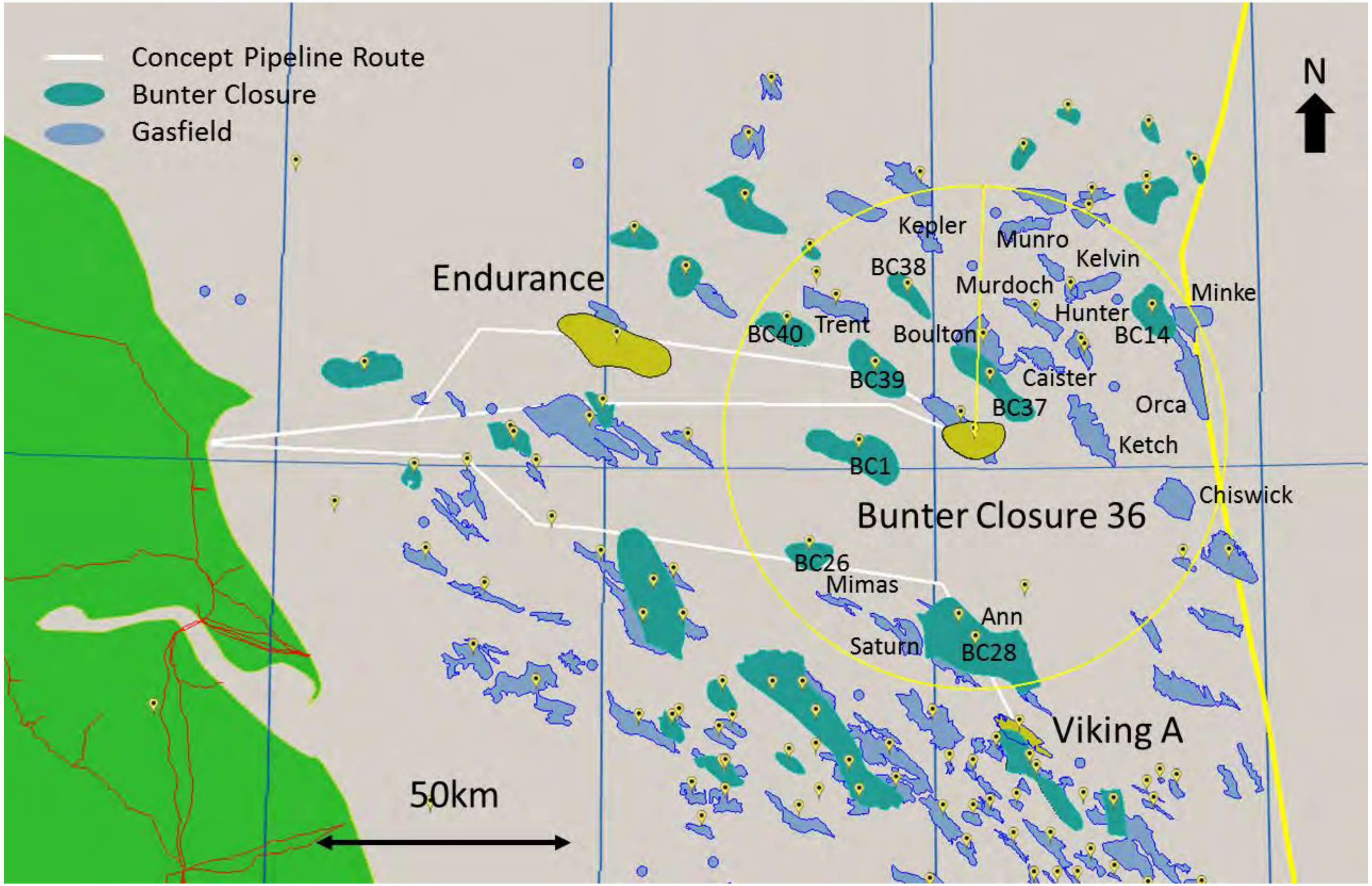

Figure 5-13 Bunter Closure 36 Location Schematic

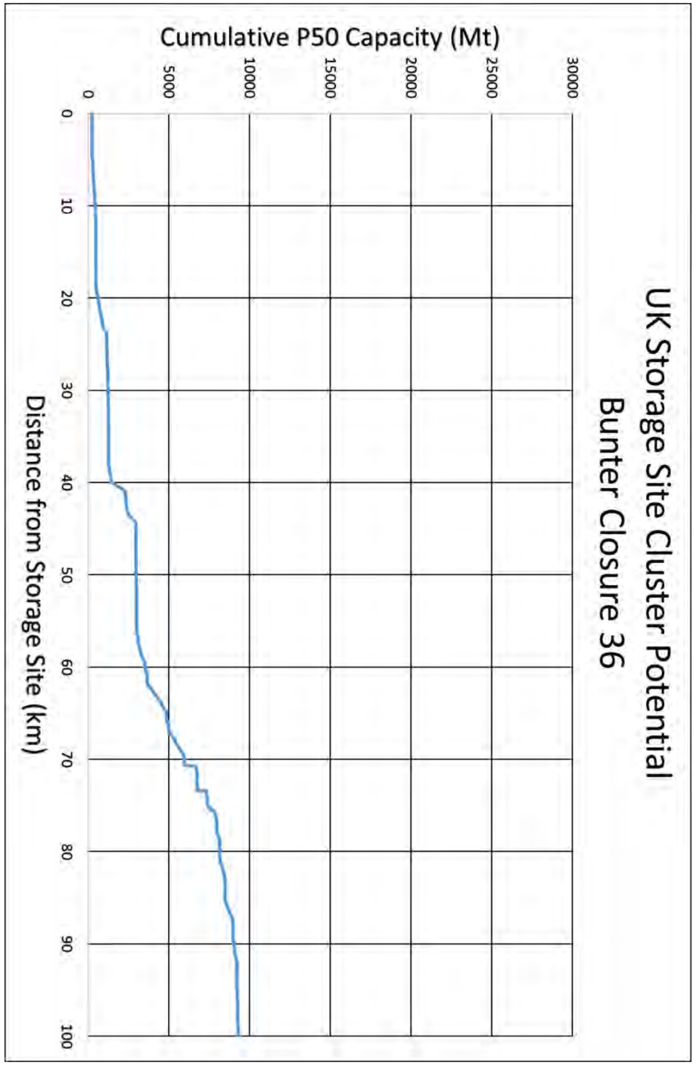

Figure 5-14 CO_2 Stored P50 Capacity within 100km of Bunter Closure 36

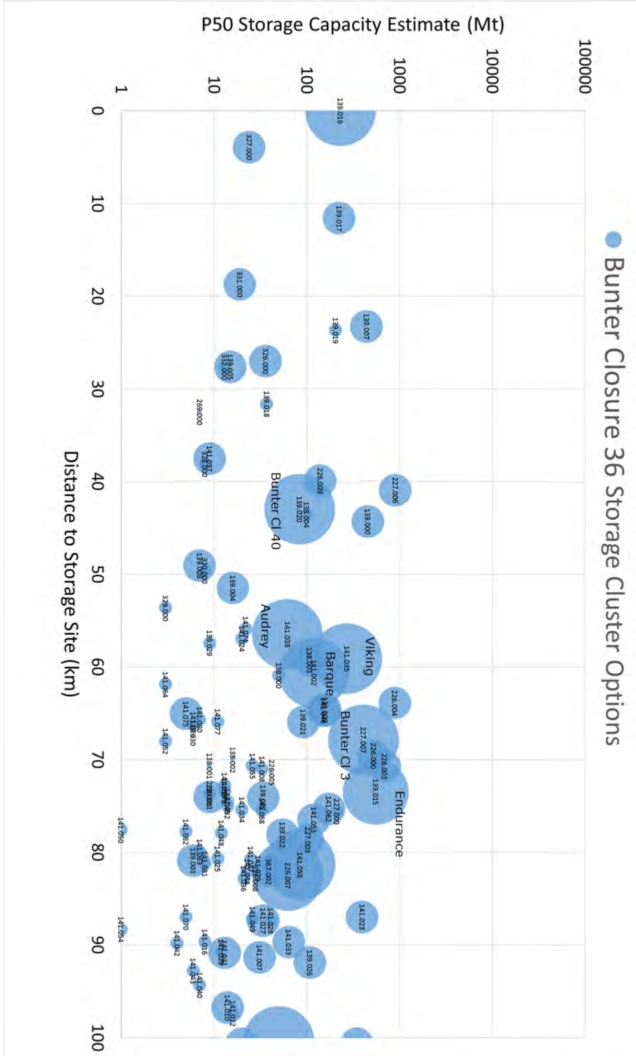

Figure 5-15 Storage Cluster Options within 100km of Bunter Closure 36

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Schooner gas field	Gas	327.000	24	6	Small Carboniferous depleted gas field – unlikely storage development
Bunter Closure 37	Saline Aquifer	139.017	224	6	Very large Bunter closure – potential storage development
Boulton gas field	Gas	331.000	19	6	Small Carboniferous depleted gas field – unlikely storage development
Bunter Closure 1	Saline Aquifer	139.007	442	6	Very large Bunter closure – potential storage development
Bunter Closure 39	Saline Aquifer	139.019	205	5	Large Bunter closure – potential storage development
Murdoch gas field	Gas	326.000	36	6	Small Carboniferous depleted gas field – unlikely storage development
Caister C gas field	Gas	332.000	13	5	Small Bunter depleted gas field – unlikely storage development
Caister B gas field	Gas	139.005	15	6	Small Bunter depleted gas field – unlikely storage development
Bunter Closure 38	Saline Aquifer	139.018	37	5	Small Bunter closure to the north west of BC36 – unlikely storage development
Chalk Group 2	Saline Aquifer	269.000	7	4	Open saline aquifer – tight formation – very unlikely storage development
Hunter Gas Field	Gas	139.006	0	6	Small Bunter depleted gas field – unlikely storage development
Ann gas field	Gas	141.037	9	6	Small Permian Leman depleted gas field – unlikely storage development
Trent gas field	Gas	328.000	8	5	Small depleted Carboniferous gas field north west of BC 36 – unlikely storage development
Bunter Closure 26	Saline Aquifer	226.009	140	6	Usable capacity Bunter closure south west of BC36. Possible storage development
Bunter Closure 28	Saline Aquifer	227.006	903	6	Very large Bunter closure to the South of BC36 high potential storage development

Table 5-4 Cluster Site Options for Bunter Closure 36

5.3.4 Storage Site – Hamilton

The Hamilton Gas field in the East Irish Sea is a highly pressure depleted, shallow target storage site. The reservoir is the Ormskirk Sandstone, the Triassic equivalent of the Bunter in this area. The East Irish sea reservoirs are challenged on the basis of reservoir quality which generally seems only to have been preserved by hydrocarbon fills. As a consequence, many of the saline aquifer targets are poor quality. The site lies some 40km south of the huge South Morecambe gas field.

A schematic location map for Hamilton is shown in Figure 5-16 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-17 and Figure 5-18 where the more qualified sites with reference to the IEAGHG guidelines are represented by larger dots.

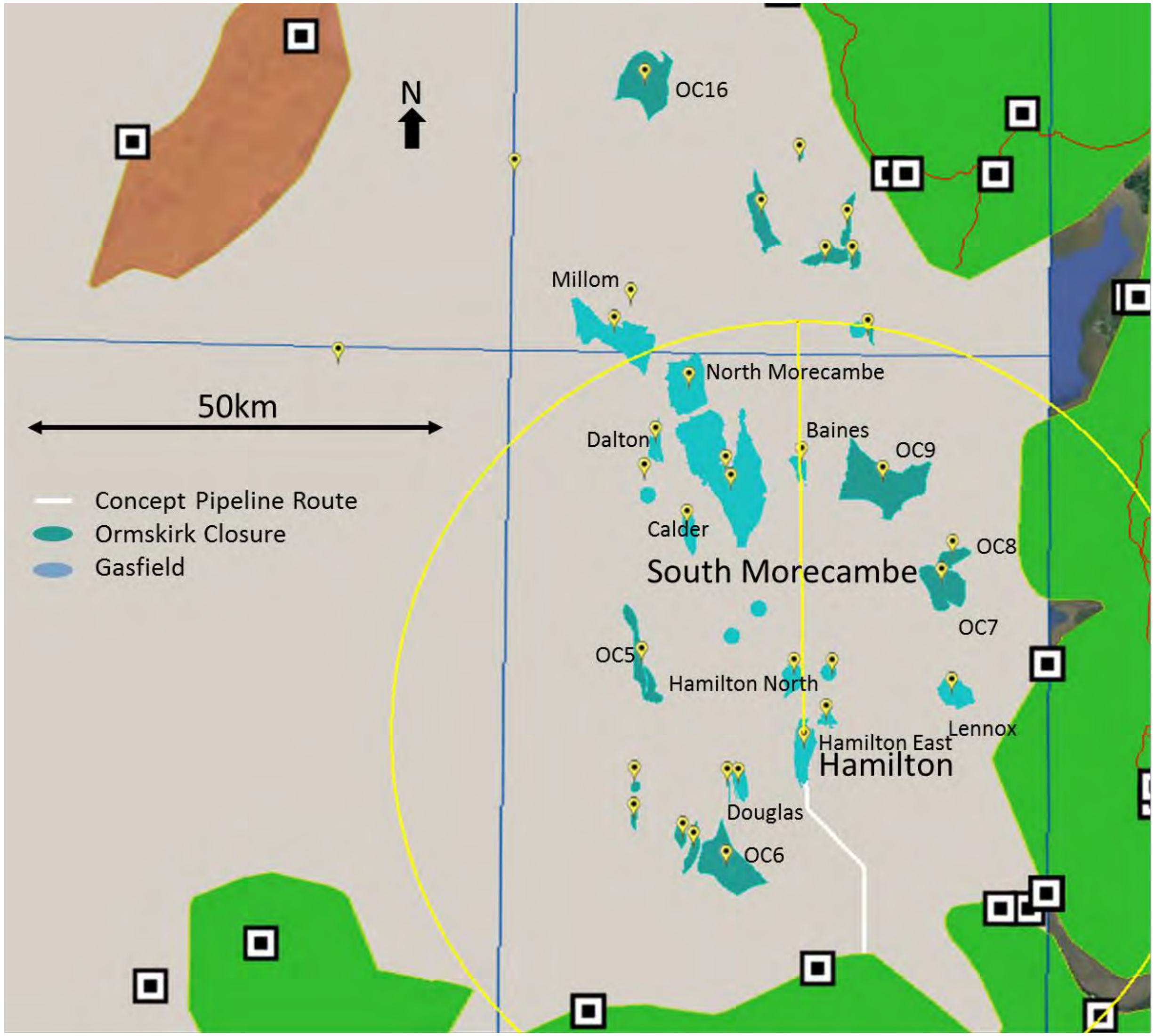

Figure 5-16 Hamilton Location Schematic

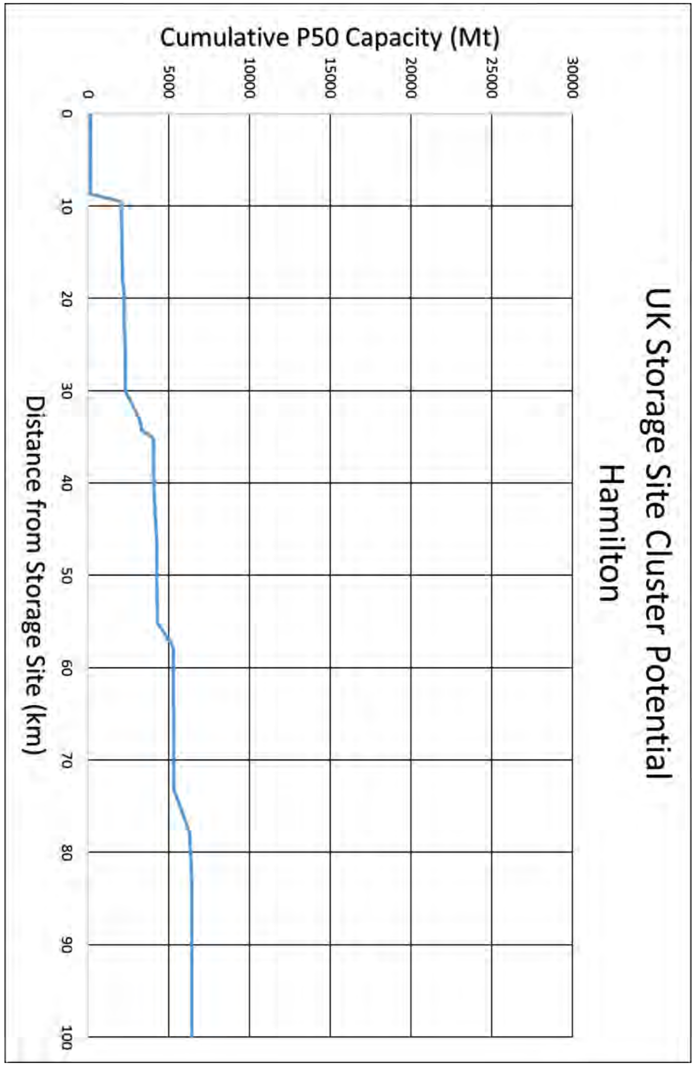

Figure 5-17 CO_2 Stored P50 Capacity within 100km of Hamilton

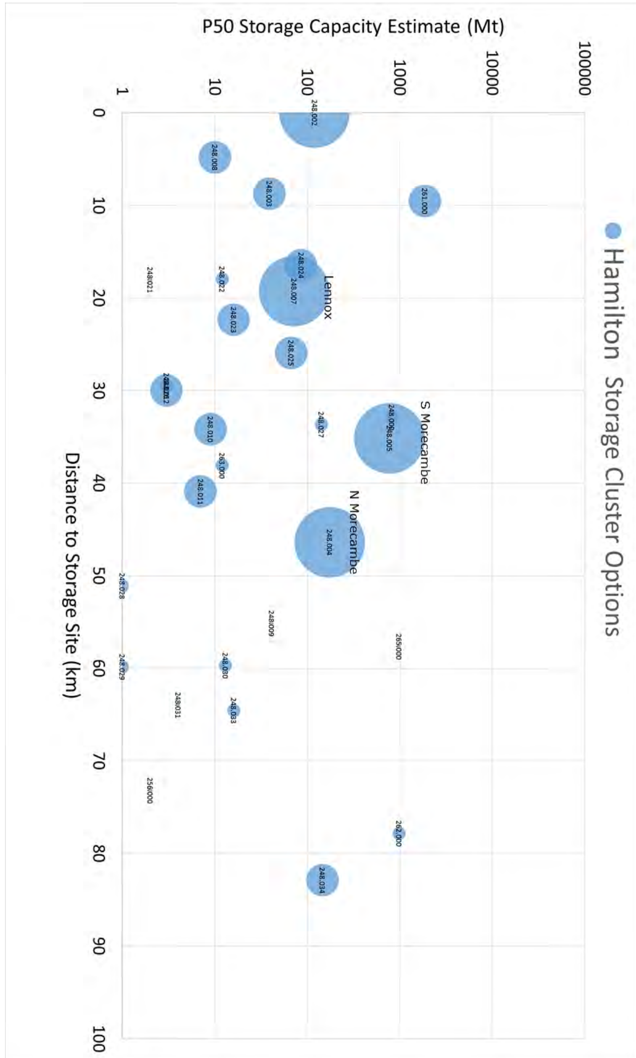

Figure 5-18 Storage Cluster Options within 100km of Hamilton

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
South Morecambe gas field	Gas	248.005	776	7	Very large depleted gas field with very large storage capacity. Represents a build out for any NW England CCS project beyond Hamilton
North Morecambe gas field	Gas	248.004	175	7	Large depleted gas field providing a large storage capacity
Ormskirk closure 16	Saline Aquifer	248.034	146	6	Moderate capacity saline aquifer structure west of Hamilton – Possible storage development
Ormskirk closure 6	Saline Aquifer	248.024	86	6	Small capacity saline aquifer structure south west of Hamilton – Unlikely storage development
Lennox oil & gas field	Oil & Gas	248.007	72	7	Small capacity oil/ gas field to the east of Hamilton – Unlikely storage development
Ormskirk closure 7	Saline Aquifer	248.025	67	6	Small capacity saline aquifer structure north East of Hamilton – Unlikely storage development
Hamilton North gas field	Gas	248.003	39	6	Small capacity gas field to the north of Hamilton – Unlikely storage development
Ormskirk closure 5	Saline Aquifer	248.023	16	6	Small capacity saline aquifer structure North west of Hamilton – Unlikely storage development
Hamilton East gas field	Gas	248.008	10	6	Small capacity gas field to the east of Hamilton – Unlikely storage development
Bains gas field	Gas	248.010	9	6	Small capacity gas field to the north of Hamilton – Unlikely storage development
Dalton gas field	Gas	248.011	7	6	Small capacity gas field to the north of Hamilton – Unlikely storage development
Calder gas field	Gas	248.012	3	6	Small capacity gas field to the north of Hamilton – Unlikely storage development
Douglas West oil field	Oil & Gas	248.018	0	6	Small capacity oil field to the west of Hamilton – Unlikely storage development.
Douglas oil field	Oil & Gas	248.001	0	6	Small capacity oil field to the west of Hamilton – Unlikely storage development.

Table 5-5 Cluster Site Options for Hamilton

5.3.5 Storage Site – Goldeneye

Goldeneye (GY) is a depleted gas field in the Central North Sea and is operated by Shell. It is currently undergoing decommissioning after the UK Government decision in November 2015 to abandon the UK CCS Commercialisation competition.

Goldeneye's primary role was as a first mover demonstrator and represented a rare presentation of:

- A field which had reached the end of its hydrocarbon production life but had not yet been decommissioned.
- Unmanned facilities that were less than ten years old
- Dedicated pipeline less than 10 years old

A schematic location map for Goldeneye is shown in Figure 5-19 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-20 and Figure 5-21 where the more qualified sites with reference to the IEAGHG guidelines are represented by larger dots.

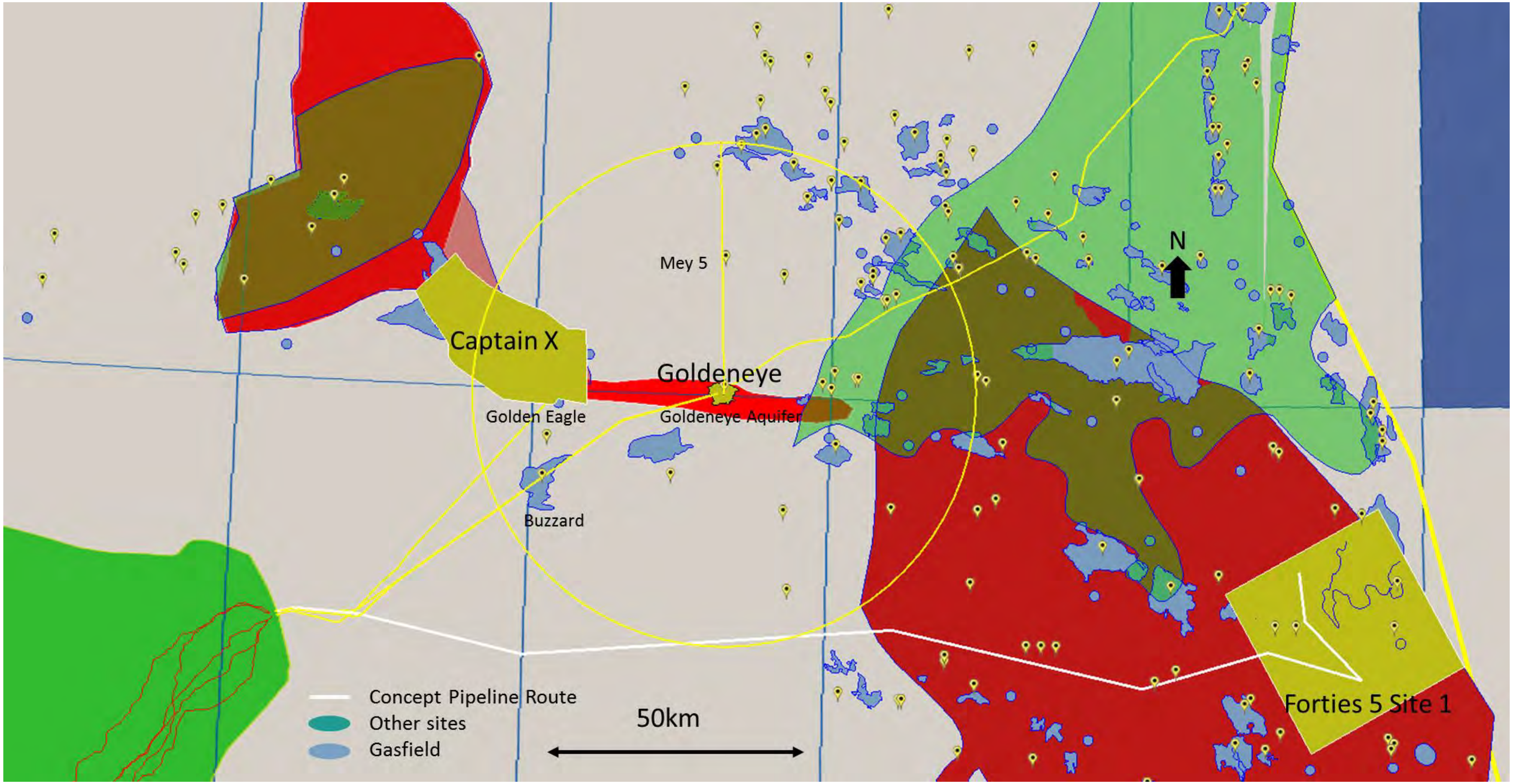

Figure 5-19 Goldeneye Location Schematic

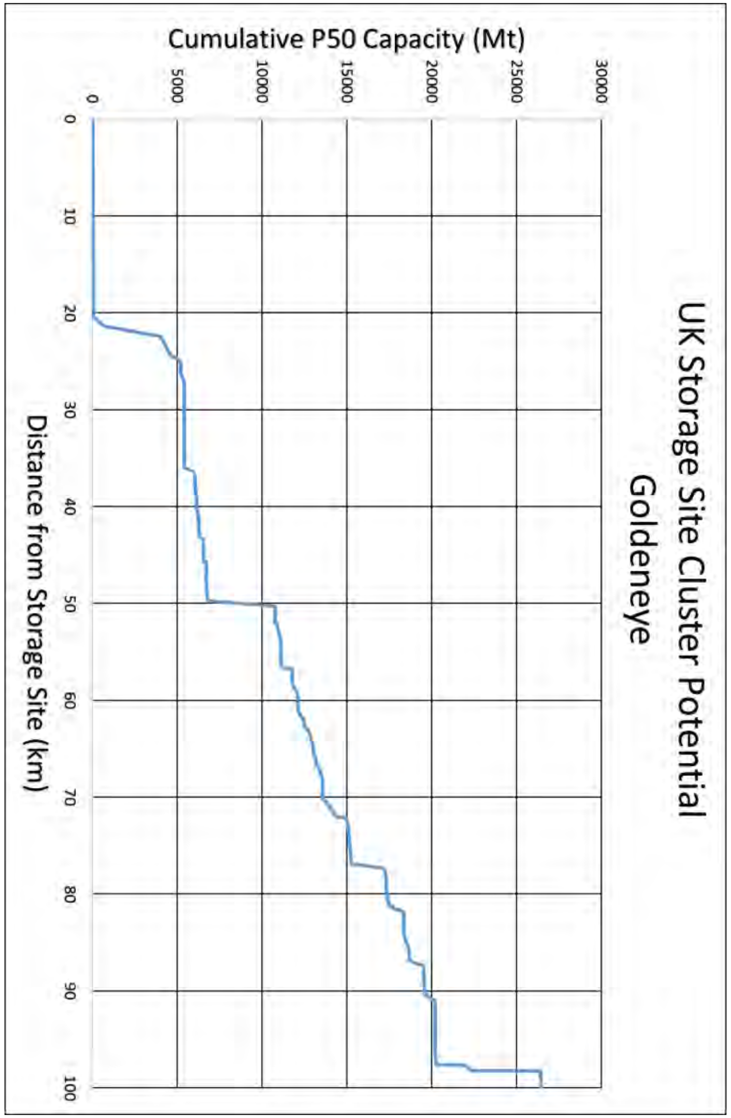

Figure 5-20 CO_2 Stored P50 Capacity within 100km of Goldeneye

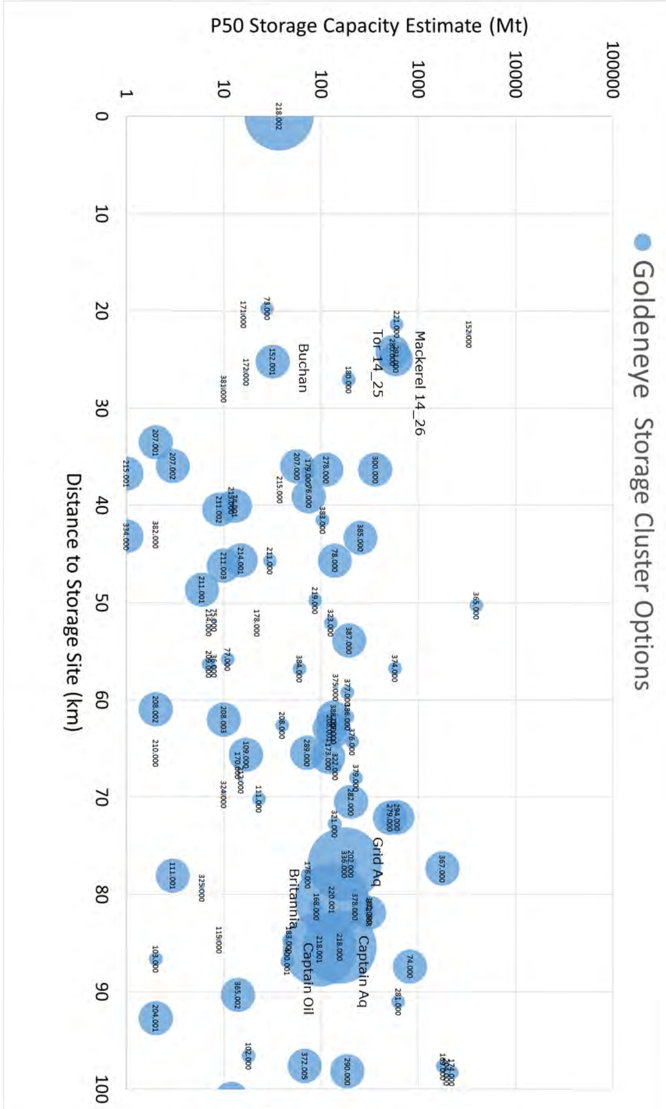

Figure 5-21 Storage Cluster Options within 100km of Goldeneye

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Captain X	Open Saline Aquifer	218.003*	60*	7	Open Saline aquifer west of GY. Important not to build a weak link in to any project through the extended use and dependency upon a platform with limited lifespan. Probably some MMV wins and learnings from injecting into the same geological formation. Clear build out option for a GY development
Mey 5	Open Saline Aquifer	365.000	3958	5	Open Saline aquifer above the GY region. Concerns over whether GY platform and wells have the ability to have life extended. Shallower target would afford a low cost extension to GY capacity
Goldeneye Aquifer	Open Saline Aquifer	218.004*	40*	7	Semi confined saline aquifer below and adjacent to GY structure. The wells at GY are poorly placed to inject CO_2 with reasonable storage efficiency in the underlying aquifer. Wells reaching deep into the formation are required - these are not available at GY without further drilling. Also preliminary simulation work suggests that injection into the GY area may be pressure limited by the Grampian Arch which may mean that brine production may be required to match high injection rates >2MT/yr on a sustained basis. Possible build out, but difficult access from GY platform for optimum performance.
Maureen 2	Open Saline Aquifer	367.000	1777	6	Shallower Target- Again shallower target would afford a low cost extension to GY capacity
Dornoch	Open Saline Aquifer	335.000	506	6	Shallower target but located east of Goldeneye -
Tor Chalk	Open Saline Aquifer	278.000	113	6	This is part of the overburden containment package and very unlikely to be developed as an alternative storage site
Mackerel	Open Saline Aquifer	300.000	362	6	This is part of the overburden containment package and very unlikely to be developed as an alternative storage site
Auk	Fully Confined Saline Aquifer	221.000	601	5	Deeper Carboniferous target. Very unlikely build out target
Firthcoal	Fully Confined Aquifer	381.000	10	4	Deeper Carboniferous target some 15km SE of GY. Very unlikely build out target
Innes		317.000			Deeper Carboniferous target . Very unlikely build out target
Burns		74.000			Lr Cretaceous Burns Sandstone target below GY Very unlikely build out target
Stroma		171			Mid Jurassic Stroma Sandstone target below and to SE of GY Very unlikely build out target
Pentland	Fully Confined Saline Aquifer	180.000			Pentland Sandstone target below and to SE of GY Very unlikely build out target
Buzzard	Oil field	74.001	13*(without EOR)	6	Lower Cretaceous - Upper Jurassic Burns + Buzzard Sand development to 40km south west of Goldeneye. Possible EOR build out option – subject to GY longevity
Golden Eagle	Oil Field	N/A	N/A	N/A	Lower Cretaceous - Upper Jurassic Burns + Buzzard Sand development to west of Goldeneye. Possible EOR build out option – subject to GY longevity

Table 5-6 Cluster Site Options for Goldeneye

5.3.6 Storage Site – Hewett

Hewett depleted gas field is unique in the southern North Sea basin in that it is a very large gas field with a Triassic Reservoir. The site is currently operated by ENI and was the subject of a significant FEED study in 2010 by Eon linked to the Kingsnorth CCS project.

There are two main sands, the Hewett and Upper Bunter. Capacities are likely to exceed 200MT. Legacy wells are a key issue at Hewett and will require careful integrity assessment. As a result, a containment issue involving a legacy well might be one of the more likely reasons for a cluster site development. Clear options for alternative nearby sites include the large Leman gas field and Bunter structures such as closure 9.

A schematic location map for Hewett is shown in Figure 5-22 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-23 and Figure 5-24 where the more qualified sites with reference to the IEAGHG guidelines are represented by larger dots.

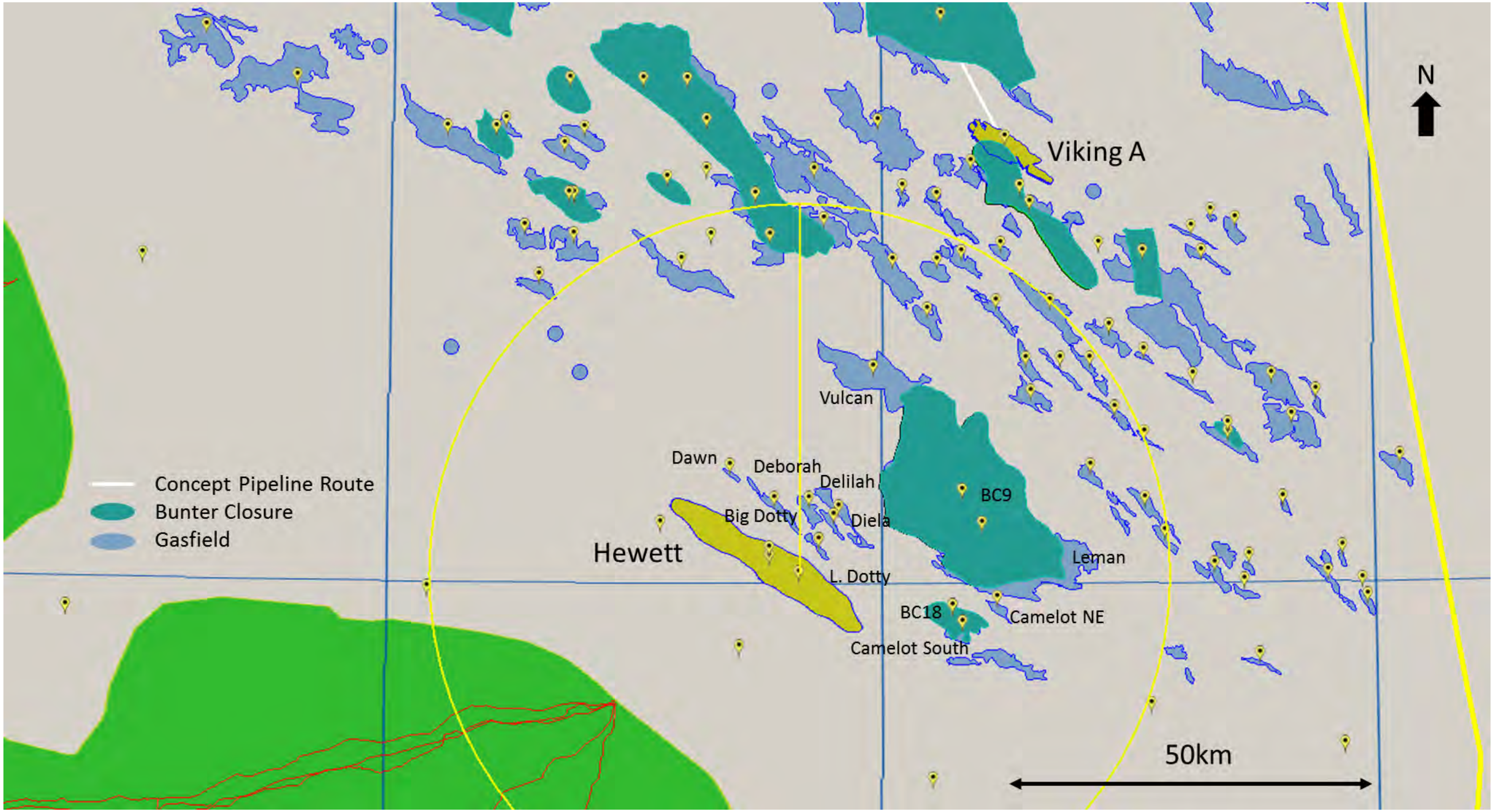

Figure 5-22 Hewett Location Schematic

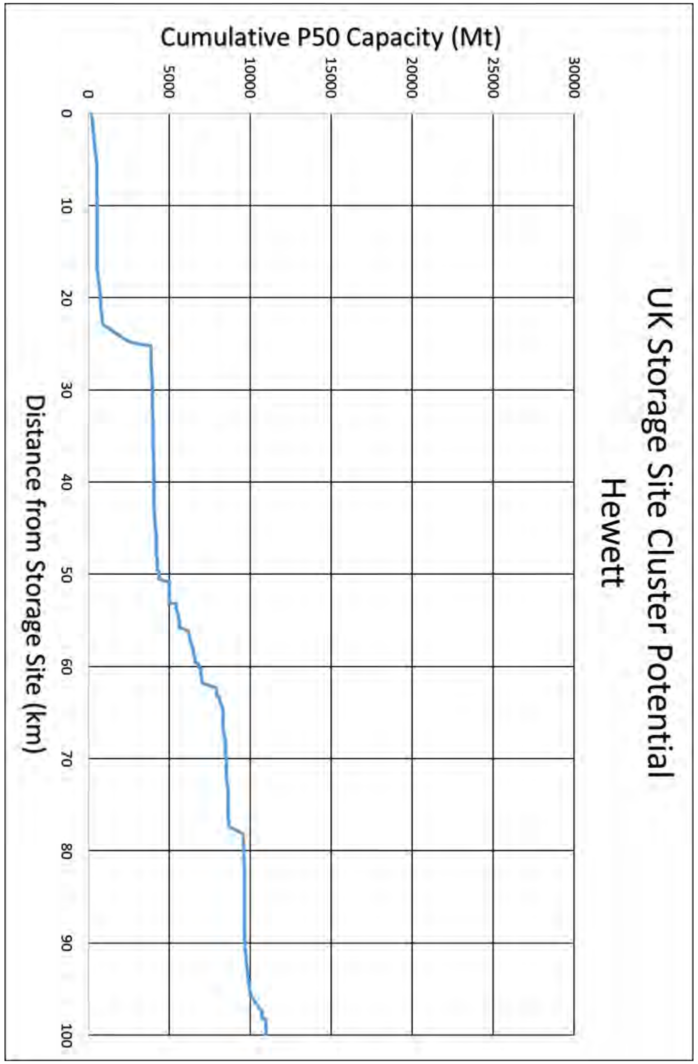

Figure 5-23 CO_2 Stored P50 Capacity within 100km of Hewett

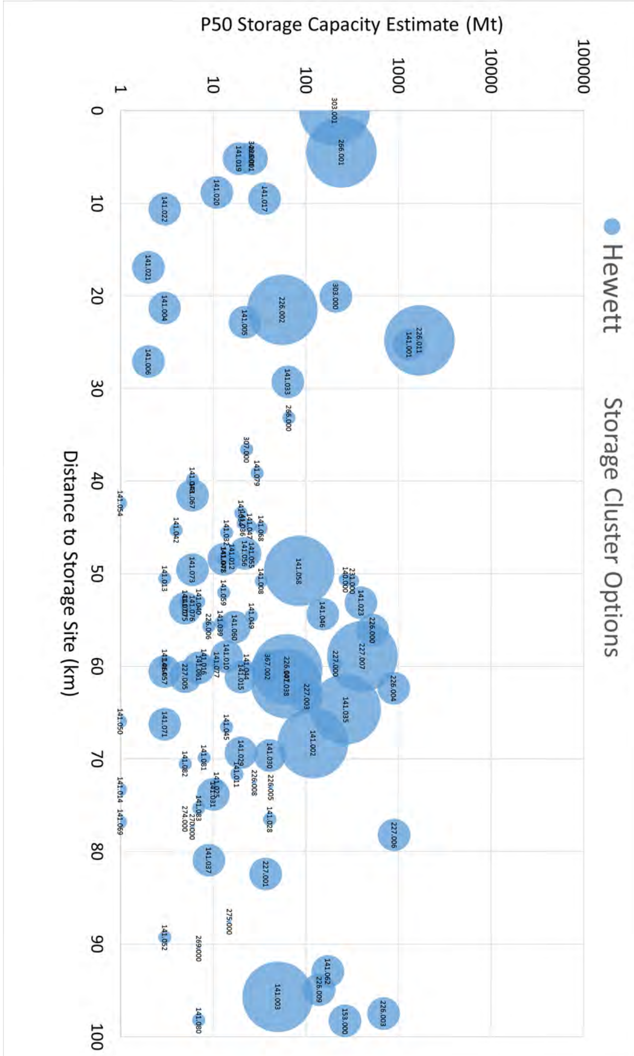

Figure 5-24 Storage Cluster Options within 100km of Hewett

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Little Dotty gas field (Bunter Sdst)	Gas	226.001	26	6	A small Bunter gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Little Dotty gas field (Leman Sdst)	Gas	141.019	19	6	A small Permian Leman gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Della gas field	Gas	141.020	11	6	A small Permian Leman gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Deborah gas field	Gas	141.017	36	6	A small Permian Leman gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Big Dotty gas field	Gas	141.018	0	6	A small Permian Leman gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Delilah gas field	Gas	141.022	3	6	A small Permian Leman gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Dawn gas field	Gas	141.021	2	6	A small Permian Leman gas field satellite north of Hewett unlikely to be considered for CO_2 storage development
Bunter Sandstone Formation Zone 12	Saline Aquifer	303.000	211	6	Large Open aquifer sandstone which represents a secondary target after Bunter closures are developed.
Camelot North gas field	Gas	141.004	3	6	A small Permian Leman gas field east of Hewett unlikely to be considered for CO_2 storage development
Bunter Closure 18	Saline Aquifer	226.002	56	7	A small Bunter closure above Camelot gas field unlikely to be the target of a storage development
Camelot Central South gas field	Gas	141.005	22	6	A small, very high quality Permian Leman gas field east of Hewett unlikely to be considered for CO_2 storage development
Bunter Closure 9	Saline Aquifer	226.011	1691	7	A large Bunter Closure above the Leman gas field which may be the target for a dedicated CO_2 storage development.
Leman gas field	Gas	141.001	1316	6	A very large Permian Leman gas field east of Hewett which is likely to be the focus of a dedicated CO_2 storage development once gas production has ended.
Camelot Northeast gas field	Gas	141.006	2	6	A small Permian Leman gas field east of Hewett unlikely to be considered for CO_2 storage development
Vulcan gas field	Gas	141.033	64	6	A small Permian Leman gas field 30km north unlikely to be considered for CO_2 storage development

Table 5-7 Cluster Site Options for Hewett

5.3.7 Storage Site – Endurance

Endurance (or 5/42) is an open saline Bunter aquifer in a dome structure. The concept storage development was prepared by National Grid Carbon as the storage solution for the Don Valley CCS project in 2009 and later switched to support the White Rose project. It is a large structure probably capable of holding around 500MT of CO_2 and so under plan conditions would not require any cluster developments for many years. There is however remaining uncertainty around reservoir quality and connectivity even after a successful appraisal well. An issue involving loss of injectivity due to reservoir quality remains a possible trigger for a cluster development. Such a large site will require a large cluster alternative and the nearby deeper Garrow gas field is unlikely to be large enough to accommodate the injection requirement. There are larger gasfields close by such as Ravenspurn (did not meet SSAP injectivity requirements due to low permeability).

A schematic location map for Endurance is shown in Figure 5-25 showing a 50km radius around the site. Cumulative CO_2 Stored capacity and cluster options are summarised in Figure 5-26 and Figure 5-27 where the more qualified sites with reference to the IEAGHG guidelines are represented by larger dots.

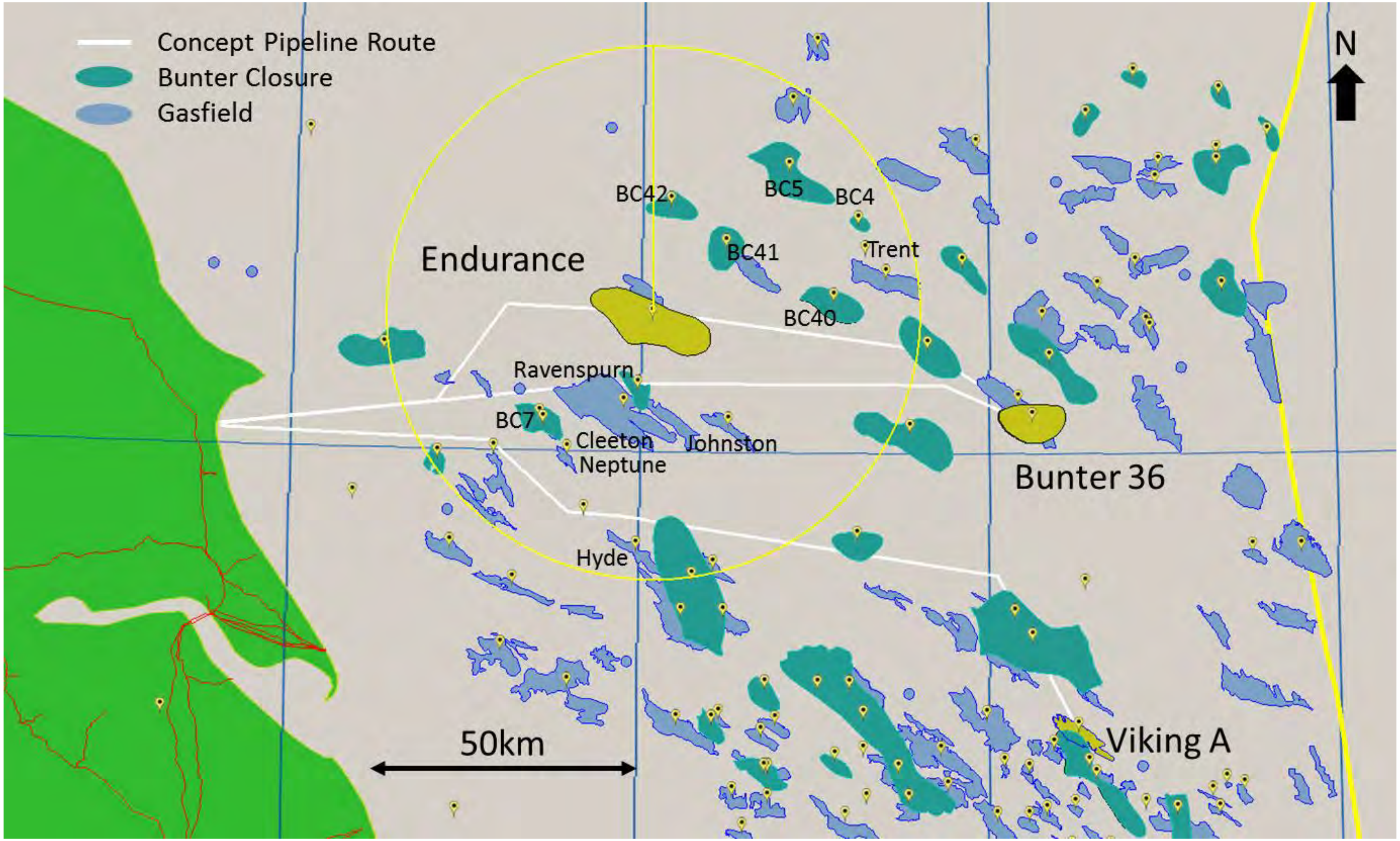

Figure 5-25 Endurance Location Schematic

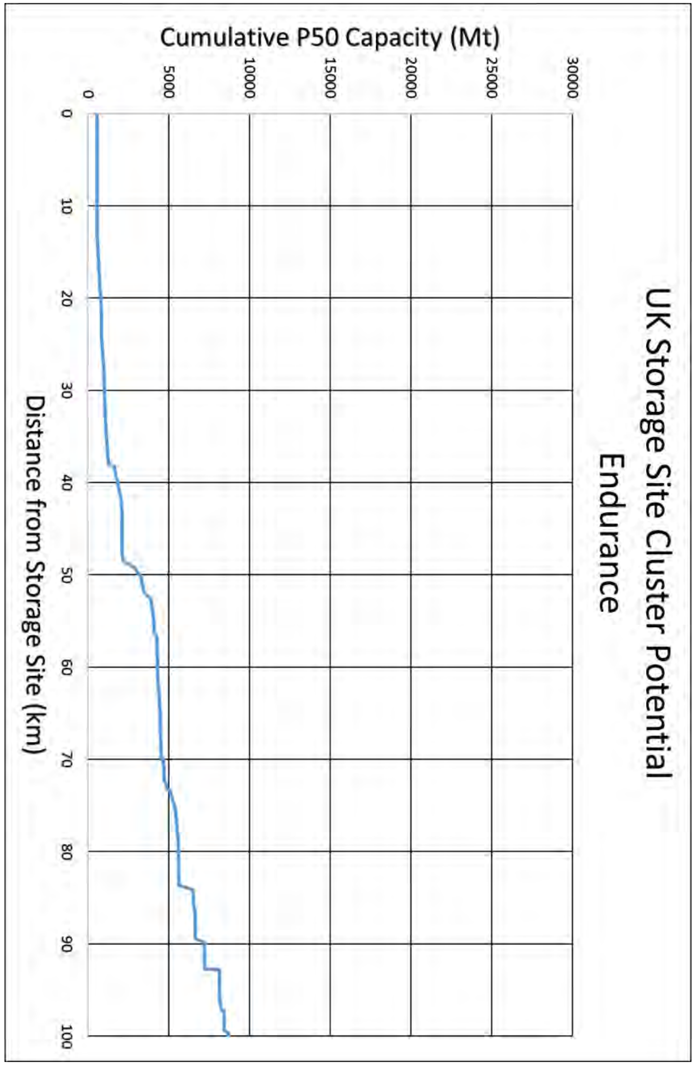

Figure 5-26 CO_2 Stored P50 Capacity within 100km of Endurance

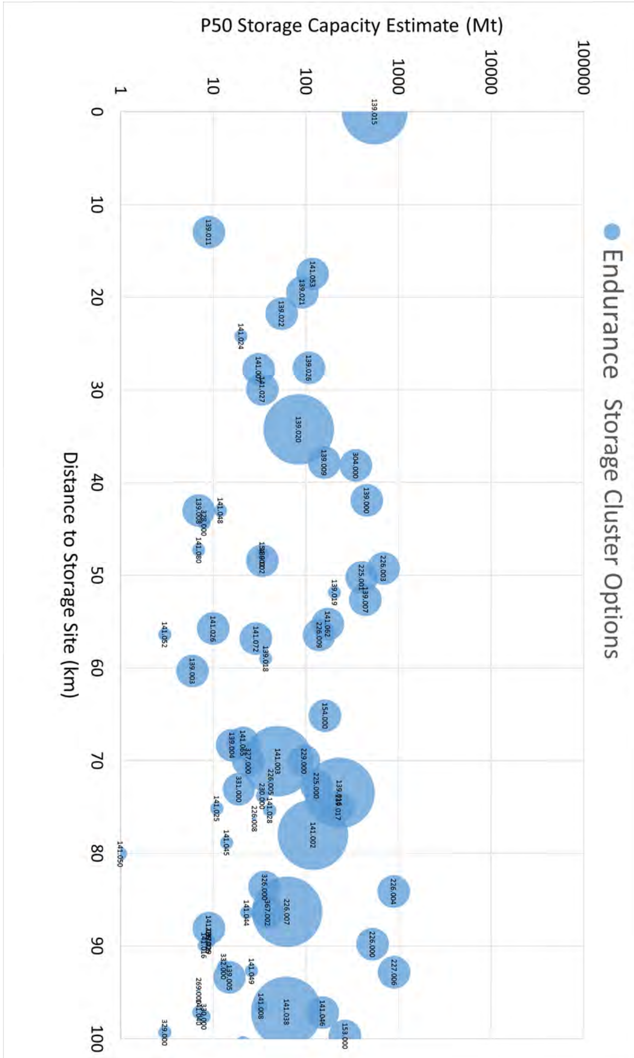

Figure 5-27 Storage Cluster Options within 100km of Endurance

Site	Type	CO_2Stored Ref.	P50 Capacity (CO_2Stored)	Qualification Score	Description & Comments
Bunter Closure 7	Saline Aquifer	139.011	9	6	A small sized Bunter Closure which is unlikely to be developed as a CO_2 Storage site
Ravenspurn gas field	Gas	141.053	119	6	A large sized Permian Leman gas field which could provide usable storage capacity. Excluded from further study in SSAP due to the low permeability (11mD)
Bunter Closure 41	Saline Aquifer	139.021	92	6	A modest sized Bunter Closure which could provide usable storage capacity
Bunter Closure 42	Saline Aquifer	139.022	55	6	A small sized Bunter Closure which is unlikely to be developed as a CO_2 Storage site
Johnston gas field	Gas	141.024	20	5	A small Permian Leman gas field unlikely to be developed as a CO_2 storage site
Bunter Closure 46	Saline Aquifer	139.026	108	6	A modest sized Bunter Closure which could provide usable storage capacity
Cleeton gas field	Gas	141.007	31	6	A small Permian Leman gas field unlikely to be developed as a CO_2 storage site
Neptune gas field	Gas	141.027	34	6	A small Permian Leman gas field unlikely to be developed as a CO_2 storage site
Bunter Closure 40	Saline Aquifer	139.020	84	7	A modest sized Bunter Closure which could provide usable storage capacity
Bunter Closure 5	Saline Aquifer	139.009	158	6	A modest sized Bunter Closure which could provide usable storage capacity
Bunter Sandstone Formation Zone 13	Saline Aquifer	304.000	347	6	A large open saline aquifer containing some closures
Bunter Sandstone Formation Zone 4	Saline Aquifer	139.000	456	6	A large open saline aquifer containing some closures
Hyde gas field	Gas	141.048	12	5	A small Permian Leman gas field unlikely to be developed as a CO_2 storage site
Bunter Closure 4	Saline Aquifer	139.008	7	6	An unusually small Bunter closure unlikely to be developed as a CO_2 storage site
Trent gas field	Gas	328.000	8	5	A small Carboniferous gas field unlikely to be developed as a CO_2 storage site

Table 5-8 Cluster Site Options for Endurance

5.4 Site Cluster Motivations

Four primary motivations have been identified that would encourage the addition of new injection sites near to an existing injection site using shared infrastructure.

- Augmentation
- Failure Mitigation
- Commercial Pressure
- EOR Potential

5.4.1 Augmentation

1. Further capacity required.
    a. The storage units for the approved capacity of the storage site have already been reserved and so further capacity is required to accommodate future demand.
2. Further injectivity required.
    a. Injectivity is maxed out and yet more is required. This would normally involve simply adding new wells but in some confined reservoirs this may not be sufficient.

5.4.2 Failure Mitigation

1. Falling Injectivity and/ or capacity estimate.
    a. Injectivity in the storage reservoir falls because of rapidly increasing reservoir pressure (eg Snohvit). Additional pore space access may therefore be required.
    b. Series of mechanical failures (eg SSVs or tubing collapses).
2. Integrity concern.
    a. Rising concerns over subsurface integrity cause injection to be reduced or even shut down requiring an alternative to be developed (InSalah).
    b. A regulatory instruction (competing use of subsurface / complaint from a petroleum operator etc).

5.4.3 Commercial Pressure

1. Competing storage provider B with lower cost offering than storage provider A.
    a. This motivation would require full deregulated open access to offshore transportation systems such that Provider A could not control the cost effectiveness of Provider B and therefore render it non-competitive. At Endurance for example it might be very difficult to buy storage from Storage Provider B if ullage existed in the Endurance Injectivity and storage potential and such incremental capability could be engineered on the platform.
2. A single storage operator considers that unit cost could be reduced for all by adding a second site.
3. Liability Management - Don't want anybody else's CO_2 in the store as it moves the site closer to the failure envelope (depends on whether emitter has the liability or the storage operator carries this).

5.4.4 EOR Potential

1. Enhanced oil recovery has been a potential driver for CCS in the UK for many years. A key challenge to data has been making the twin

commercial development decisions for a capture plant and an EOR development at the same time. This has proved too problematic so far even when oil prices were $140/bbl. Looking forward it is now likely that if EOR happens, it will follow CO_2 storage projects and so EOR sites may join a CO_2 storage anchor site as part of a cluster.

5.4.5 Assessment

An assessment of the likely relevance of each of the 8 motivations to each of the anchor sites is provided in Table 5-9 using a traffic light system.

- Red. Not relevant, unlikely.
- Amber. May be relevant.
- Green. Highly relevant, most likely.

Storage Anchor Site	A1 Capacity Augmentation	A2 Injection Augmentation	B1 Falling Injectivity	B2 Integrity Concerns	C1 Competitive Position	C2 Economies of Scale	C3 Liability Management	D1 EOR Potential
Viking A	Bunter Closure 3							
Goldeneye	CaptainX							
Captain X	Goldeneye							
Forties 5 Site 1	Forties 5							
Hewett	Bunter Closure 9/ Leman							
Endurance	Bunter Closure 5 / Ravenspurn							
Bunter 36	Bunter Closure1, 37							
Hamilton	S Morecambe							

Table 5-9 Anchor Site Motivations for Clustering

5.5 Most Likely Cluster Scenario Developments

5.5.1 Viking A

A cluster development catalysed from the 130MT Viking A anchor store could involve either sites along the pipeline corridor subject to its course or sites close to Viking A such as Bunter Closure 3. A key working assumption is that the pipeline size would be chosen to meet the supply requirement and that no pre-investment in significant over-sizing is likely.

The current assumption is for a CO_2 supply rate of 5MT/y. In which case Viking A would have a useful life of approximately 26 years, up to 24 years or so less than a typical large scale thermal power plat would require. In this situation it would be sensible to appraise additional storage capacity in the vicinity of the Viking A installation (such as Bunter Closure 3) during the development of the anchor site. Bunter Closure 3 could augment storage capacity by up to 230MT (CO_2Stored), would reduce the risk of systemic failure and, given its proximity to Viking A, have the potential to be operated by the same company. This would enable the transition from the anchor store to cluster development to be managed optimally and ensure that operational synergies are maximised.

Such a cluster development would likely be able to store up to 360MT of CO_2 over a 50-year period subject to infrastructure lifespan. Further upside is available locally across the Viking Gas field complex, but may be more challenged with injectivity issues because of lower reservoir quality in the deeper reservoirs. The most likely cluster development at Viking A would be triggered by underperformance of injection perhaps linked to the transition from gas to dense phase operation. In this case, injection into the shallower Bunter reservoir of Closure 3 might offer a useful and practical alternative.

5.5.2 Bunter Closure 36

Bunter 36 represents an excellent anchor site and starting point for CO_2 storage in Bunter Closures. The planned development has been configured to deliver a 7MT/yr supply from the Humberside area over an operational life of 40 years. If the project performed as expected then the infrastructure would be at the end of its design life after 40 years and so new infrastructure of pipeline and platform would likely be required. However, if the project performed below expectation in terms of injectivity for some reason then alternative sites are available locally that could be developed with short subsea tiebacks to Bunter Closure 37 or Bunter Closure 1. Short term issues with performance might be managed in part through the injection into the depleted underlying Schooner gas field, although the capacity here is very limited. The most likely trigger for a cluster development out of Bunter Closure 36 is the potential underperformance of the site with regards to injection. If this is a result of reservoir issues, then cluster developments might be limited since most of the larger nearby storage targets are also Bunter Closures with very similar reservoir characteristics.

5.5.3 Hamilton

A cluster development catalysed from the 125MT Hamilton anchor store could involve either (or both) the South or North Morecambe sites as clusters. These are both very large depleted gas fields, 15 – 30km north of Hamilton and with storage capacities estimated to be 850MT and 180MT respectively.

Given that the Morecambe sites are significantly larger than Hamilton and therefore likely to have a greater asset life, it seems likely that they would require bespoke infrastructure to develop either of them fully. The conceptual development for Hamilton includes a new 16” diameter pipeline to transport 5MT/y of CO_2. It is conceivable that this pipeline could also be used as part of an initial phase of a South Morecambe development. However, given that an extension pipeline would be required from the Hamilton platform it would almost certainly be cheaper and operationally simpler to install a dedicated pipeline to South Morecambe subject to the requirements of the local industry. The most likely trigger for a cluster development from Hamilton is considered to be operational issues on the site perhaps linked to the change from gas to dense phase operation. Cluster options at this time might involve the small site at Hamilton North or the much beiger site at South Morecambe if that were free from hydrocarbon operations.

5.5.4 Hewett

Hewett is a very depleted gas field in the Southern North Sea and was the subject of a detailed CO_2 Storage FEED study in 2011 to support the Kingsnorth CCS project. Storage capacity is held in an upper and lower Bunter Sandstone reservoir and comprises over 200MT with considerable upside potential beyond 300MT. With such a large storage site operational, a huge and rapid build out of CCS infrastructure would be required to demand further capacity access in the short to medium term. The most likely trigger for a cluster development in that timeframe from Hewett would result from issues associated with containment linked to legacy oil and gas well penetrations of which there are many on the site. The obvious targets for such a development would include the Leman gas field once its production life has finished, and also the large Bunter Closure 9 above the Leman gas field.

5.5.5 Endurance

Endurance is a saline aquifer reservoir located within a structural dome closure and was the target storage site for the White Rose project. It was selected by National Grid after a careful screening study which looked for a large site which could be developed with minimum interaction with oil and gas operations so as to avoid any subsurface conflicts. Endurance is estimated to host an ultimate capacity of over 500MT and have a good quality reservoir where injection can be scaled by adding more injection wells. With such a site operational the key question might be why consider anywhere else? since the site could potentially accept 10MT/yr for 50 years. The key trigger for clustering further sites would be around risk mitigation on operational performance arising from the residual subsurface uncertainties in reservoir characterisation. In line with Bunter Closure 36, there are other adjacent Bunter closures close by (Bunter Closure 5) which might provide contingent capacity security, however if the operational issue was linked to underperformance arising from subsurface geology then it may be necessary to target the deeper Permian reservoirs in nearby depleted gas fields such as Ravenspurn. The nearby Carboniferous Garrow gas field is likely too small to be able to serve as a useful contingent storage site for Endurance.

5.5.6 Goldeneye

Goldeneye is perhaps the most studied offshore CO_2 storage site not yet in operation and has been the subject of two FEED studies in 2011 and also in 2014. A depleted gas field with a strong and active aquifer has left reservoir pressures much higher than with sites like Hamilton or Viking A. Whilst the site has excellent characteristics, its storage capacity is limited by the small size of the closure with ultimate capacity estimated to be 20-30MT. Cluster development is therefore most likely to be driven by the requirement to augment capacity in the short to mid term. There are several subsurface targets that could contribute to this including Captain X, the water bearing sandstone underlying the Goldeneye gas field and the overlying Mey sandstone open saline aquifer. As long as the Captain Sandstone performs as anticipated then the most likely step out point is likely to be Captain X with a subsea tie back. Accessing the underlying Captain aquifer from the Goldeneye platform is more problematic since the existing well stock is not deep enough and use of the aquifer space from overfilling the Goldeneye trap will result in exceptionally low storage efficiency and create integrity concerns. Finally, a key consideration is the design life of the Goldeneye platform will be exceeded by mid-2020's and new infrastructure may be required anyway.

5.5.7 Captain X

Captain X is a hybrid saline aquifer storage site with both depleted gas field and open saline aquifer elements. It has much in common with Goldeneye, but is designed to exploit the saline aquifer pore space within the site. Key issues with Captain X are related to CO_2 plume mobility and it is the uncertainty associated with this that is the most likely trigger for a cluster development. Cluster development options could to the Goldeneye storage site either via a subsea tie back to the existing platform or more likely to a new subsea injection system. Other key options include the deployment of CO_2 as an agent for enhanced oil recovery in both Buzzard and Golden Eagle. For such an EOR application, CO_2 supply rates would have to exceed 2MT/yr to be viable.

5.5.8 Forties 5 Site 1

Forties 5 Site 1 is a very large open aquifer system in the central part of the North Sea. This site is further from landfall than any others considered in the ETI study and is already designed as a cluster development incorporating twin plume placements in a staged development from a platform and connected subsea site. Such a step out and tie back strategy could be extended for as long as the central platform and pipeline infrastructure could service injection needs. The Forties 5 saline aquifer is much larger than just site 1 and there are many options to the north and west of site 1 where further injection sites could be established. It should however be noted that the development as described in the ETI study would inject 8MT/yr for almost 40 years and that at the end of this time the pipeline and platform infrastructure would be at the end of its design life such that it would need to be replaced before injection could continue.

5.6 Insights from Clustering Considerations

There are three primary motivations for site clustering: -

1. Low capacity or storage efficiency - The anchor site is too small or its storage efficiency is very low such that large step outs are required such as outlined with the Forties 5 Site 1 development.
2. Site underperformance - The anchor site underperforms and cluster sites are developed to manage or mitigate risk.
3. The cluster is specifically designed as EOR ready where injection into a storage site can be halted when CO_2 is required by an adjacent oilfield for enhanced oil recovery.

Oversizing a pipeline to a small consented storage site makes little sense and would only occur in a scenario where the pipeline was re-used after hydrocarbon service (such as Goldeneye).

A right sized pipeline (for the store) to a large initial storage site (such as Endurance) with moderate storage efficiencies (>20%) does not lend itself to cluster developments under normal performance conditions, however cluster planning is of heightened importance as the consequences of loss of injectivity with such large inventories of CO_2 are likely to be commercially significant. Once a large site such as Endurance is near to being filled to capacity, perhaps after 50 years of injection, the infrastructure will need replacing and probably could not be used for further cluster development.

Cluster developments are perhaps the only way to progress open saline aquifers with low storage efficiencies. These sites are likely to occupy large areas that cannot be developed from a single drill centre.

5.6.1 Further Work Required

Since the motivation required for cluster developments is largely restricted to risk mitigation, cluster development concepts should be developed for each site as a part of the forward storage development plan and included in the injection permit application. Once a full risk assessment has been completed then there may be specific measures that could be taken on a case by case basis which might need to be costed into the primary development such as:

- Additional slots on a platform
- Pre-install T pieces along the pipeline

Storage clusters will be required in sites where storage efficiencies are low such as in open saline aquifers. Here more work is required around optimising storage efficiency through reservoir development as this will control the timing and requirement of cluster developments from these sites.

With so much discussion in CCS centred around the benefits of clustering, some outreach work is required to clarify the role and challenges of clusters for offshore storage and why clustering of onshore CO_2 sources is very different from clustering of offshore storage.

The requirements for permit applications and lease agreements was established during FEED of the commercialisation programme and tested by two rather unique storage sites. These guidelines should now be tested and updated to accommodate the broader learnings from the 3 UK FEED storage sites and five Strategic UK Storage Appraisal Portfolio sites to ensure that they continue to be fit for purpose.

Future EOR projects will benefit significantly from a local CO_2 storage site within the cluster to manage the optimal supply of CO_2 to the field. It is recommended that a short analysis be completed to characterise how this optimal supply might be managed through the life of a cluster. This could be achieved by using type curves for CO_2 EOR performance (incremental recovery vs cumulative miscible injectant volume and cumulative CO_2 injected vs cumulative CO_2 back produced) to model the operational demands of the oilfield on the operational requirements of the storage site. This will establish and confirm the value of developing a storage site to be ready to serve alongside an EOR project or be “EOR Ready”. It is important that such a project is characterised from existing and extensive CO_2EOR modelling work on North Sea Fields rather than on the use of West Texas analogues.

6.0 References

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Energy Technologies Institute. (2016). *Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource.* Pale Blue Dot Energy Ltd.

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7.0 Appendices

Appendices are supplied separately as individual files.

7.1 Appendix 1 – Hamilton Gas Phase Operations Without Heating

7.2 Appendix 2 – Endurance Cost Estimate (SSAP)

7.3 Appendix 3 – Endurance Cost Estimate (SSAP*)

7.4 Appendix 4 – Minimum Viable Development Plans

7.5 Appendix 5 – Viking A Minimum Development Plan Cost Estimate

7.6 Appendix 6 – Captain X Minimum Development Plan Cost Estimate

7.7 Appendix 7 – Hamilton Minimum Development Plan Cost Estimate

7.8 Appendix 8 – Forties 5, Site 1 Minimum Development Plan Cost Estimate

7.9 Appendix 9 – Bunter Closure 36 Minimum Development Plan Cost Estimate

7.10 Appendix 10 – Bunter Closure 36 Minimum Development Plan Plus Cost Estimate

ETI

Strategic UK CCS Storage Appraisal – Hamilton Development – Gas Phase Operation without Heating – Process Calculations

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Strategic UK CCS Storage Appraisal

Hamilton Development – Gas Phase Operation without Heating – Process Calculations

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CONTENTS

ABBREVIATIONS

The following abbreviations are used throughout this document:

BHP	Bottom Hole Pressure
CCS	Carbon Capture & Storage
CH_4	Methane
COP	Cessation of Production
CO_2	Carbon Dioxide
CRA	Corrosion Resistant Alloy
DTS	Distributed Temperature Sensing
EISB	East Irish Sea Basin
ETI	Energy Technologies Institute
HPU	Hydraulic Power Unit
HVAC	Heating, Ventilation & Air Conditioning
HVDC	High Voltage Direct Current
MAOP	Maximum Allowable Operating Pressure
MCS	Master Control Station
MD	Measured Depth
MSL	Mean Sea Level
Mtpa	Million Tonnes per Annum
MWg	Megawatts Gross
NIST	National Institute of Standards & Technology
NUI	Normally Unmanned Installation
N_2	Nitrogen
OSI	Offshore Storage Installation
OSPAR	(Oslo-Paris) Convention for the Protection of the Marine Environment of the North-East Atlantic
PDHG	Permanent Downhole Gauge
PFD	Process Flow Diagram
P-i-P	Pipe-in-Pipe
POA	Point of Ayr
PVT	Pressure-Volume-Temperature
SUKSAP	Strategic UK Storage Appraisal Project
TBC	To Be Confirmed
TRSSSV	Tubing Retrievable Sub-Surface Safety Valve
TVDSS	True Vertical Depth Subsea
UKCS	United Kingdom Continental Shelf
UTM	Universal Transverse Mercator
VLE	Vapour-Liquid Equilibrium
VSAT	Very-Small-Aperture Terminal

1 INTRODUCTION

1.1 SUKSAP Development Plan Overview

The Strategic UK Storage Appraisal Project (SUKSAP) appraised the Hamilton site as a possible store for Carbon Dioxide (CO_2) and a Field Development Plan was developed (ref. [8]).

The depleted gas reservoir in the East Irish Sea was seen as a strategic development in terms of its locality, injectivity, storage capacity, and its reservoir characteristics. However, due to its low initial pressure conditions in the depleted gas reservoir, a solution which required offshore heating was proposed. This enabled the site to achieve its 5 Mtpa CO_2 supply requirement and maximise the storage capacity, but there was a CAPEX and OPEX impact associated with the provision of the heating.

The proposed development plan consisted of a new 26 km, 16 inch pipeline from Point of Ayr (POA) running in liquid / dense phase to a new normally unmanned installation (NUI) near to the existing Hamilton platform. The NUI consisted of 2 gas injection wells initially (plus 1 spare gas injection well), with 2 further well drilled after 15 years or so for liquid CO_2 injection once the reservoir conditions would facilitate liquid injection.

The operating philosophy was:

1. Gas Phase
    a. Liquid phase in the pipeline, heated on arrival at the NUI to allow injection as gas phase, avoiding low temperature conditions in the well.
2. Transition Phase
    a. Liquid phase in the pipeline, heated on arrival at the NUI to above the critical temperature. Injection of dense phase CO_2 into the gas injector wells. An artificial membrane at the sand face results in phase transition at a distance from the bottom hole.
3. Dense Phase
    a. Dense phase in the pipeline, injected into new dense phase wells. Heating only needed during re-starts.

1.2 Purpose of this Technical Note

The purpose of this technical note is to present the results of an initial high-level steady-state flow assurance review of the Hamilton CCS project.

Specifically, this technical note attempts to answer the following questions:

1. Is a development option without any heating of the CO_2 feasible?
2. If so, what would such a development option look like?

1.3 Hamilton

The Hamilton field is located in the East Irish Sea Basin (EISB), in UKCS block 110/13a, approximately 23 km from the Lancashire coast, due West of the town of Formby in Merseyside. There are four gas producing wells in the Hamilton field, designated 110/13-H1 to H4.

The ENI operated Hamilton Platform is a Normally Unmanned Installation (NUI), which sits in approximately 34 m depth of water. The Hamilton NUI produces gas which is exported to the Liverpool Bay pipeline system via a 20 inch, circa 11.5 km subsea pipeline to the nearby Douglas Complex. (ref. [2])

Figure 1.1 shows the Hamilton NUI.

Figure 1.1 – Hamilton NUI (ref. [5])

The Douglas Complex, also operated by ENI, is located circa 9 km West-southwest of Hamilton and lies in approximately 29 m water depth. Douglas comprises three bridge-linked platforms: a wellhead platform (DW), a production platform (DP), and an accommodation jackup (DA). (ref. [2][4])

Douglas gas production ties-back to the Point of Ayr (POA) Gas Terminal in North Wales via a 32.2 km, 20 inch subsea pipeline. (ref. [2][3])

The stabilised export crude oil from Douglas is piped 17 km North, via a 14 inch oil export line, to the Offshore Storage Installation (OSI), a purpose built barge with circa 860,000 bbls storage capacity, from where it is offloaded by tanker. (ref. [4])

Figure 1.2 shows the location of the Hamilton field and the Liverpool Bay pipeline system within the East Irish Sea Basin (EISB).

Figure 1.2 – Location of Hamilton in the EISB, UKCS Block 110/13a (ref. [2])

The Hamilton field has been identified as a potential storage location for up to 5 million tonnes of CO_2 per annum, as part of a Carbon Capture & Storage (CCS) scheme.

2 BASIS

2.1 Composition

For the purposes of this technical note the composition of the CO_2 stream is considered to be 100% pure CO_2, except in cases where it has been artificially modified with certain proportions of either nitrogen (N_2) or methane (CH_4) to mitigate low temperature issues.

In reality, the fluid will contain trace quantities of other gases / contaminants, such as nitrogen, oxygen, water vapour, etc.

2.1.1 Compositions from Similar Developments

Table 2.1 details some CO_2 stream compositions from similar development schemes for reference.

Component	mol% (% v/v)		
	Kingsnorth (ref. [1])	Peterhead / Goldeneye (ref. [6])	White Rose (ref. [7])
CO_2	99.94	99.0	99.700
H_2	-	≤ 0.3	-
N_2	< 0.035	≤ 1.0 ($H_2 + N_2 + Ar$)	0.226
Ar	-		0.068
O_2	< 0.015	-	0.001
H_2O	0.010	-	0.005

Table 2.1 – CO_2 Composition for Planned Similar Developments

2.2 PVT Characteristics

The PVT properties were taken from the Pale Blue Dot Hamilton Storage Development Plan (ref. [8]), in which they were modelled using the Peng Robinson equation of state and the CO_2 density correction within the Petroleum Experts software package for modelling CO_2 injection.

The injection fluid was modelled as 100% CO_2.

The PVT description used in the Hamilton Storage Development Plan (ref. [8]) is shown in Table 2.2, alongside the same properties as predicted by HYSYS using the Peng Robinson equation of state. HYSYS predicted very similar figures to those presented in the Storage Development Plan.

Property	Value		Units
	Storage Development Plan (ref. [8])	HYSYS	
Critical Temperature	30.98	30.95	°C
Critical Pressure	73.77	73.70	bara
Critical Volume	0.0939	0.0939	m^3/kg.mole
Acentric Factor	0.239	0.239	-
Molecular Weight	44.01	44.01	g/mol
Specific Gravity [Note 1]	1.53	1.50	-
Boiling Point	-78.45	-78.55	°C

Table 2.2 – PVT Properties (ref. [8])

Notes:

1. HYSYS specific gravity at 1 atm and 20 °C. Conditions from Storage Development Plan not stated.

2.2.1 CO_2 P-T Diagram

Figure 2.1 below shows the P-T diagram for pure CO_2.

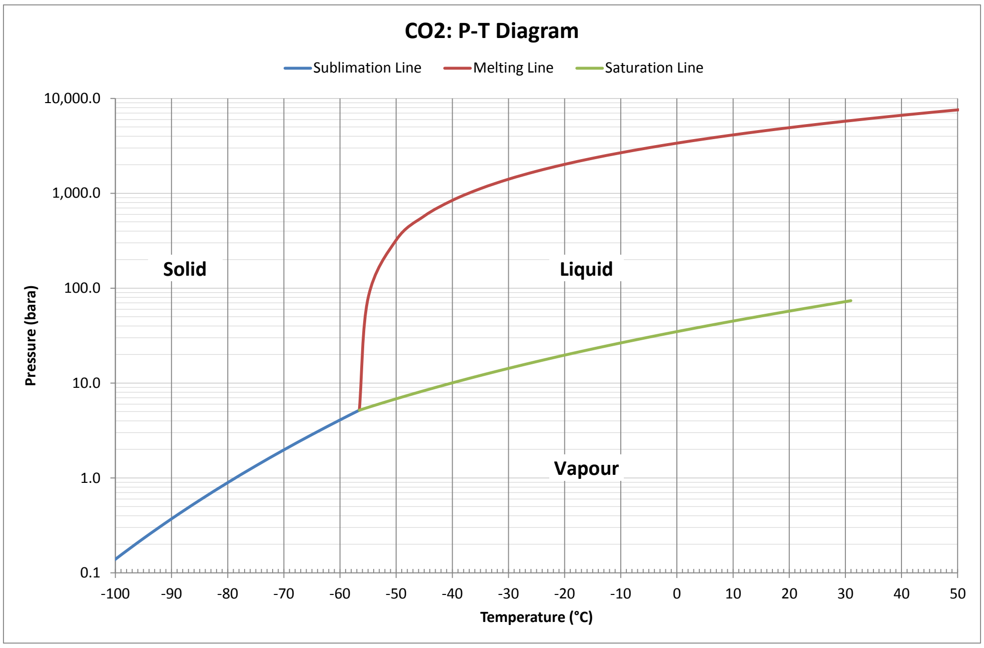

Figure 2.1 – P-T Diagram for Pure CO_2

A more detailed P-T diagram covering the range -60 to 40 °C and 0 to 80 bara is shown in Figure 2.2.

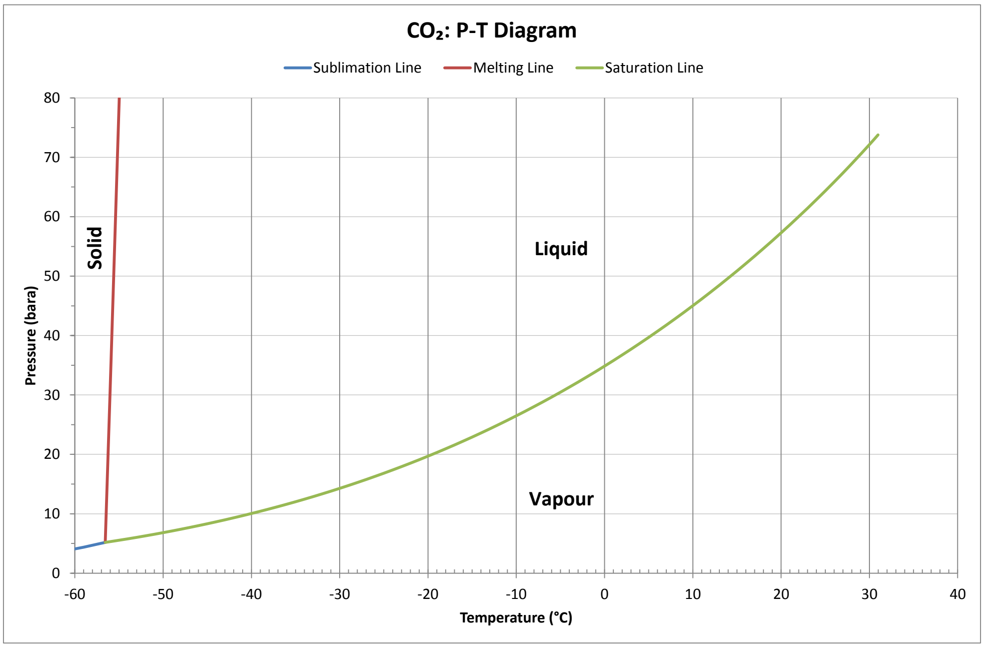

Figure 2.2 – P-T Diagram for Pure CO_2 (detail)

2.3 Facilities Overview

A process flow diagram (PFD) of the Hamilton development (with heating) taken from the Hamilton Storage Development Plan (ref. [8]) is presented in Figure 2.3 below.

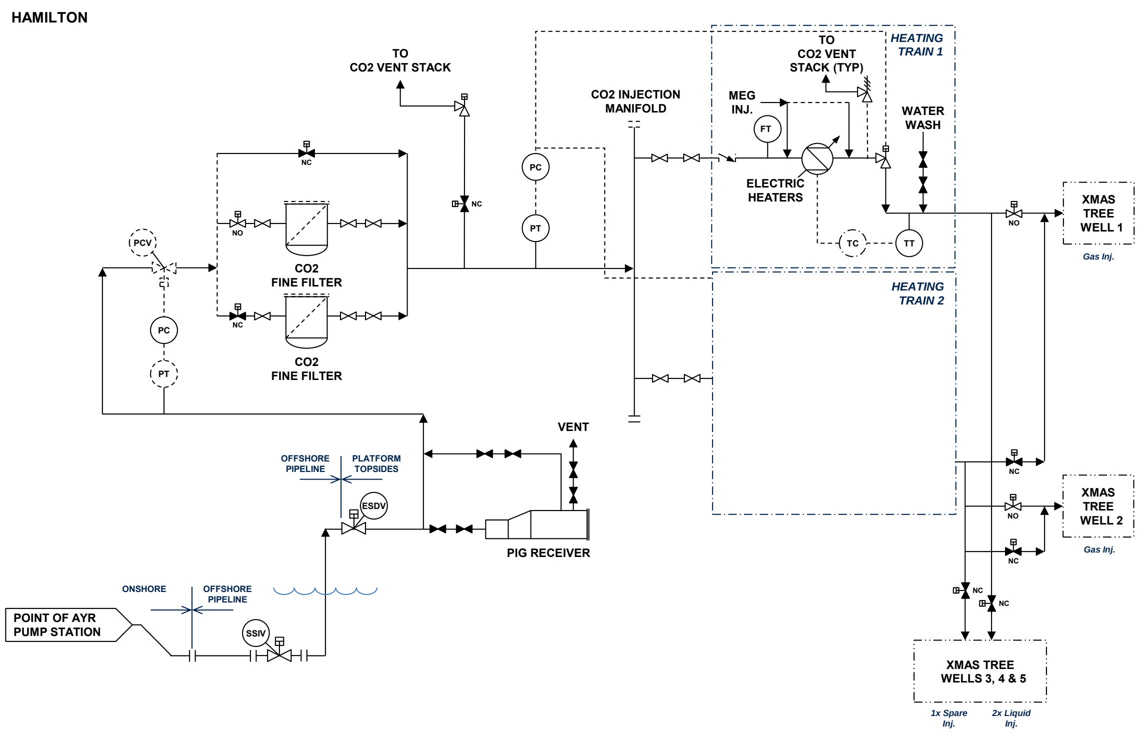

Figure 2.3 – Hamilton PFD (ref. [8])

Note: The above PFD includes provision of offshore electric heaters. The intention of this technical note is to investigate the potential for this development without necessitating these heaters.

2.3.1 Onshore Facilities

The onshore facility for the CO_2 Transport System takes compressed and cooled CO_2 from the carbon capture plant and directs the fluid to the onshore pipeline for transportation to the offshore facility.

The base case for the onshore facility for the CO_2 Transport System includes an onshore meter, which is used for fiscal metering of the CO_2 and for leak detection purposes.

An onshore permanent pig launcher is also provided for initial system commissioning, pipeline inspection, and for sweeping the CO_2 from the pipeline system into the reservoir.

An onshore blowdown facility is provided for venting and dispersing CO_2.

It has been assumed that the Point of Ayr pump station delivers a pressure of up to 115 barg. (ref. [8])

2.3.2 Subsea Transmission Pipeline

The existing 20 inch gas export pipeline from Hamilton to Douglas is circa 11.5 km long. (ref. [2]). The existing 20 inch gas export pipeline from Douglas to the Point of Ayr (POA) Gas Terminal in North Wales is 32.2 km long. (ref. [2][3])

By COP (Cessation of Production), the Hamilton field will have been in production for 20+ years. It is assumed in this study that the existing infrastructure will not be suitable for re-use for liquid phase operation. Therefore, in the original Development Plan (ref. [8]) it was assumed that a new CO_2 pipeline would be laid for this project.

For gas-phase operation, which is anticipated to be feasible for only the first few years of CO_2 injection operations, it may be possible to re-use the existing hydrocarbon gas export pipeline route from Hamilton, via Douglas.

Both pipeline options (new and existing) are considered in this Technical Note.

The proposed pipeline routing for the new CO_2 injection flowline is discussed in the Hamilton Storage Development Plan (ref. [8]) and is shown in orange in Figure 2.4 below.

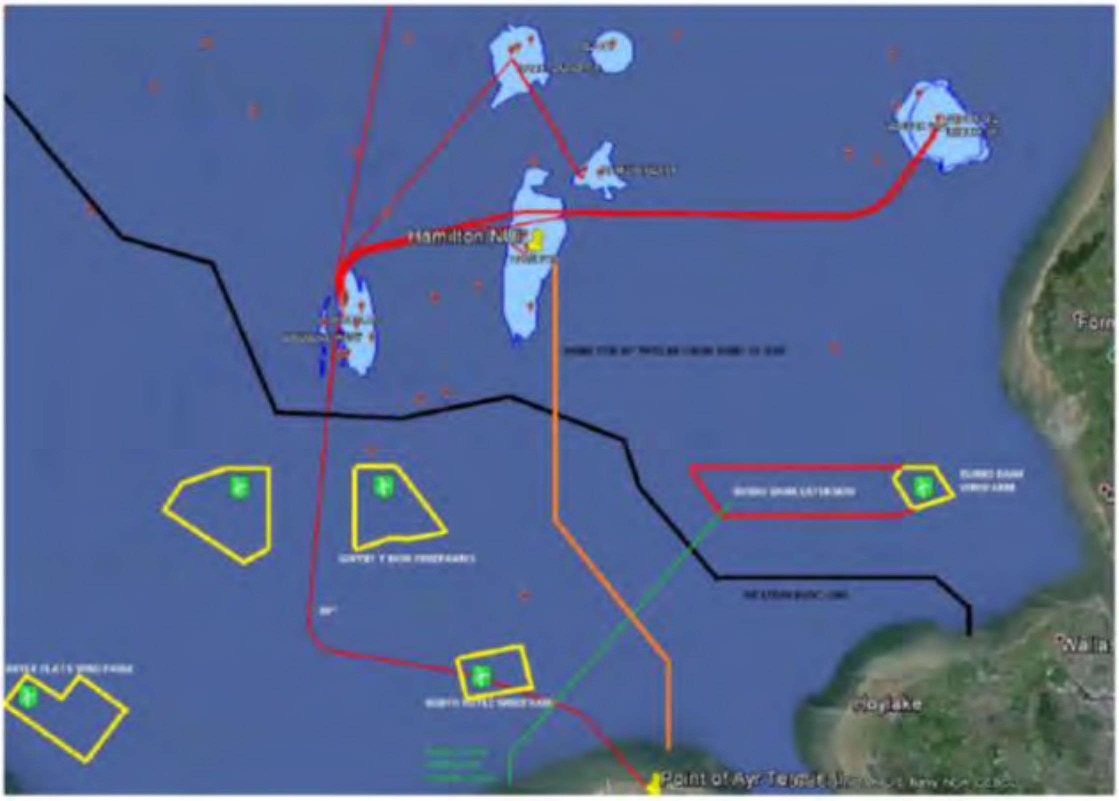

Figure 2.4 – Proposed CO_2 Injection Pipeline Routing (ref. [8])

The proposed new pipeline route length is 26 km.

The direct pipeline route from POA to Hamilton has been selected to minimise the pipeline route length while avoiding existing facilities (Windfarms, Douglas Complex, etc.) and maintaining appropriate crossing angles.

The pipeline route shown does not cross any existing pipelines, but does cross the Western HVDC Link power cable, and may cross the Burbo Bank Extension power cable should that project proceed.

The pipeline will be taken offshore using either a cofferdam constructed on the beach/subtidal area, or using a caisson (which can be constructed entirely sub-tidally).

Due to the shallow water depth throughout the Liverpool Bay (< 30 m) it is recommended that the pipeline will be trenched and buried throughout (with the exception of crossings which will need protection in the form of concrete mattresses or rock dump). (ref. [8])

2.3.3 Risers

At the time of writing, no riser details were available.

For the purposes of this technical note a vertical riser has been assumed.

It is also assumed that the riser diameter is the same as that of the subsea pipeline; and that the riser ESDV is located at an elevation of 34 m MSL.

The Hamilton NUI lies in approximately 25 m water depth (ref. [9]), therefore the riser length is taken to be 34 + 25 = 59 m.

2.3.4 Offshore Topsides Facilities

The existing Hamilton Platform is a Normally Unmanned Installation (NUI), which sits in approximately 25 m depth of water at the following location:

Platform	UTM Coordinates			Longitude	Latitude
	Easting (m)	Northing (m)	UTM Zone		
Hamilton NUI (existing)	470001	5935421	30U	-3.4529617	53.56681

Table 2.3 – Existing Hamilton Platform Location (ref. [2][9])

The Hamilton Storage Development Plan (ref. [8]) gives slightly different coordinates for the new Hamilton NUI for CO_2 injection than those shown in Table 2.3 for the existing platform, stating that the optimum position has been determined through drilling studies:

Platform	UTM Coordinates			Longitude	Latitude
	Easting (m)	Northing (m)	UTM Zone		
Hamilton NUI (new)	470200	5935400	30U	-3.449959	53.566625

Table 2.4 – New Hamilton Platform Location (ref. [8])

2.3.4.1 Topsides Design

The Installation topsides are proposed to be constructed as a single lift topsides module. A multi-level topsides module consisting of a Weather Deck, a Mid-Level, a lower Cellar Deck and a cantilevered Helideck has been assumed.

The Weather Deck will be of solid construction to act as a roof for the lower decks; it will provide a laydown area for the crane and house the HVAC package and VSAT domes. A Helideck will be cantilevered out over the Weather Deck.

The Mid-Level Deck will only partially cover the topsides footprint and will serve to house the manifolding pipework and Pig Receiver.

The Cellar Deck will house the Wellhead Xmas Trees and associated piping, a Master Control Station (MCS), Hydraulic Power Unit (HPU), process equipment, including CO_2 heaters, emergency power generation package, chemical and diesel tanks, Control and Equipment Room and short stay accommodation unit. (ref. [8])

2.3.4.2 Topsides Process

The primary Platform Injection facilities will consist of:

- a topsides Emergency Shutdown Valve (ESDV)
- a pressure control valve (PSV), which will serve to safeguard the pipeline pressure and maintain the CO_2 in the pipeline in liquid phase
- Fines Filters, that will prevent solid contaminates entering the injection well bores
- a vent stack, to enable blowdown of the topsides pipework for maintenance
- an injection manifold, which will facilitate injection of the CO_2 to the respective wells

Topsides pig receiving facilities will also be provided to enable periodic pipeline integrity monitoring; there is no foreseen requirement for operational pigging.

All the topsides process pipework will use low temperature stainless steel materials in the event that a low pressure event occurs (i.e. venting).

Note: The facilities described here are for a non-heated gas-phase operation only option, not for the original SUKSAP project design set out in the Storage Development Plan (ref. [8]).

2.3.4.3 Power

A power cable will provide electrical power to the Hamilton NUI from the Point of Ayr. (ref. [8])

2.3.5 Wells

2.3.5.1 Existing Gas Producing Wells

There are at present four gas producing wells in the Hamilton field, designated 110/13-H1 to H4. Table 2.5 and Table 2.6 below give details of the Hamilton wells positions and depths.

Well	UTM Coordinates			Longitude	Latitude
	Easting (m)	Northing (m)	UTM Zone		
110/13-H1	469996	5935427	30U	-3.4530389	53.5668555
110/13-H2	469998	5935429		-3.4530111	53.566872
110/13-H3	469994	5935425		-3.4530667	53.566839
110/13-H4	469996	5935423		-3.4530389	53.5668222

Table 2.5 – Existing Hamilton Gas Producing Wells Locations (ref. [2])

Well	Water Depth (m MSL)	MD (m)	TVDSS (m)
110/13-H1	45.1	1677	1057
110/13-H2	45.7	2379	935
110/13-H3	45.7	1617	1084
110/13-H4	45.7	2333	929

Table 2.6 – Existing Hamilton Gas Producing Wells Depths (ref. [2])

By COP (Cessation of Production), the Hamilton field will have been in production for 20+ years.

2.3.5.2 New CO_2 Injection Wells

The Hamilton Storage Development Plan (ref. [8]) states that two operational wells are required to inject the anticipated 5 million tonnes per year of supplied CO_2. A back-up well is included within the drilling plan to provide a degree of redundancy.

Well and platform placement is therefore independent of existing facilities. However, with 4 long-term producing wells having been situated in the West of the structure, it is considered best practice to take advantage of the reduction in geological risk offered by the data from these wells, by siting the new wells in this area. (ref. [8])

The Hamilton Storage Development Plan (ref. [8]) discusses possible locations considered for the new CO_2 injector wells and proposes the following:

Well	UTM Coordinates			Longitude	Latitude
	Easting (m)	Northing (m)	UTM Zone		
INJ1 (gas)	469700.0	5936010.6	30U	-3.457568	53.572084
INJ2 (gas)	470700.0	5936169.3		-3.442482	53.573567
INJ3 (dense)	469607.7	5934700.0		-3.458834	53.560299
INJ4 (dense)	469726.9	5935800.0		-3.457141	53.570193

Table 2.7 – New Hamilton CO_2 Injection Wells Locations (ref. [8])

Well	TVDSS (m)
INJ1 (gas)	736.7
INJ2 (gas)	751.5
INJ3 (dense)	723.5
INJ4 (dense)	741.9

Table 2.8 – New Hamilton CO_2 Injection Wells TVDSS (ref. [8])

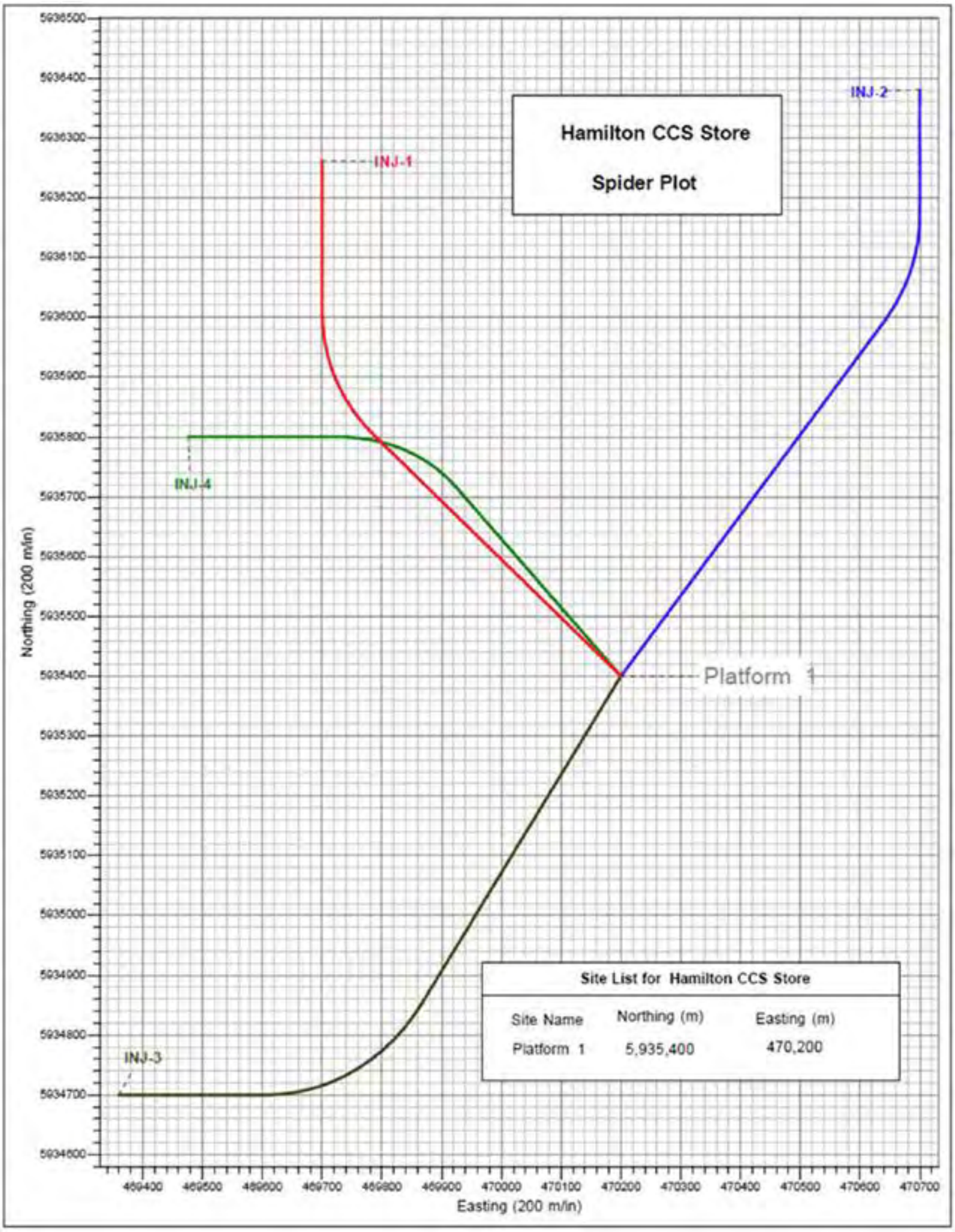

Figure 2.5 – Well Directional Spider Plot (ref. [8])

Directional profiles have been prepared for all four wells and can be found in the Hamilton Storage Development Plan (ref. [8]).

For the purposes of this technical note the gas-phase CO_2 injection wells are assumed to be vertical (i.e. MD = TVD).

2.3.5.3 Pressure & Temperature Limitations

Some pressure and temperature limits on gas phase injection operations have been defined and are summarised in Table 2.9 below.

Parameter	Value	Units
Fracture Limit at Top of Perforations Depth (Depleted)	64.5 (935)	bara (psia)
MAOP [Note 1]	58 (841)	bara (psia)
Minimum Fluid Temperature at Perforation Depth	0	°C

Table 2.9 – Injection Pressure & Temperature Limits (ref. [8])

Notes:

1. The safe operating envelope for the wells is based on geomechanical analysis and the maximum allowable pressures have been constrained to 90% of the fracture pressures, i.e. 58 bara (841 psia) for the gas phase operation. (ref. [8])

2.3.5.4 Tubing Details

Well performance modelling was used to identify the optimal tubing size and assess some of the factors that may influence well injection performance. The results of this work are provided in the Hamilton Storage Development Plan (ref. [8]).

In summary, for gas phase operation, the upper completion consists of a 9 ⅝" tubing string, anchored at depth by a production packer in the 13 ⅜" production casing, just above the 9 ⅝" liner hanger.

Components include:

1. 9 ⅝" 13Cr tubing (weight TBC with tubing stress analysis work) with higher grade CRA from Barrier Valve to tailpipe
2. Tubing Retrievable Sub Surface Safety Valve (TRSSSV)
3. Deep Set Surface-controlled Tubing-Retrievable Isolation Barrier Valve (wireline retrievable, if available)
4. Permanent Downhole Gauge (PDHG) for pressure and temperature above the production packer
5. Optional DTS (Distributed Temperature Sensing) installation
6. 13 ⅜" V0 Production Packer (ref. [8])

2.4 Initial Reservoir Conditions

Hamilton is estimated to have a current reservoir pressure of approximately 10 bara.

The reservoir temperature is taken as 31.7 °C at a depth of 2450 ft (746.8 m) TVDSS.

2.5 Arrival Pressure

For this study, the arrival pressure offshore (at the top of the Hamilton riser) was taken as 35 barg.

2.6 Injectivity Requirements

2.6.1 Schedule, Flow Rates & Volumes

Injection is anticipated to commence in 2026 and continue for approximately 25 years.

The injection forecast for the reference case is 5 Mt/y (million tonnes per year) for the duration of store life. (ref. [8])

2.7 Ambient Temperature

Ambient sea bed temperatures at the Hamilton location are estimated to vary from 6 °C to 16 °C over a year. (ref. [8])

This study considers the minimum ambient sea-bed temperature of 6 °C as this is worst-case in terms of maintaining the CO_2 in the vapour phase.

A minimum ambient air temperature of -5 °C has been assumed for topsides pipework.

2.7.1.1 Geothermal Gradient

A linear geothermal gradient has been assumed from the ambient sea bed temperature of 6 °C, to the reservoir temperature of 31.7 °C at a depth of 2450 ft (746.8 m) TVDSS.

This is plotted in Figure 2.6 below, on which are also plotted the bottom hole temperatures of the gas-phase CO_2 injection wells which have been interpolated / extrapolated from this data.

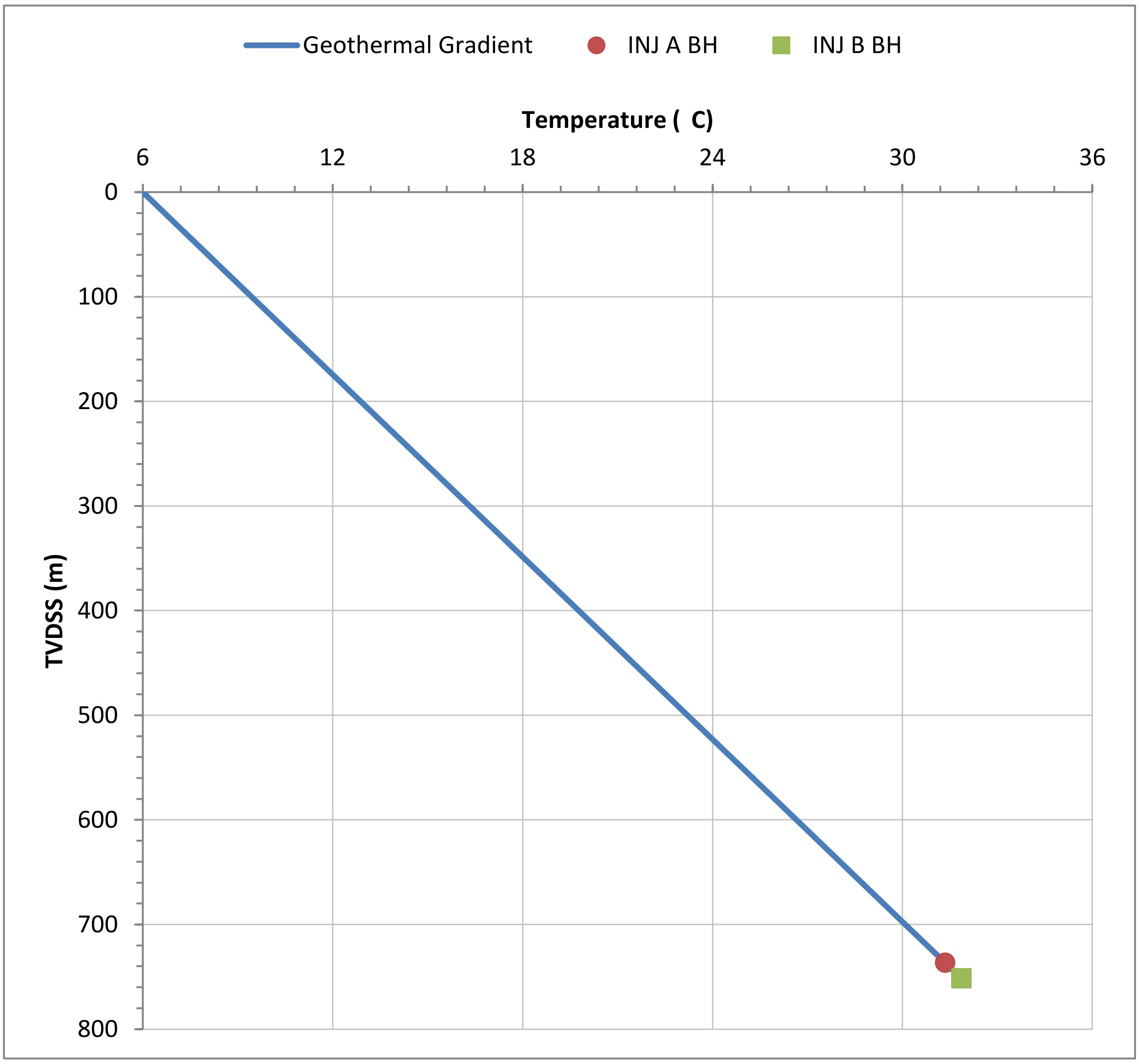

Figure 2.6 – Geothermal Gradient of Hamilton CO_2 Injection Wells

3 METHODOLOGY

Note on software used:

The simulation work for this study has been carried out using Aspen HYSYS V8.8.

Initially, PIPESIM was considered for carrying out these simulations, however, due to licencing limitations, PIPESIM proved unsuitable for accurately modelling flows of pure CO_2.

The approach was subsequently changed and HYSYS utilised in place of PIPESIM.

3.1 HYSYS Modelling

Modelling was carried out using Aspen HYSYS V8.8 using the Peng-Robinson property package.

The entire offshore infrastructure was modelled, from the inlet at Point of Ayr (POA), through the subsea transmission pipeline and riser, topsides pipework at Hamilton, topsides choke valves, and injection well tubing.

However, for the purposes of this technical note, the focus of attention was on the subsea CO_2 transmission pipeline and riser system.

Figure 3.1 shows the complete HYSYS model.

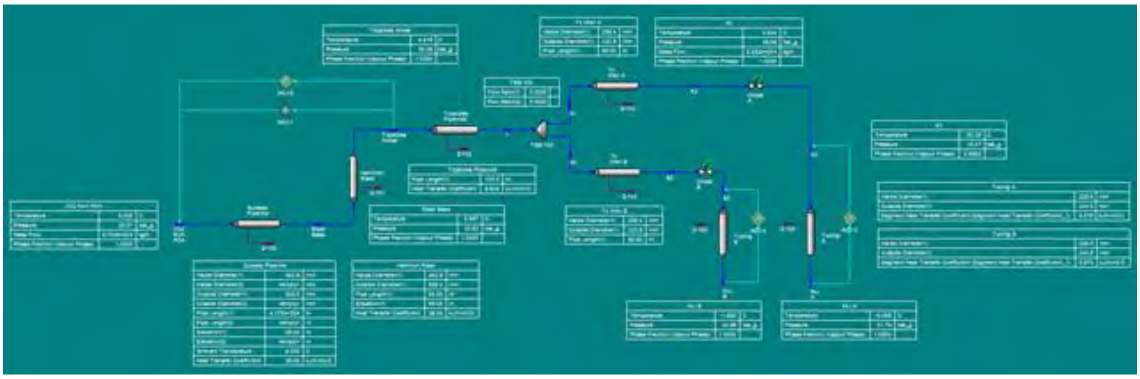

Figure 3.1 – HYSYS Model Screenshot

Figure 3.2 shows a close-up on the subsea pipeline and Hamilton riser.

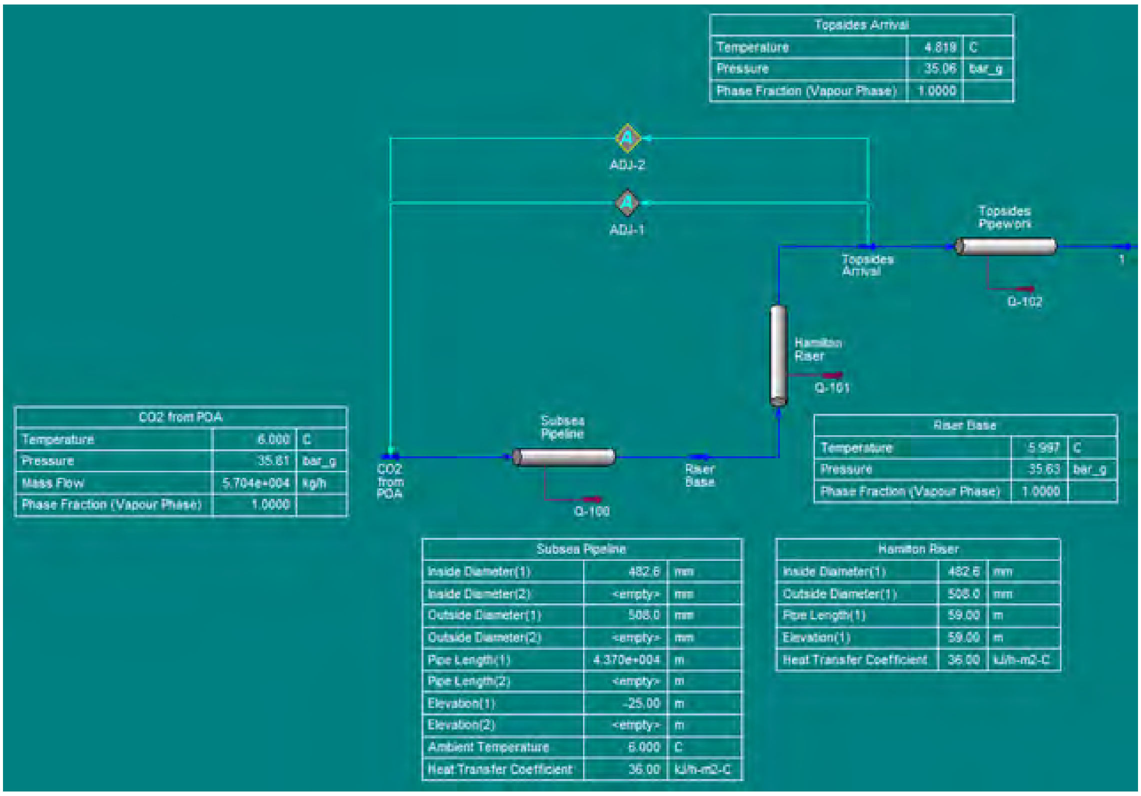

Figure 3.2 – HYSYS Model of Subsea Pipeline & Riser

The subsea pipeline and Hamilton riser are both modelled in HYSYS as pipe segments.

For single phase streams, the Darcy-Weisbach equation is used for pressure drop predictions. For two-phase streams, the HYSYS model is configured to use the Beggs and Brill (1979) flow correlation for horizontal, vertical, and inclined pipes.

Adjust block ADJ-1 was used to adjust the pipeline inlet pressure at POA in order to achieve an arrival pressure on Hamilton of 35 barg.

Adjust block ADJ-2 adjusts the pipeline inlet temperature at POA in order to achieve an arrival temperature on Hamilton of 30 °C for some of the sensitivity cases considered (see Section 0), however this adjust block was not used in the majority of cases.

3.2 Gas Phase Cases

The following gas phase cases were considered in this study:

Pipeline	Length (km)	Diameter (in NB)	Flow Rate (million tonnes / year)
Existing	43.7	20	0.50
			0.75
			1.00
			1.25
			1.50
			1.75
			2.00
New	26.0	16	0.50
			0.75
			1.00
			2.00
		22	2.50
		28	5.00

Table 3.1 – Gas Phase Cases Considered

The base case flow rate for this study was 5 Mt/y; however, at the considered conditions, this flow rate was not necessarily achievable through all the pipeline diameters considered. The range of flow rates in Table 3.1 were considered to estimate the approximate capacity of the existing 20 inch pipeline and new 16 inch (base case) pipeline.

3.3 Alternatives

In addition to the cases detailed in Table 3.1, the following additional cases were investigated:

1. Onshore Heating:
   Check of the required pipeline inlet conditions at POA in order to achieve an arrival temperature of 30 °C at Hamilton, for an arrival pressure of 35 barg, via a new 26 km, 16 inch NB, pipe-in-pipe (P-i-P) flowline, with an overall heat transfer coefficient (U value) of 1 W/m²K.

2. Provision of Warming Spool:
   Check of the length of warming spool required in order to return to a temperature of 6 °C following a flash of liquid CO_2 from 70 barg and 6 °C to 35 barg, which could allow the pipeline to run in the dense phase. Tubing would remain in two-phase flow operation.

3. Artificially Adjusting the Phase Envelope:
   Investigation of the impact of the presence of varying concentrations of nitrogen (N_2) or methane (CH_4) on the phase envelope.

4. Allowing Two-Phase Flow:
   Not considered as part of this scope. If two-phase flow were found to be operationally acceptable and controllable this could mitigate the need for heating. Two-phase flow brings with it additional challenges, in terms of modelling and in terms of operational difficulties (e.g. propensity for liquid holdup and slugging, modelling of impurities, etc.), and mechanical issues associated with pressure surges, vibrations and dynamic loading. If this option is to be explored, a more detailed study dedicated to two-phase flow operation would be required.

5. Alternative Heating Sources:
   Not considered as part of this scope. Possible alternatives include use of a heated pipeline and extracting heat from the sea. Heated pipelines have previously been considered in the Hamilton Storage Development Plan (ref. [8], Appendix 9) and have been discounted as they are considered not technically feasible.

COSTAIN

4 RESULTS

4.1 General

4.1.1 Bottom Hole Pressure Forecasts

Figure 4.1 shows the predicted bottom hole pressure (BHP) against cumulative CO_2 injected for gas-phase injection wells INJ 1 and INJ 2, each injecting at 2.5 Mtpa (ref. [8]).

It has been assumed that the relationship for lower injection rates would be similar due to the high levels of injectivity in the depleted gas reservoir.

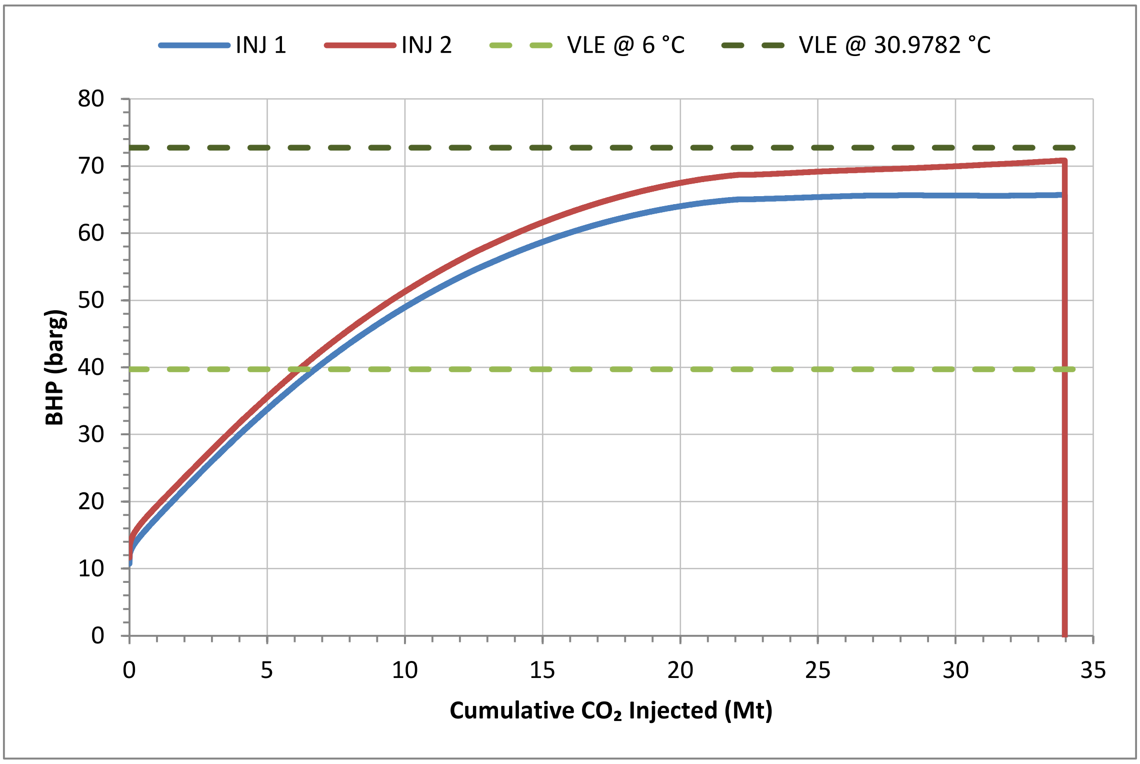

Figure 4.1 – BHP versus Cumulative CO_2 Injected for Gas-phase Operation (ref. [8])

The dashed green horizontal lines in the above chart represent the vapour-liquid equilibrium (VLE) pressures at the minimum ambient sea-bed temperature, 6 °C (light green) and the critical temperature of CO_2, ~31 °C (dark green), above which the CO_2 will condense into the liquid / dense phase.

From Figure 4.1 it can be seen that the BHP exceeds the saturation pressure at 6 °C at circa 6 – 7 million tonnes of CO_2 per well, or circa 12 – 14 million tonnes of total CO_2 injected.

At an injection rate of 5 million tonnes per year this point would be reached at the bottom of the tubing within 2 – 3 years. It would be reached topsides even sooner, as tubing head pressures exceed bottom hole pressures in injection wells.

4.1.2 Subsea Flowline Capacity Check

A plot of pressure drop in the subsea flowline versus mass flow rate of gaseous CO_2 is shown below in Figure 4.2 for a new 16 inch NB, 26 km pipeline and the existing 20 inch, 43.7 km gas export line (repurposed for CO_2 injection).

These results are for an arrival pressure on Hamilton of 35 barg.

The limiting factor in the following cases is avoidance of a phase change / two-phase flow in the subsea pipeline / riser. Higher flow rates result in higher pressure drop across the pipeline, which necessitate higher inlet pressures, resulting in the CO_2 at the inlet end of the pipeline being in the liquid phase. The boiling point of pure CO_2 at 6 °C (winter minimum ambient sea-bed temperature), hence the maximum pipeline inlet pressure is limited to approximately 39.7 barg.

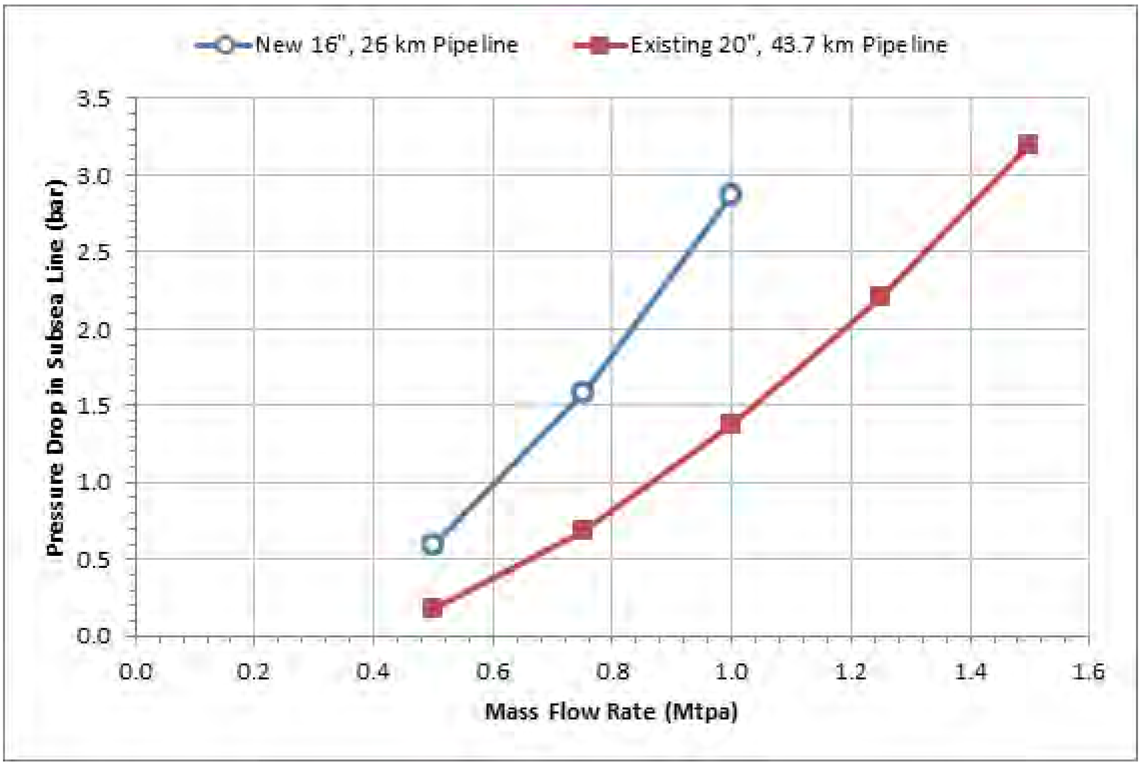

Figure 4.2 – Pressure Drop versus Mass Flow Rate – New 16" & Existing 20" Pipelines

For these conditions, the maximum flow rate of gaseous CO_2 through a new 16" pipeline is circa 1.0 Mtpa. For the existing 20" pipeline, the maximum flow rate is approximately 1.5 Mtpa.

4.1.3 Required Pipeline Diameters to Flow 2.5 Mtpa & 5 Mtpa Gaseous CO_2

In order to flow at a rate of 2.5 Mtpa gaseous CO_2, for a pipeline length of 26 km and an arrival pressure on Hamilton of 35 barg, would require a flowline of at least 22 inches NB.

In order to flow at 5 Mtpa, for the same conditions, would require a flowline of at least 28 inches NB.

However, given the pressure rise in the reservoir (Figure 4.1), at an injection rate of 5 Mtpa, injection would tail off after 2 – 3 years if operating in gas phase only without adjusting the operating philosophy by any other means.

4.1.4 Subsea Pipeline Pressure & Temperature Profiles

Figure 4.3 and Figure 4.4 below show respectively the pressure and temperature profiles through the various pipeline sizes and routings considered, at 5 Mtpa, or the maximum feasible flow rate through such a line where less than this.

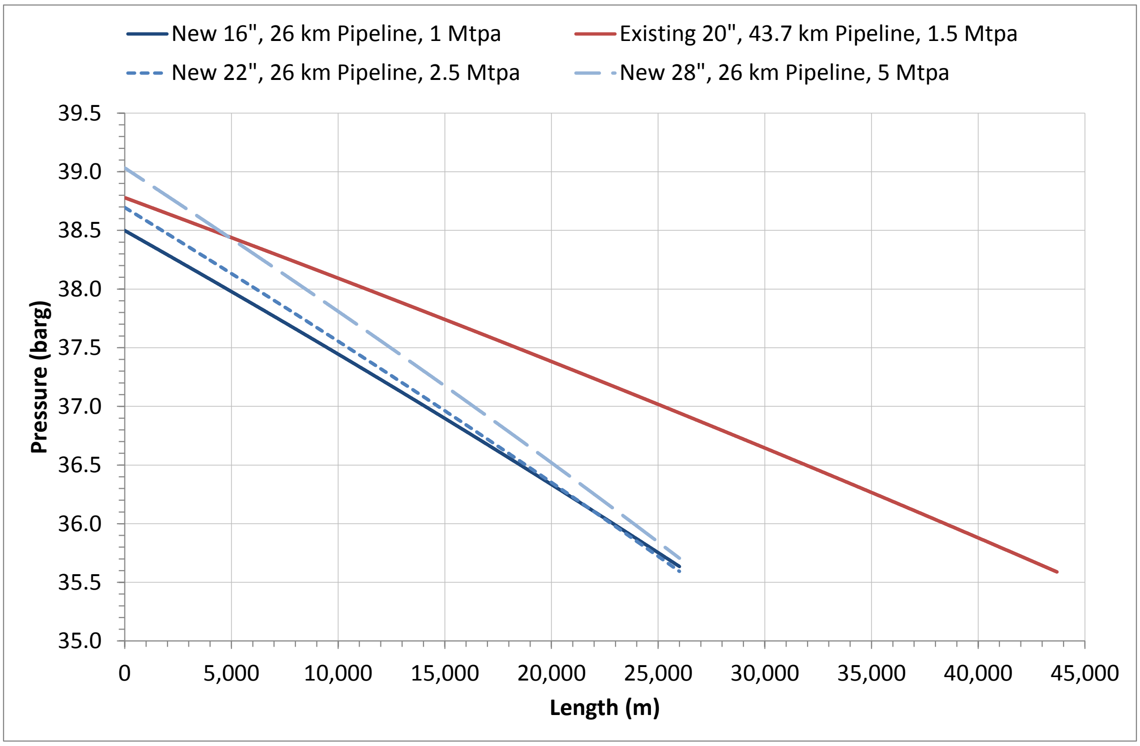

Figure 4.3 – Pressure Profiles through Subsea Pipeline Options (Uninsulated Pipelines, U = 10 W/m²K)

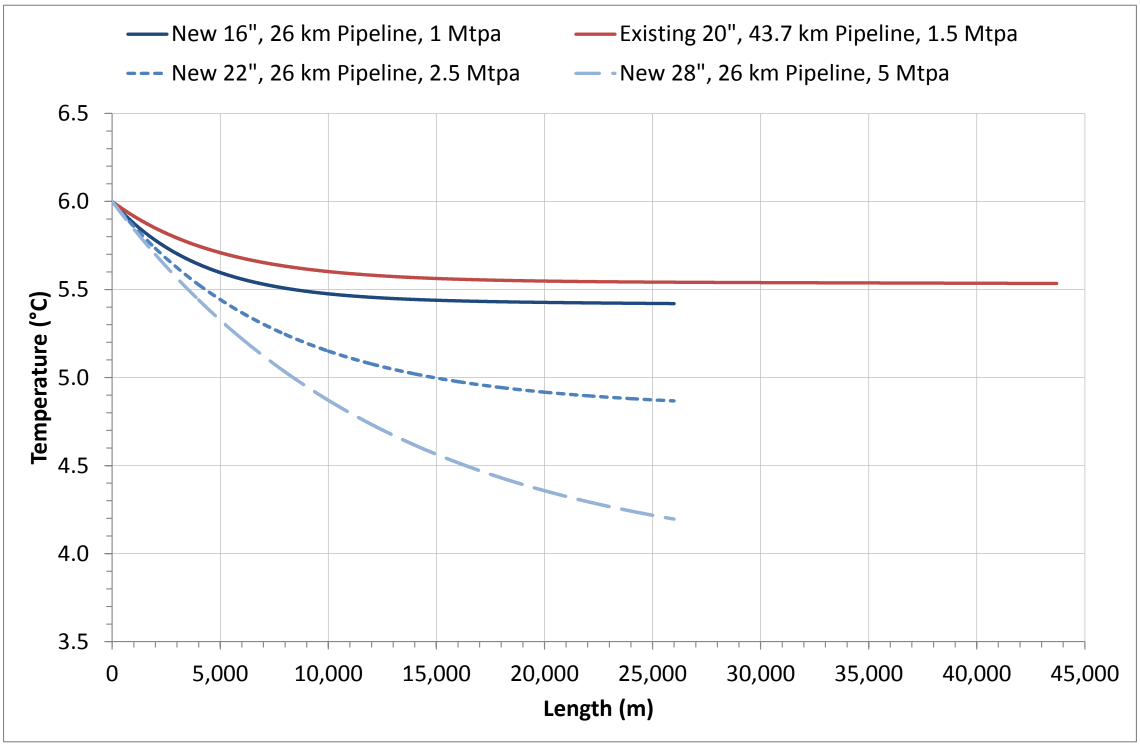

Figure 4.4 – Temperature Profiles through Subsea Pipeline Options (Uninsulated Pipelines, U = 10 W/m²K)

It can be seen in Figure 4.4 that, for these cases, the temperature of CO_2 in the pipelines drops below the ambient temperature of 6 °C. This is because the rate of heat transfer from the surrounding sea water to the CO_2 is very small compared to the rate of cooling from the Joule-Thomson effect due to the expansion of the gas in the pipeline.

4.2 Alternative Solutions

4.2.1 Onshore Heating with a P-i-P Solution

An alternative to providing offshore heating and the associated costs of providing a heat source offshore is to heat the CO_2 at source (POA) and thermally insulating the pipeline.

A common technique is to use a pipe-in-pipe (P-i-P) solution, which consists of an inner pipe, or “flowline”, through which the fluid flows, and an outer pipe, or “carrier”, which provides mechanical protection from the subsea environment. Encased between the flowline and the carrier is the thermal insulation of very low thermal conductivity, such as an aerogel. This enables very low overall heat transfer coefficients (U values) to be achieved.

In order to achieve an arrival temperature of 30 °C at Hamilton, for an arrival pressure of 35 barg, via a new 26 km, 16 inch NB, pipe-in-pipe flowline, with an overall heat transfer coefficient (U value) of 1 W/m²K, the following inlet conditions would be required at POA:

Pressure = 93.7 barg

Temperature = 87.2 °C

This is a high temperature at the POA terminal and would have large ramifications in the mechanical design of the pipeline. However, it would mean offshore heating would not be required during normal operations. During shut-ins however, the CO_2 temperature would cool to ambient conditions, making restarts problematic unless heating was available offshore.

It may be possible to operate the wells in 2 phase flow for a short duration, until the pipeline warms, but this would require thorough analysis and testing.

4.2.2 Warming Spool

A sensitivity case was run to attempt to determine the length of warming spool required in order to recover to a temperature of 6 °C following a flash of liquid CO_2 from 70 barg and 6 °C to 35 barg, which would allow the pipeline to run in liquid phase to the platform, thereby increasing the capacity of the pipeline.

Results of the HYSYS simulations of this scenario suggest that such a warming spool option is not feasible.

At the conditions specified, the CO_2 remains predominantly in the liquid phase and closely follows the saturation line as the pressure drops through the spool, vaporising very gradually.

Immediately following the flash, the temperature of the CO_2 stream is circa 1.6 °C. The temperature difference driving force from ambient (6 °C) to the CO_2 is very small; therefore the heat transferred per unit area will also be very small.

The heat transfer from the surroundings is negligible compared to the latent heat of the vaporising CO_2.

In order to raise the temperature of the CO_2 stream using ambient heat and a warming spool, the CO_2 must first all be allowed to vaporise. This would require an extremely long spool to achieve any warming of the CO_2 whatsoever. With a 16 inch NB pipeline, the associated pressure drops are too great to be achievable.

4.2.3 Artificial Modification of Phase Envelope

4.2.3.1 Using Nitrogen

A sensitivity case was run to investigate the impact of the presence of varying concentrations of nitrogen (N_2) on the phase envelope.

It is assumed that the N_2 would be injected at POA, or at the capture plant (or alternatively – depending on the capture technology – not removed in the first place).

The results of this sensitivity case are shown in Figure 4.5 and Table 4.1 below.

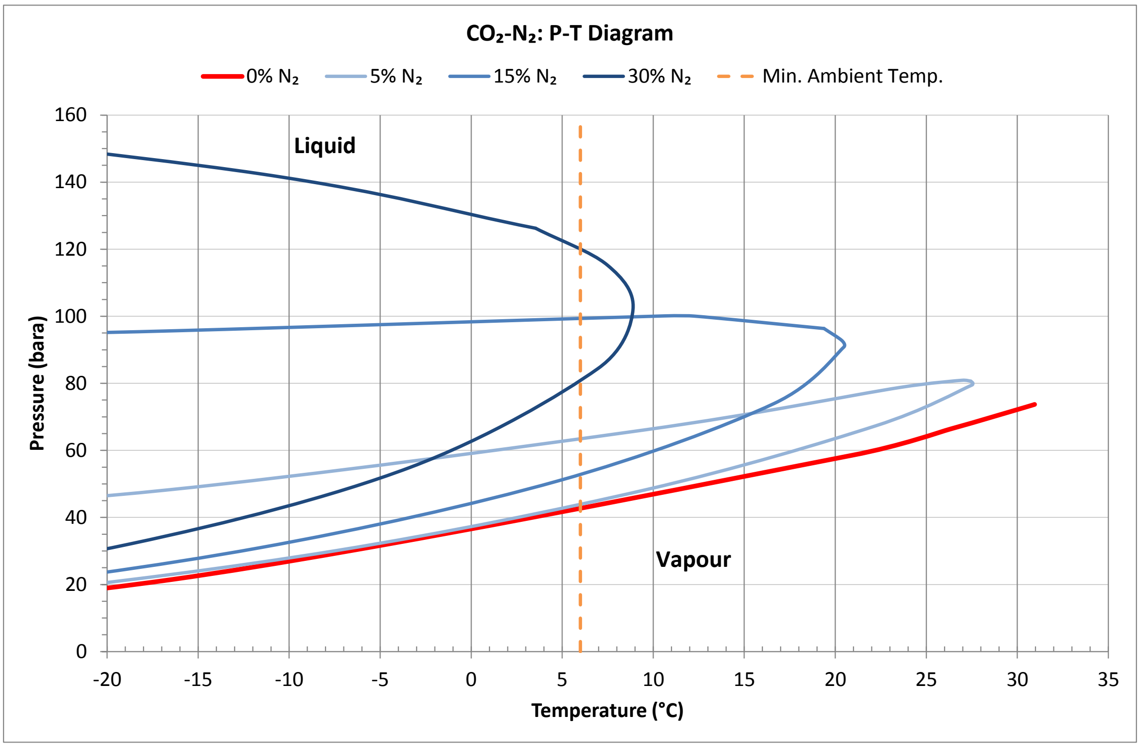

Figure 4.5 – P-T Diagram for CO_2-N_2 Mixtures at various concentrations of N_2

Composition (% N_2)	Critical Temperature (°C)	Critical Pressure (bara)
0	30.95	73.70
5	27.45	80.62
15	19.38	96.34
30	3.54	126.25

Table 4.1 – Critical Point for CO_2-N_2 Mixtures at various concentrations of N_2

The effect of the nitrogen on the phase envelope is marked. During early injection, N_2 concentrations would be kept low as it reduces the overall storage capacity of the reservoir. Over time this would rise to approximately 25 mole %, but would enable the CO_2 to be injected at 70 barg at 6 °C without liquid drop out, resulting in longer periods of gas-phase injection.

It is not clear what the ramifications might be of having a nitrogen generation plant at the capture plant. However, there may be issues with disposing nitrogen underground under the London 1996 Protocol (Ref [11]), the UN Convention on the Protection and Use of Transboundary Watercourses and International Lakes (Ref [12]), or other similar regulations or legislation, which would need to be addressed to make this a feasible option.

4.2.3.2 Using Methane

Another sensitivity case was run to investigate the impact of the presence of varying concentrations of methane (CH_4) on the phase envelope.

It is assumed that the existing Hamilton wells will be utilised to produce the gas which would then be metered, compressed and blended with the CO_2 prior to storage

The results of this sensitivity case are shown in Figure 4.6 and Table 4.2 below.

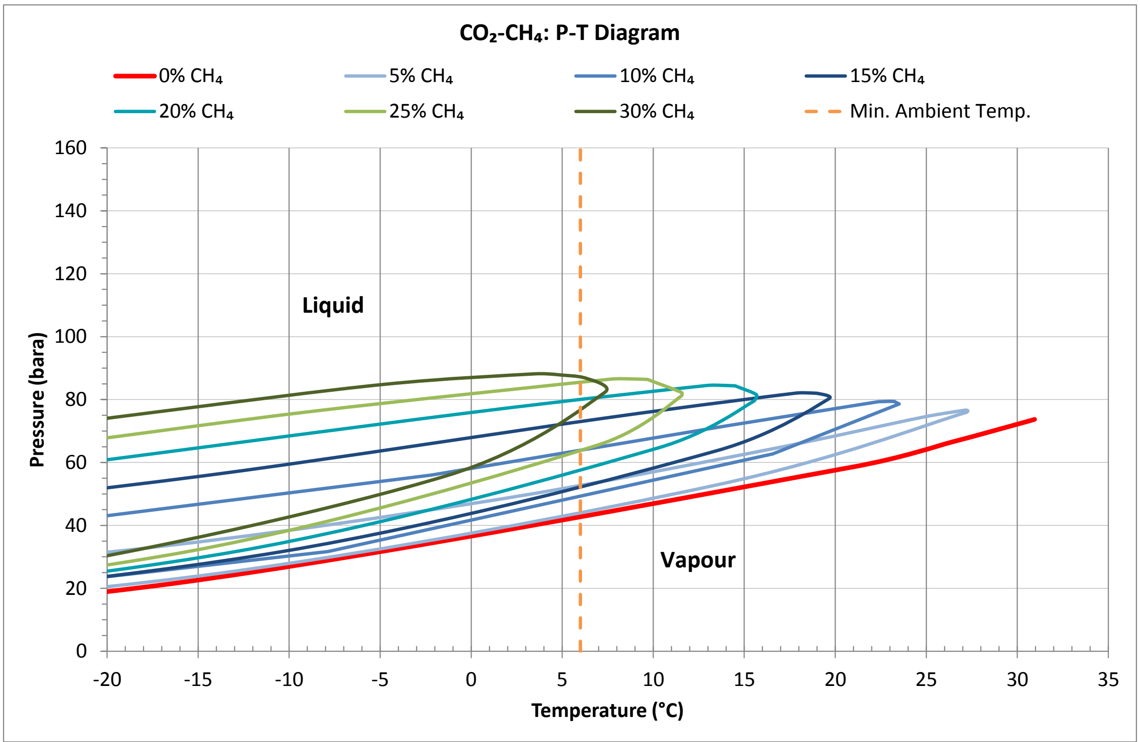

Figure 4.6 – P-T Diagram for CO_2-CH_4 Mixtures at various concentrations of CH_4

Composition (% CH_4)	Critical Temperature (°C)	Critical Pressure (bara)
0	30.95	73.70
5	27.22	76.60
10	23.24	79.38
15	19.02	81.98
20	14.51	84.36
25	9.68	86.40
30	4.53	88.04

Table 4.2 – Critical Point for CO_2-CH_4 Mixtures at various concentrations of CH_4

The effect of the methane on the phase envelope is similar to the use of nitrogen. During early injection, CH_4 concentrations would be kept low as it reduces the overall storage capacity of the reservoir. Over time this would rise to approximately 25% (by mole), but would enable the CO_2 to be injected at 70 barg at 6 °C without liquid drop out, resulting in longer periods of gas-phase injection.

Effect on Injection Profiles

Figure 4.7 and Figure 4.8 below show, respectively, the forecast injection rate and cumulative injection profile of pure CO_2 without any blending to adjust the phase envelope.

It should be noted that these profiles are predicated on the basis that the CO_2 will be heated in order to maintain it in the gas phase. Without any heating, gas phase injection of pure CO_2 can only be sustained for approximately the first 2 – 3 years, as previously noted in Sections 4.1.1 and 4.1.3.

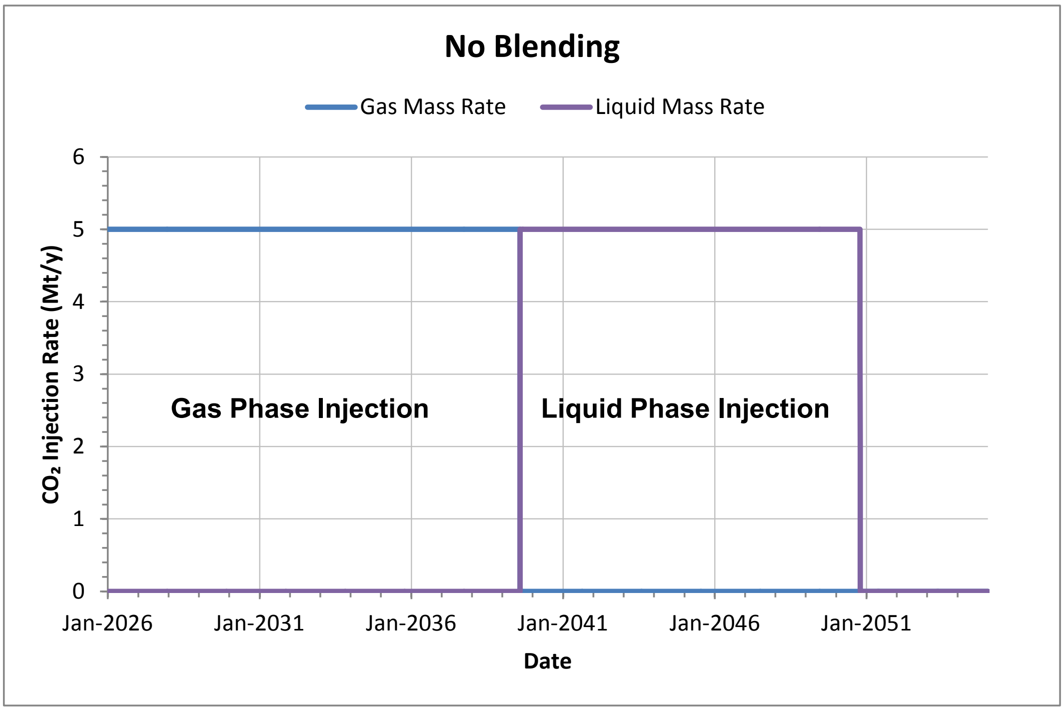

Figure 4.7 – CO_2 Injection Rate without Blending (with Heating)

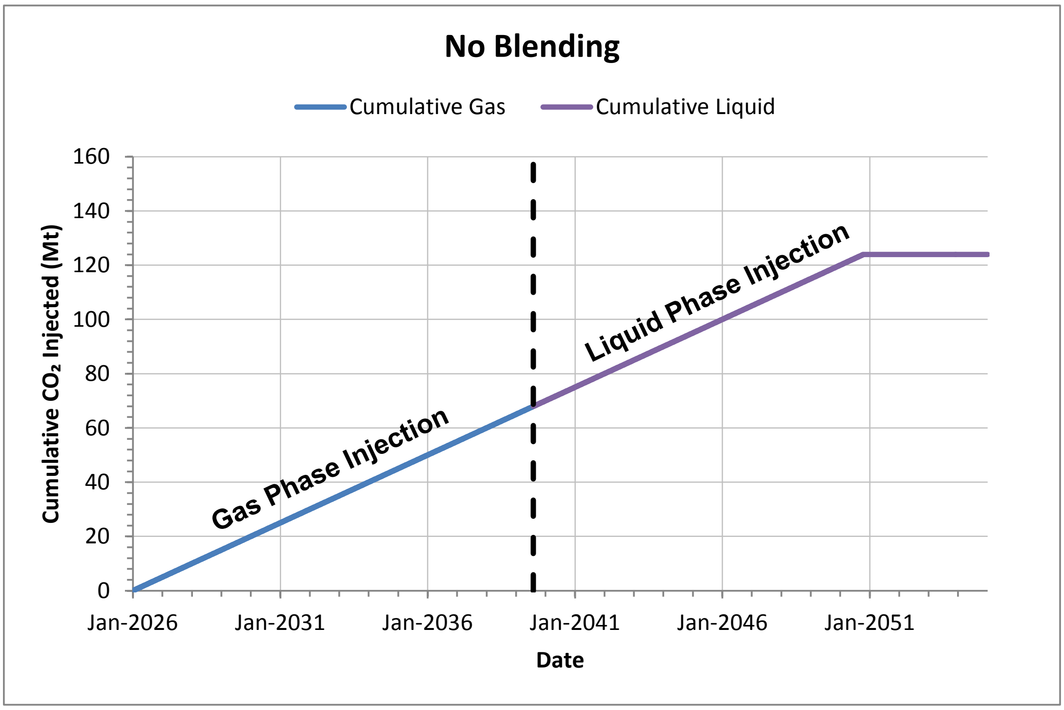

Figure 4.8 – CO_2 Cumulative Injection Profile without Blending (with Heating)

Figure 4.9 and Figure 4.10 show, for comparison, the injection rate and cumulative injection profile of pure CO_2 blended with CH_4 in order to adjust the phase envelope to allow operation at higher injection pressures whilst still in the gaseous phase (without heating). These assume sufficient supply of CH_4 and don't account for utilization of CH_4 for power and compression purposes.

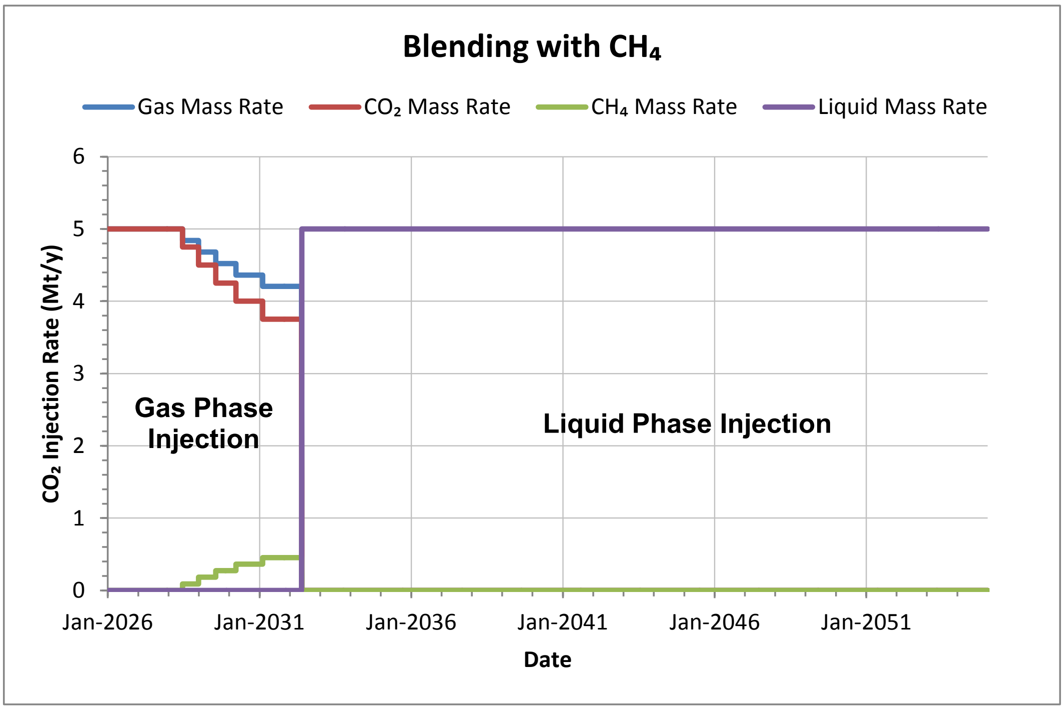

Figure 4.9 – Gas Injection Rates with Blending (without Heating)

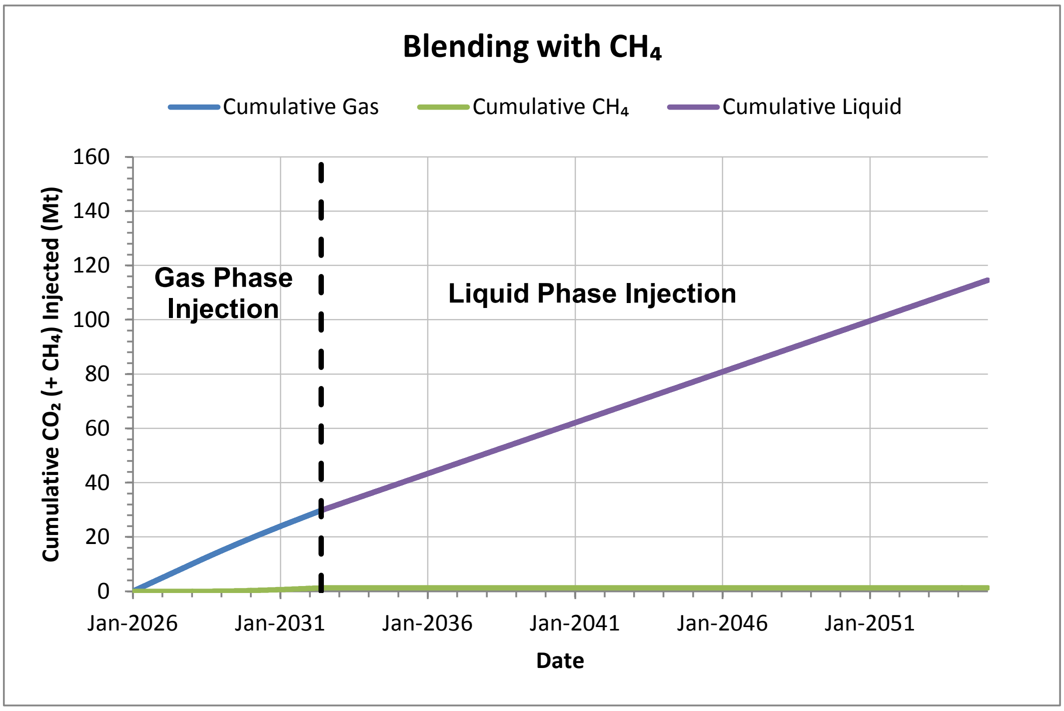

Figure 4.10 – Gas Cumulative Injection Profiles with Blending (without Heating)

As can be seen in Figure 4.9 and Figure 4.10, blending with CH_4 is expected to reduce the total capacity of the store by approximately 3.5 million tonnes. Production of the reservoir gas would increase some of the storage capacity, although reservoir modelling would be required to confirm the balance.

As discussed previously in Sections 4.1.1 and 4.1.3, gas phase operation without heating could not be sustained for a long period (circa 2 – 3 years if injecting pure CO_2). This period can be extended to circa 6 years by blending with CH_4. However, the switch-over to liquid phase injection will still be required much sooner than in the heated case (circa 13.5 years).

Figure 4.11 shows the rate of CH_4 required for blending for the above scenario.

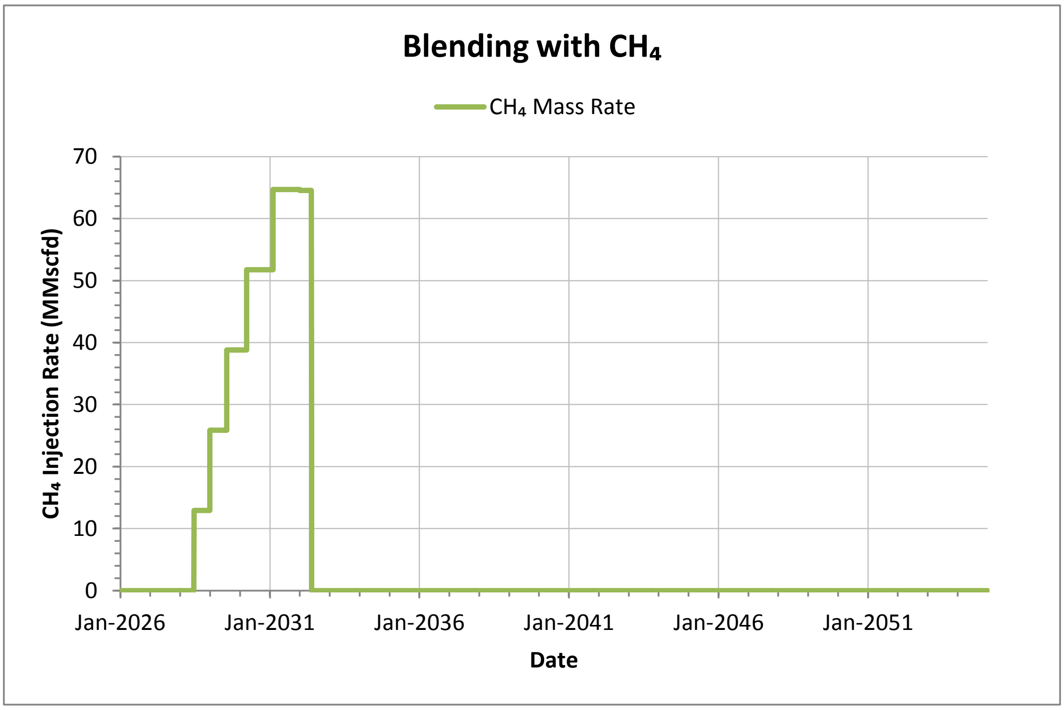

Figure 4.11 – CH_4 Injection Rate with Blending

The operating philosophy for this scenario is that the CH_4 injection rate is stepped up in increments of 5 mol% only when the phase envelope is required to be shifted further from the prevailing operating conditions.

As can be seen in Figure 4.11, it is anticipated that gas-phase operation can be sustained for approximately 2 ½ years without any CH_4 blending (i.e. injecting pure CO_2). Over the following 2 ½ years, the CH_4 injection rate is required to be stepped up in increments of circa 13 MMscfd, approximately every 6 months, until a total CH_4 injection rate of circa 65 MMscfd is reached (representing 25 mol% of the total injected gas).

It is noted that this is a substantial rate of gas.

For comparison, according to an Environmental Statement from 2014 (ref. [10]), total gas production for the entire Liverpool Bay operations (which includes the Hamilton, Hamilton North, Hamilton East, and Lennox gas fields) for the period 1st April – 31st December 2014 was 766,900,000 Sm^3 (27.083 Bscf). Taken as an average over this period, this is equivalent to an average production rate of circa 99 MMscfd.

It is considered extremely unlikely that such quantities of gas will be available for blending with the injected CO_2, as Hamilton approaches the end of its design life. Rather, it is likely that the injection rate of CO_2 will be required to be reduced in proportion to whatever is the available rate of natural gas for blending. This would extend the length of time that gas phase operations would continue, but would not increase the total capacity of the store.

5 CONCLUSIONS

5.1 General

- At an injection rate of 5 Mtpa, flow in the tubing will be two-phase within 2 – 3 years.
    - This can be postponed by reducing the injection rate. However, it is anticipated that this would not increase the overall gas capacity of the store, due to the high levels of injectivity in the depleted gas reservoir.
- For an arrival pressure of 35 barg on Hamilton, the maximum flow rate of gaseous CO_2 is approximately:
    - 1.0 Mtpa through a new 26 km, 16” pipeline.
    - 1.5 Mtpa through the existing 43.7 km, 20” pipeline.

  The limiting factor in these cases is avoidance of a phase change / two-phase flow in the subsea pipeline / riser. In order to achieve this, the maximum inlet pressure for the subsea flowline is limited to approximately 39.7 barg.
- In order to accommodate a rate of 2.5 Mtpa, the new flowline would be required to be a minimum of 22” NB.
- In order to accommodate a rate of 5 Mtpa, the new flowline would be required to be a minimum of 28” NB.

5.2 Alternative Solutions

- For a P-i-P option (U = 1 W/m²K), an inlet temperature of 87.2 °C would be required in order to achieve an arrival temperature of 30 °C at Hamilton. This is a high temperature and would have large ramifications on the mechanical design of the pipeline, but would eliminate the need for offshore heating during normal operation. However, restarts may be problematic unless heating is available offshore. (Heated pipelines have previously been considered in the Hamilton Storage Development Plan (ref. [8], Appendix 9) and ruled out as they are considered not technically feasible.)
- Utilising a warming spool to warm the CO_2 using ambient heat, following a flash from 70 barg to 35 barg is not considered to be feasible.
- Two-phase operation.
  Not considered as part of this scope. If two-phase flow were found to be operationally acceptable and controllable this could mitigate the need for heating. Two-phase flow brings with it additional challenges, in terms of modelling and in terms of operational difficulties (e.g. propensity for liquid holdup and slugging, modelling of impurities, etc.), and mechanical issues associated with pressure surges, vibrations and dynamic loading. If this option is to be explored, a more detailed study dedicated to two-phase flow operation would be required.
- The presence of nitrogen or methane significantly affects the phase envelope of the gas. It reduces the critical temperature and increases the critical pressure markedly, especially at concentrations of N_2 or CH_4 greater than 5 mol %.
  - It is not clear what the ramifications might be of having increased nitrogen at the capture plant, but there could be benefits in an increased nitrogen specification.
  - There may be issues with disposing nitrogen underground under the London 1996 Protocol (Ref [11]), the UN Convention on the Protection and Use of Transboundary Watercourses and International Lakes (Ref [12]), or other similar regulations or legislation, which would need to be addressed before this could be considered a feasible option.
  - Blending with CH_4 would allow the period of gas phase operation (without heating) to be extended from 2 – 3 years to circa 6 years.
  - However, blending with CH_4 would reduce the capacity of the store for storing CO_2 by an estimated 3.5 million tonnes.
  - A significant quantity of natural gas would be required for blending, up to circa 66 MMscfd for a CO_2 rate of 5 Mtpa. This is unlikely to be feasible.
  - A more feasible option is likely to be reducing the flow rate of CO_2 in proportion to the available rate of natural gas for blending.

6 REFERENCES

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[12] United Nations Economic Commission for Europe, Convention on the Protection and Use of Transboundary Watercourses and International Lakes, 17th March 1992, as Amended 28th November 2003, including decision VI/3 30th November 2012.

PROJECT	Strategic UK Storage Appraisal Project
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LEVEL 2 COST ESTIMATE

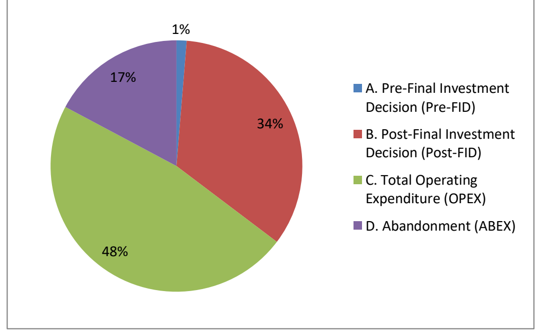
Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**16.4**	**6.5**	**22.9**		**29.7**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.9	0.4	1.3		1.7
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	4.5	4.1	8.6		11.1
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	4.0	0.4	4.4		5.7
A1.4	**Other**		7.0	1.6	8.6	30%	11.2
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	4.0	0.4	4.4		5.7
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	0.0	0.0	0.0		0.0
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**574.4**	**27.8**	**602.2**	**-**	**777.2**
B1.1	**Transportation**		131.6	4.3	135.9	-	176.7
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.5	0.2	1.7		2.2
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	57.0	3.9	61.0	30%	79.2
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	13.9	0.2	14.1		18.3
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	59.2	0.0	59.2		77.0
B1.2	**Facilities**		90.9	12.2	103.1	-	134.0
B1.2.1	Detailed Design		10.0	6.0	16.0		20.8
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	19.7	5.2	24.9	30%	32.3
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	16.4	1.0	17.4		22.6
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	44.8	0.0	44.8		58.3
B1.3	**Wells**		350.9	10.3	361.2	-	463.9
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	4.0	0.4	4.4		5.7
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	102.4	0.0	102.4		133.1
B1.3.3	Fabrication	-	0.0	0.0	0.0	30%	0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	244.5	9.9	254.4		325.0
		Wells 1-8	119.5	5.4	124.9		160.0
		Replacement Wells	125.0	4.5	129.5		165.1
B1.4	**Other**		1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**780.0**	**63.5**	**843.5**	**-**	**1085.0**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	57.6	3.0	60.7		78.9
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	271.4	24.7	296.1		384.9
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	174.2	8.1	182.3		225.4
C1.3.1	**Well Sidetracks and Workovers**	Local Sidetrack 1	39.5	1.8	41.3	30%	51.1
		Local Sidetrack 2	39.5	1.8	41.3		51.1
		Workover1	16.2	0.9	17.1		20.8
		Local Sidetrack 3	39.5	1.8	41.3		51.1
		Local Sidetrack 4	39.5	1.8	41.3		51.1
C1.4	**Other**		276.8	27.7	304.5	-	395.8
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	31.4	3.1	34.5		44.9
C1.4.2	Financial Securities		245.4	24.5	269.9	30%	350.9
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**205.2**	**23.0**	**228.3**	**-**	**393.3**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	17.8	1.8	19.6		25.5
D1.2	**Decommissioning - Facilities**	Que$tor	65.8	6.6	72.4	30%	94.1
D1.3	**Decommissioning - Wells**		63.5	10.8	74.3		193.2
D1.4	**Other**		58.1	3.9	61.9	-	80.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	38.7	3.9	42.6	30%	55.4
D1.4.2	Handover	additional 10 years of coverage	19.4	0.0	19.4		25.2

FIELD LIFE (YEARS)	34
CO2 STORED (MT)	510

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC

LEVEL 1 COST ESTIMATE SUMMARY



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY			
COST	**TOTAL COST (£ MM)**	**CATEGORY**	**COST (£ MM)**
CAPEX [A + B]	806.9	TRANSPORTATION	178.4
		FACILITIES	145.2
		WELLS	469.6
		OTHER	13.8
OPEX [C]	1085.0	TRANSPORTATION	78.9
		FACILITIES	384.9
		WELLS	225.4
		OTHER	395.8
ABEX [D]	393.3	TRANSPORTATION	25.5
		FACILITIES	94.1
		WELLS	193.2
		OTHER	80.5
TOTAL	2285.2	-	2285.2

LEVEL 1 COST ESTIMATE SUMMARY				
Category	**Primary Cost (£ MM)**	**Overheads (£ MM)**	**Total Cost excluding Contingency (£ MM)**	**Total Cost inc. Contingency (£ MM)**
A. Pre-Final Investment Decision (Pre-FID)	16.4	6.5	22.9	29.7
B. Post-Final Investment Decision (Post-FID)	574.4	27.8	602.2	777.2
C. Total Operating Expenditure (OPEX)	780.0	63.5	843.5	1085.0
D. Abandonment (ABEX)	205.2	23.0	228.3	393.3
TOTAL COST (CAPEX, OPEX, ABEX)			1696.9	**2285.2**
COST CO2 INJECTED (£ PER TONNE)			£3.33	**£4.48**

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LEVEL 2 COST ESTIMATE

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**16.4**	**4.4**	**20.8**		**27.1**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.9	0.4	1.3		1.7
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	4.5	2.0	6.5		8.5
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	4.0	0.4	4.4		5.7
A1.4	**Other**		7.0	1.6	8.6	30%	11.2
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	4.0	0.4	4.4		5.7
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	0.0	0.0	0.0		0.0
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**348.4**	**24.8**	**373.2**	**-**	**483.3**
B1.1	**Transportation**		123.8	4.3	128.1	-	166.6
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.5	0.2	1.7		2.2
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	57.0	3.9	60.9	30%	79.2
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	12.8	0.2	13.0		16.9
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	52.5	0.0	52.5		68.3
B1.2	**Facilities**		90.9	9.2	100.1	-	130.1
B1.2.1	Detailed Design		10.0	3.0	13.0		16.9
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	19.7	5.2	24.9	30%	32.3
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	16.4	1.0	17.4		22.6
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	44.8	0.0	44.8		58.3
B1.3	**Wells**		132.7	10.3	143.0	-	184.0
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	4.0	0.4	4.4		5.7
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	38.4	0.0	38.4		49.9
B1.3.3	Fabrication	-	0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	90.3	9.9	100.2	30%	128.4
		Well (Phase I)	90.3	5.4	95.7		122.5
		Replacement Wells	0.0	4.5	4.5		5.9
B1.4	**Other**		1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**658.5**	**59.5**	**718.0**	**-**	**923.2**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	54.3	2.9	57.2		74.4
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	259.2	23.6	282.8		367.6
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	95.2	8.1	103.3		124.2
C1.3.1	**Well Sidetracks and Workovers**	Local Sidetrack 1	39.5	1.8	41.3	30%	51.1
		Local Sidetrack 2	39.5	1.8	41.3		51.1
		Workover1	16.2	0.9	17.1		20.8
		Local Sidetrack 3	0.0	1.8	1.8		0.5
		Local Sidetrack 4	0.0	1.8	1.8		0.5
C1.4	**Other**		249.7	25.0	274.7	-	357.1
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	31.4	3.1	34.5		44.9
C1.4.2	Financial Securities		218.3	21.8	240.1	30%	312.2
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**162.7**	**22.9**	**185.6**	**-**	**284.0**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	16.8	1.7	18.5		24.1
D1.2	**Decommissioning - Facilities**	Que$tor	65.8	6.6	72.4	30%	94.1
D1.3	**Decommissioning - Wells**		22.0	10.8	32.8		85.3
D1.4	**Other**		58.1	3.9	61.9	-	80.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	38.7	3.9	42.6	30%	55.4
D1.4.2	Handover	additional 10 years of coverage	19.4	0.0	19.4		25.2

FIELD LIFE (YEARS)	34
CO2 STORED (MT)	510

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
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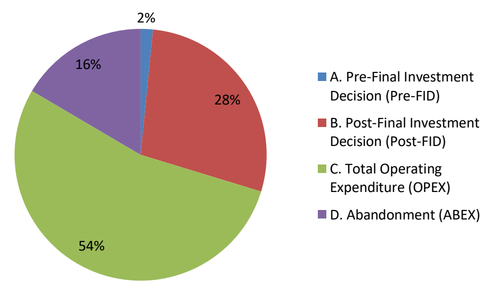
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC

LEVEL 1 COST ESTIMATE SUMMARY



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	510.4	TRANSPORTATION	168.3
		FACILITIES	138.6
		WELLS	189.8
		OTHER	13.8
OPEX [C]	923.2	TRANSPORTATION	74.4
		FACILITIES	367.6
		WELLS	124.2
		OTHER	357.1
ABEX [D]	284.0	TRANSPORTATION	24.1
		FACILITIES	94.1
		WELLS	85.3
		OTHER	80.5
TOTAL	1717.6	-	1717.6

LEVEL 1 COST ESTIMATE SUMMARY

Category	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)	16.4	4.4	20.8	27.1
B. Post-Final Investment Decision (Post-FID)	348.4	24.8	373.2	483.3
C. Total Operating Expenditure (OPEX)	658.5	59.5	718.0	923.2
D. Abandonment (ABEX)	162.7	22.9	185.6	284.0
TOTAL COST (CAPEX, OPEX, ABEX)			1297.6	**1717.6**
COST CO2 INJECTED (£ PER TONNE)			£2.54	**£3.37**

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Strategic UK CCS Storage Appraisal

– Minimum Viable Development (MVD) Summary

Document Number: CU-J1838-P-TN-002-A01

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Strategic UK CCS Storage Appraisal

Minimum Viable Development (MVD) Summary

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A01	25-Oct-2016	Issued for Comment	AW	AR	AR	

CONTENTS

ABBREVIATIONS

The following abbreviations are used throughout this document:

ABEX	Abandonment Expenditure
CAPEX	Capital Expenditure
CCS	Carbon Capture & Storage
CO_2	Carbon Dioxide
EISB	East Irish Sea Basin
ETI	Energy Technologies Institute
MVD	Minimum Viable Development
NUI	Normally Unmanned Installation
OPEX	Operating Expenditure
OSI	Offshore Storage Installation
POA	Point of Ayr
SNS	Southern North Sea
SUKSAP	Strategic UK Storage Appraisal Project
UKCS	United Kingdom Continental Shelf

1 INTRODUCTION

1.1 Background

Costain previously prepared level 2 cost estimates for the development plans proposed for each of the potential CO_2 storage sites considered as part of the SUKSAP project.

New cost estimates have been produced for each of the proposed developments, each for a Minimum Viable Development (MVD) option, considered to comprise the minimal facilities required to provide a feasible CCS solution for each of the sites.

1.2 Purpose of this Technical Note

The purpose of this technical note is to present the level 2 cost estimates for the Minimum Viable Development (MVD) options considered for each of the potential storage sites and to document the changes made from the original cost estimates.

2 MINIMUM VIABLE DEVELOPMENT (MVD) SUMMARY

2.1 Bunter Closure 36

2.1.1 Bunter Closure 36 Overview

Bunter closure 36 is located in the Southern North Sea (SNS), UKCS block 44/26, approximately 150 km due East of the town of Bridlington in Yorkshire. The original development plan consisted of the following:

CO_2 Stored:

- Injection Rate: 7 million tonnes per annum
- Design Life: 40 years
- Total CO_2 Stored: 280 million tonnes

Wells:

- 1 Appraisal / Monitoring Well (inc. abandonment)
- 10 (5 × 2) Injection Wells (inc. abandonment)
- 4 Side tracks
- 1 Well Workover

Facilities:

- Jacket: 4550 Te
- Topsides: 718 Te
- 12 Well Slots
  - 10 Used
  - 2 Spare

Pipelines:

- 160 km, 20” pipeline

Figure 2.1 shows the location of Bunter Closure 36 within the SNS and the proposed pipeline route from Barmston.

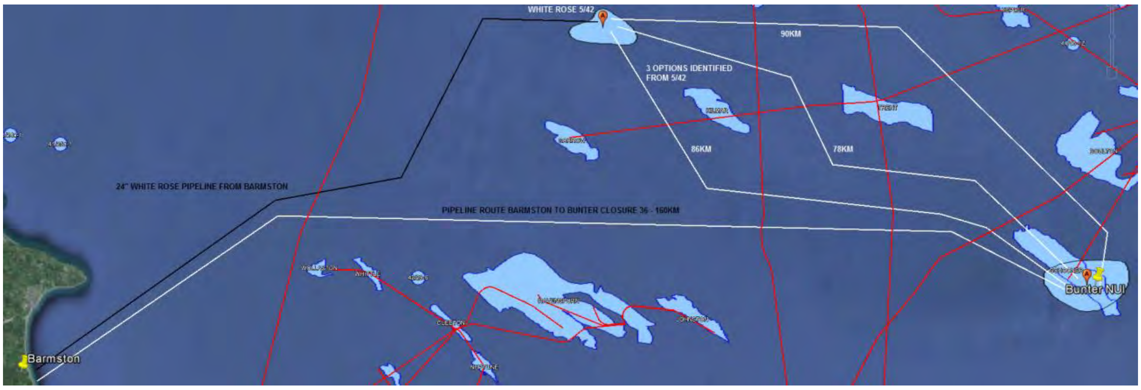


Figure 2.1 – Location of Bunter Closure 36 in the SNS, UKCS Block 44/26 and Proposed Pipeline Route from Barmston (ref. [5])

2.1.2 Bunter Closure 36 MVD and MVD+

For Bunter Closure 36, two new development plans were considered. These have been designated MVD (Minimum Viable Development) and MVD+. The MVD+ option is an intermediate proposal, between the MVD and the original development plans for economic comparisons.

The major differences between the original development plan and the MVD+ plan are:

- The reduced CO_2 injection rate (4 Mtpa compared to 7 Mtpa), which allows for fewer wells to be drilled, but reduces the total quantity of CO_2 stored over the operating life.
- A smaller pipeline is required to handle the reduced CO_2 rate (16 in compared to 20 in NB).
- A reduction in jacket size and weight (6 well slots rather than 12).
- The development still assumes 40 year operational life to maximise the investment of capital. The wells are re-drilled after 20 years in the same manner as the original development plan.

Moving from the MVD+ option down to the MVD option further reduces the CO_2 injection rate (from 4 to 2 Mtpa) and, as a result, the number of wells and pipeline diameter (to 12 in NB), but yields no further cost/weight savings on the jacket or the topsides facilities.

Table 2.1 shows a comparison of the MVD and MVD+ development options with that of the original development option for Bunter Closure 36, highlighting the differences between the options.

Scope	Original	MVD+	MVD
CO_2 Injection Rate (Mtpa)	7	4	2
Design Life (years)	40	40	40
Total CO_2 Stored (Mt)	280	160	80
Wells:			
No. of Wells*:	10 (5 × 2)	5	2
Active	8 (4 × 2)	4	2
Spare	2 (1 × 2)	1	0
No. of Well Slots:	12	6	6
Used	10	5	2
Spare	2	1	4
Pipeline:			
Diameter (in NB)	20	16	12
Length (km)	160	160	160
Facilities:			
Total Jacket Weight (Te)	4,550	3,950	3,950
Total Topsides Weight (Te)	718	715	715

Table 2.1 – Bunter Closure 36 – Comparison of MVD and MVD+ with Original Scope

2.1.3 Cost Comparison: MVD Versus Original

A comparison of the total costs of the development options is shown in Figure 2.2 below. Figure 2.3 shows the cost per tonne comparison. Detailed cost tables are included in Appendix A.

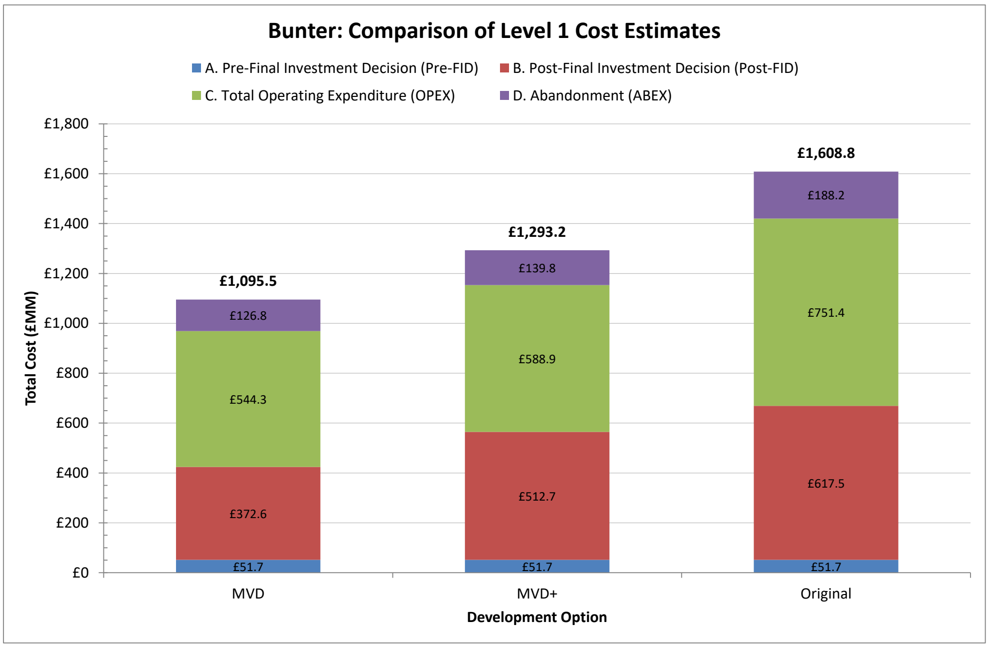


Figure 2.2 – Total Cost Comparison: MVD & MVD+ versus Original Development Plan: Bunter C36

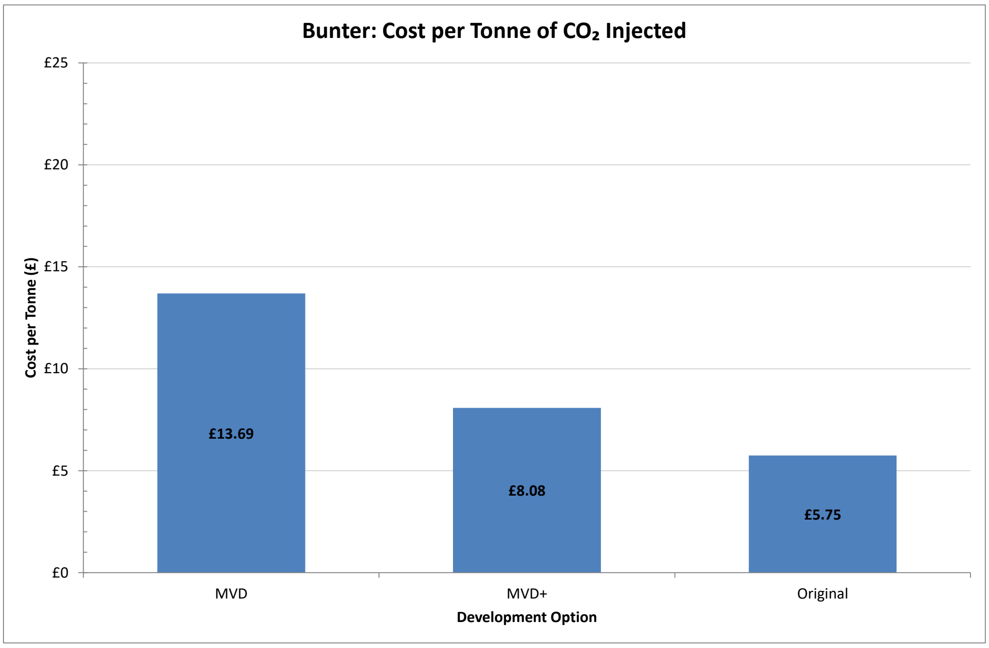


Figure 2.3 – Cost per Tonne of CO_2 Comparison: MVD & MVD+ versus Original Development Plan: Bunter C36

2.1.4 Pros & Cons of MVD Approach: Bunter C36

Advantages	Disadvantages
Average sensitivity between MVD and capacity: MVD+ 20% less total lifecycle costs = 43% less injection capacity. MVD 32% less total lifecycle costs = 71% less injection capacity.	
16% less CAPEX and 20% less total life cycle costs (MVD+)	43% less injection/storage capacity (MVD+).
37% less CAPEX and 32% less total life cycle costs (MVD).	71% less injection/storage capacity (MVD).
Wells can be added incrementally if trunkline is large enough.	Small 12” pipeline restricts injection rate resulting in only a 29% of storage being utilised.
	Second new pipeline required to boost injection rates at high incremental cost. Pipelines long and require landfall crossings.
	Jacket cost relatively insensitive to capacity reduction and reduced available slots would restrict expansion.

Table 2.2 – Pros & Cons of MVD Approach: Bunter C36

2.2 Captain X

2.2.1 Captain X Overview

Captain is located in the Moray Firth Basin, UKCS block 13/30, approximately 75 km Northeast of St Fergus. The original development plan consisted of the following:

CO_2 Stored:

- Injection Rate: 3 million tonnes per annum
- Design Life: 20 years
- Total CO_2 Stored: 60 million tonnes

Wells:

- 2 Injection Wells (inc. Abandonment)
- 1 Monitoring Well / Spare Injector (inc. Abandonment)
- 2 Sidetracks
- No Workovers

Facilities:

- Jacket: 6233 Te
- Topsides: 570 Te
- 4 Well Slots
  - 3 Used
  - 1 Spare

Pipelines:

- Re-use of the existing 16” Atlantic and Cromarty Pipeline
- New 8 km, 16” pipeline

Figure 2.4 shows the location of Captain within the Moray Firth Basin and the proposed pipeline route from St Fergus.

Figure 2.4 – Location of Captain in the Moray Firth basin, UKCS Block 13/30 and Proposed Pipeline Route from St Fergus (ref. [5])

2.2.2 Captain X MVD

The original development plan was restricted to 60 Mt due to the storage limits in the aquifer. The MVD plan assumes the same limitation, however the injection rate is reduced and the period increased accordingly so that the same storage capacity can be achieved. A subsea solution has been proposed, which removes the need for the platform and its associated infrastructure and OPEX. There are some limitations associated with removal of the surface facilities, such as ability to filter the CO_2 for fines, to vent the system, and to monitor the wells in the same manner.

A schematic of the minimum viable development for Captain X is shown in Figure 2.5 below.

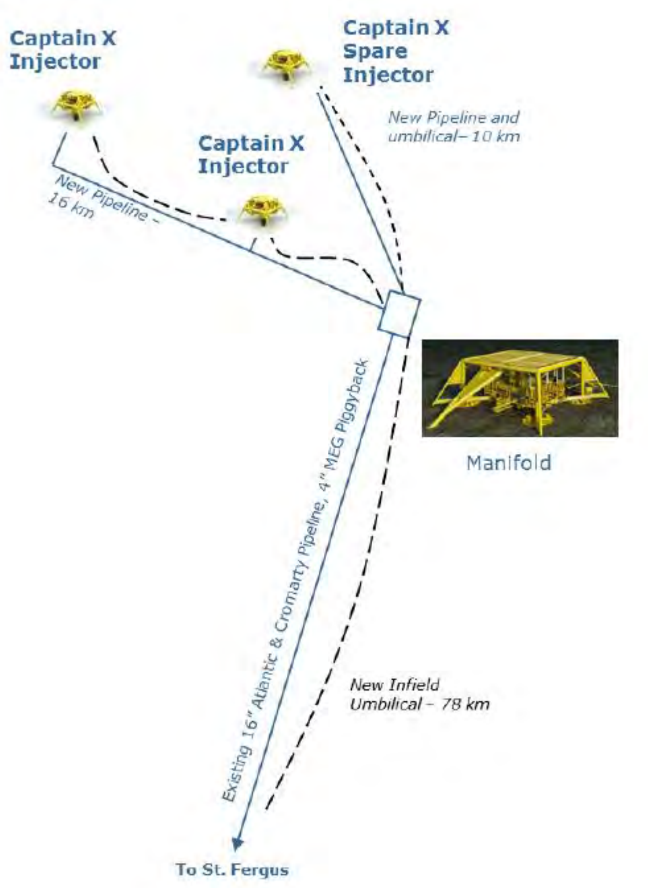


Figure 2.5 – Captain X Minimum Viable Development Schematic

The major differences between the original development plan and the MVD plan are:

- The reduced CO_2 injection rate (2 Mtpa compared to 3 Mtpa) but requires a longer design life to accommodate the same total quantity of CO_2 stored over operating life (30 vs 20 years).
- A smaller new pipeline section is required to handle the reduced CO_2 rate (12 in compared to 16 in NB). The existing Atlantic and Cromarty pipeline would be adopted.
- The original option included a NUI at Captain, the MVD option is for a subsea development only with subsea wells.
- Inclusion of an umbilical from shore to provide power and controls to the subsea facilities.
- Adoption of the Atlantic and Cromarty 4" MEG line to provide MEG for start-up and restart operations.

Table 2.3 shows a comparison of the MVD development option with that of the original development option for Captain, highlighting the differences between the options.

Scope	Original	MVD
CO_2 Injection Rate (Mtpa)	3	2
Design Life (years)	20	30
Total CO_2 Stored (Mt)	60	60
Wells:		
No. of Wells:	3	3
Active	2	2
Spare	1	1
No. of Well Slots:		
Used	3	No Topsides (Subsea Development Only)
Spare	1	
Pipeline*:		
Diameter (in NB)	16	12
Length (km)	8	26 (16 + 10)
MEG System	Provided in infield umbilical from NUI	Existing 4" A&C Pipeline
Facilities:		
Total Jacket Weight (Te)	6233	No Topsides (Subsea Development Only)
Total Topsides Weight (Te)	570	

Table 2.3 – Captain – Comparison of MVD and Original Scopes

** Pipeline scope also includes for the acquisition of the existing Atlantic & Cromarty pipeline.*

2.2.3 Cost Comparison: MVD Versus Original

A comparison of the total costs of the development options is shown in Figure 2.6 below. Figure 2.7 shows the cost per tonne comparison. Detailed cost tables are included in Appendix A.

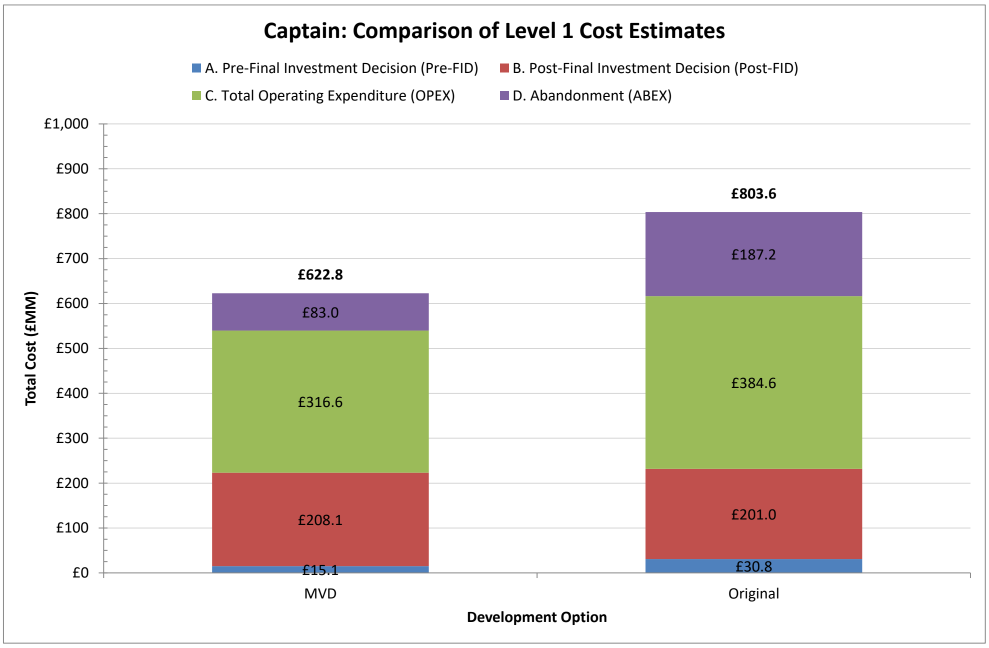


Figure 2.6 – Total Cost Comparison: MVD versus Original Development Plan: Captain X

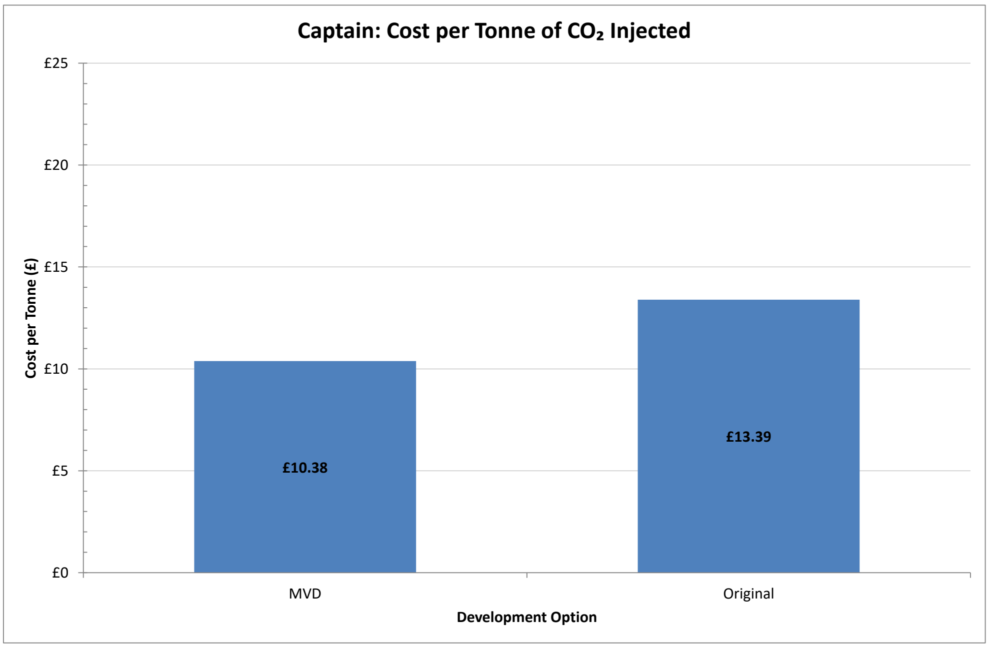


Figure 2.7 – Cost per Tonne of CO_2 Comparison: MVD versus Original Development Plan: Captain X

2.2.4 Pros & Cons of MVD Approach: Captain X

Advantages	Disadvantages
Good sensitivity between MVD and storage volume: MVD 22% less total life cycle costs = 33% less injection capacity.	
4% less CAPEX and 22% less total life cycle costs.	33% less injection capacity. (33% longer design life required for same capacity).
Reuse of existing Atlantic Cromarty pipeline reduces cost sensitivity and enables future expansion.	Smaller infield pipeline restricts capacity.
Full utilisation of storage capacity still possible over longer duration.	Several design risk issues still exist with a subsea development.
Subsea development potentially possible.	

Table 2.4 – Pros & Cons of MVD Approach: Captain X

2.3 Forties 5 Site 1

2.3.1 Forties 5 Site 1 Overview

Forties is located in the Central North Sea and Moray Firth Basins, with the proposed location of the NUI in UKCS block 22/14, approximately 215 km East of St Fergus. There was a 2 site development plan proposed for Forties due to the nature of the storage aquifer.

South Site

CO_2 Stored:

- Design Life: 40 years
- Total CO_2 Stored: 170 million tonnes

Wells:

- 1 Appraisal Well
- 8 (4 × 2) Injection Wells (inc. abandonment)
- 1 Monitoring Well / Spare Injector
- 5 Sidetracks
- No Workovers

Facilities:

- Jacket: 4800 Te
- Topsides: 553 Te
- 6 Well Slots
    - 5 Used
    - 1 Spare

Pipelines:

- 216 km, 24” pipeline

North Site (Developed as a subsea tieback to Southern Platform after 10 years)

CO_2 Stored:

- Design Life: 30 years
- Total CO_2 Stored: 130 million tonnes

Wells:

- 4 Injection Wells (inc. abandonment)
- 3 Sidetracks
- 3 Workovers

Facilities:

- Subsea Template Only, No Topsides Facilities

Pipelines:

- 24 km, 12” infield pipeline

Figure 2.8 shows the proposed location of the Forties NUI and Forties North subsea template in the Central North Sea / Moray Firth Basin and the proposed pipeline route from St Fergus.

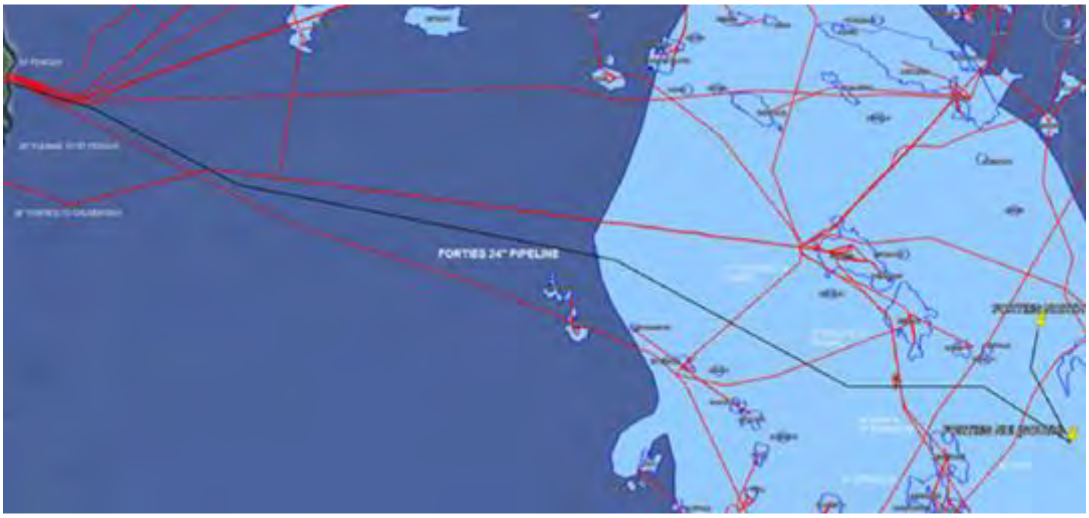


Figure 2.8 – Location of Forties in UKCS Blocks 22/14 (Forties NUI) and 22/8 (Forties North) and Proposed Pipeline Route from St Fergus (ref. [5])

2.3.2 Forties 5 Site 1 MVD

The major differences between the original development plan and the MVD plan are:

- Original development plan includes both a NUI at Forties South and a subsea template at Forties North; MVD includes only Forties South.
- The reduced CO_2 injection rate, which allows for a smaller pipeline (20 in compared to 24 in NB), but reduces the total quantity of CO_2 stored over the operating life.
- The facilities at the southern site are essentially the same for both the original development and the MVD.

Table 2.5 shows a comparison of the MVD development option with that of the original development option for Forties, highlighting the differences between the options.

Scope	Original	MVD
CO_2 Injection Rate (Mtpa)	6 – 8	6
Design Life (years)	40	40
Total CO_2 Stored (Mt)	300	170
Southern Site:	NUI	NUI
Active Wells	4	4
Spare Wells	1	1
Northern Site:	Subsea Template	N/A
Active Wells	4	N/A
Spare Wells	1	N/A
Main Pipeline:		
Diameter (in NB)	24	20
Length (km)	216	216
Infield Pipeline:		
Diameter (in NB)	12	N/A
Length (km)	25	N/A

Table 2.5 – Forties – Comparison of MVD and Original Scopes

2.3.3 Cost Comparison: MVD Versus Original

A comparison of the total costs of the development options is shown in Figure 2.9 below. Figure 2.10 shows the cost per tonne comparison. Detailed cost tables are included in Appendix A.

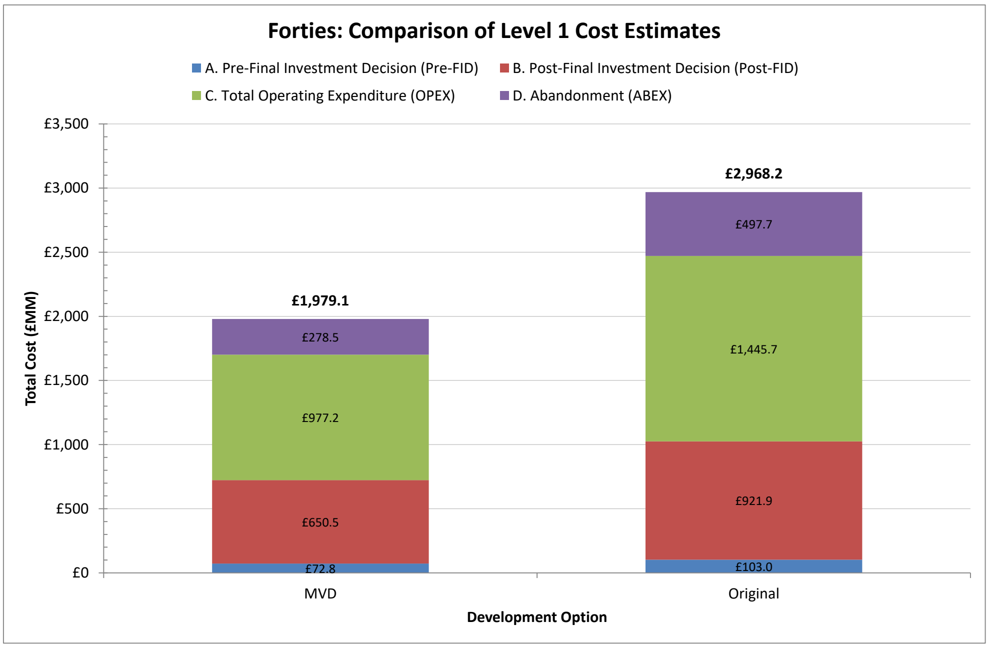


Figure 2.9 – Total Cost Comparison: MVD versus Original Development Plan: Forties 5 Site 1

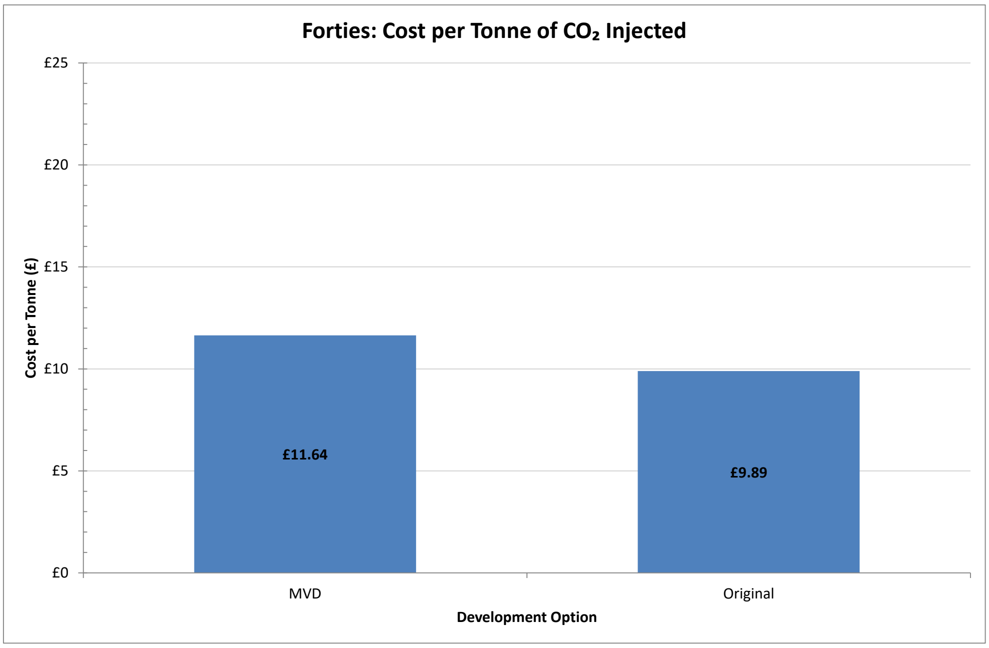


Figure 2.10 – Cost per Tonne of CO_2 Comparison: MVD versus Original Development Plan: Forties 5 Site 1

2.3.4 Pros & Cons of MVD Approach: Forties 5 Site 1

Advantages	Disadvantages
Good sensitivity between MVD and capacity: MVD 33% less total life cycle costs = 25% less injection capacity.	
29% less CAPEX and 33% less total life cycle costs.	25% less injection capacity and 43% less storage capacity.
Northern injection site pipeline and wells offer a clear incremental reduction in scope and CAPEX.	Very high initial CAPEX (£3 billion) makes even an MVD development a very high cost at around £2 billion.
	Very long new trunkline (>200 km) results in small cost reduction for reduced diameter.
	Long distance from shore makes field unattractive for MVD.
	Poor utilisation of reservoir storage capacity given high cost of the trunkline.

Table 2.6 – Pros & Cons of MVD Approach: Forties 5 Site 1

2.4 Hamilton

2.4.1 Hamilton Overview

The Hamilton field is located in the East Irish Sea Basin (EISB), in UKCS block 110/13a, approximately 23 km from the Lancashire coast, due West of the town of Formby in Merseyside. Figure 2.11 shows the location of the Hamilton field and the Liverpool Bay pipeline system.

Figure 2.11 – Location of Hamilton in the EISB, UKCS Block 110/13a (ref. [1])

The original development plan consisted of the following:

CO_2 Stored:

- Injection Rate: 5 million tonnes per annum
- Design Life: 25 years
- Total CO_2 Stored: 125 million tonnes

Wells:

- 2 Gas Phase Injection Wells (inc. Abandonment)
- 2 Dense Phase Injection Wells (inc. Abandonment)
- 1 Spare Well (inc. Abandonment)
- 4 Sidetracks
- 2 Gas Phase Well Workovers

Facilities:

- Jacket: 705 Te
- Topsides: 542 Te
- 5 Well Slots

Pipelines:

- 26 km, 16” pipeline

2.4.2 Hamilton MVD

One of the major cost drivers for the Hamilton field was the inclusion of heating that was required to achieve the full injected capacity of the store. A separate study investigated the alternatives to heating (Ref 6). A viable solution is to operate purely in gas phase conditions which avoid the need for heating however it limits the injection capacity to 12-14 tonnes. In order to improve the economics for this low storage volume, the injection rate is reduced in the MVD development plan from 5 to 1.5 Mtpa for a period of 8 years. With the shortened duration there is an opportunity to extend the use of the Hamilton platform which would reduce the need for a new platform. The use of gas phase and the shortened duration also mean that the existing pipeline is a lower cost alternative to installing a new pipeline. This would however require the Douglas facilities to be decommissioned which could delay the program.

It has been assumed that there is a cost of £20MM in modifications required for the Hamilton platform and that the OPEX would be the same as for the original development plan with the heating component removed. The ABEX for the Hamilton platform has been included in the cost estimate however it is assumed that the gas wells are decommissioned by others.

The major differences between the original development plan and the MVD plan are:

- gas-phase operation only (no dense phase wells, and no spare wells)
- the reduced CO_2 injection rate (1.5 Mtpa compared to 5 Mtpa), which allows for gas phase operation for a longer duration, but reduces the total quantity of CO_2 stored over the operating life
- re-use the existing 20” gas export pipeline via Douglas rather than laying a new 26 km pipeline from Point of Ayr to Hamilton (will require a new subsea spool piece to connect the two existing pipeline at Douglas)
- re-use the existing Hamilton NUI (with modifications) rather than a new NUI
- No OPEX related heating or power cable from shore.

Table 2.7 shows a comparison of the MVD and original development options for Hamilton, highlighting the differences between the options.

Scope	Original	MVD
CO_2 Injection Rate (Mtpa)	5	1.5
Design Life (years)	25	8
Total CO_2 Stored (Mt)	125	12
Wells:		
No. of Wells*:	5	2
Active: Gas Phase	2	2
Active: Dense Phase	2	0
Spare	1	0
No. of Well Slots:	5	N/A (Re-use existing NUI)
Used	5	
Spare	0	
Pipeline:		
Diameter (in NB)	16	20 (existing*)
Length (km)	26	0.3*
Facilities:		
Total Jacket Weight (Te)	705	N/A
Total Topsides Weight (Te)	542	N/A
Heating / Power	Yes, 26km power cable from shore	None, small local generation on NUI
Platform CAPEX	~£100 MM	£20 MM in mods
Facilities OPEX	~£12 MM pa	No Heating ~ £7 MM pa

Table 2.7 – Hamilton – Comparison of MVD and Original Scopes

** **Note:** Hamilton MVD re-uses the existing 20" pipeline via Douglas. This will require a new subsea spool piece to connect the existing POA-Douglas and Douglas-Hamilton pipelines. 300 m of 16 in pipeline has been assumed to allow for this in the initial cost estimate.*

2.4.3 Cost Comparison: MVD Versus Original

A comparison of the total costs of the development options is shown in Figure 2.12 below. Figure 2.13 shows the cost per tonne comparison. Detailed cost tables are included in Appendix A.

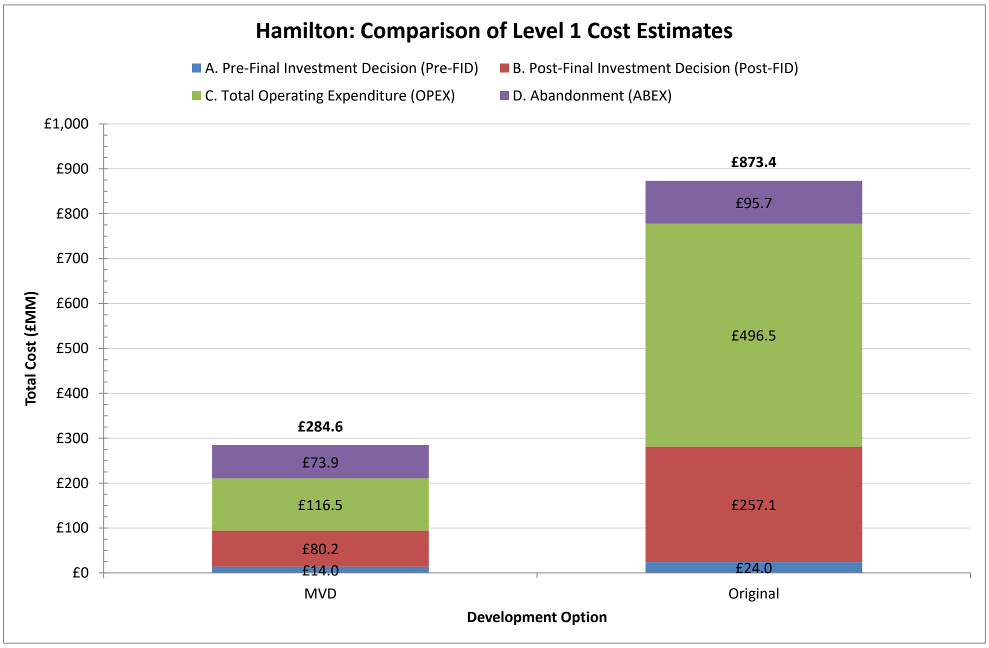


Figure 2.12 – Total Cost Comparison: MVD versus Original Development Plan: Hamilton

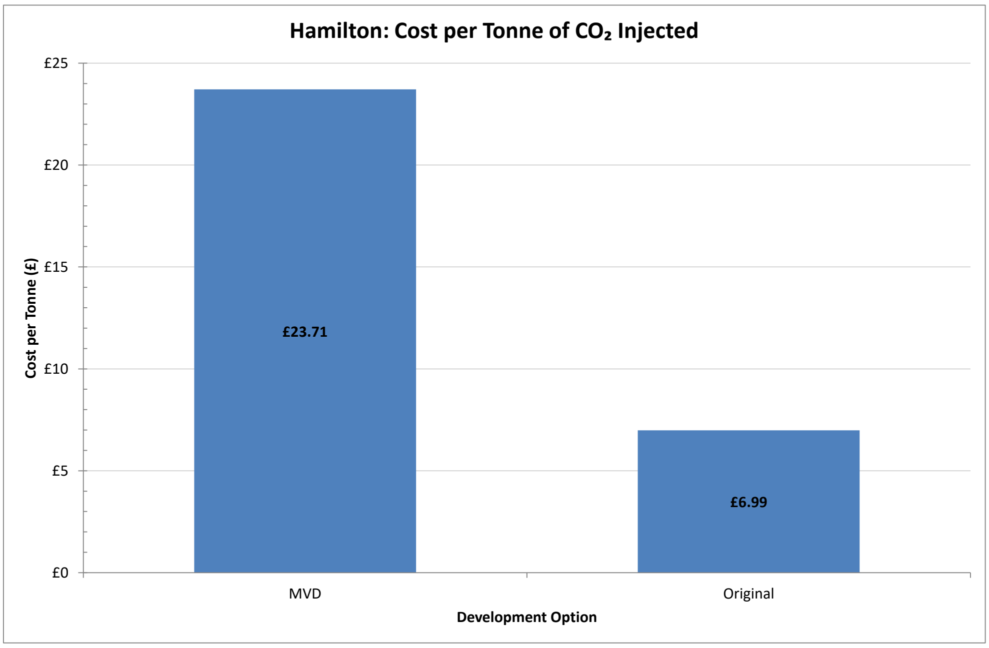


Figure 2.13 – Cost per Tonne of CO_2 Comparison: MVD versus Original Development Plan: Hamilton

2.4.4 Pros & Cons of MVD Approach: Hamilton

Advantages	Disadvantages
Good sensitivity between MVD and capacity: MVD 67% less total life cycle costs = 70% less injection capacity.	
66% less CAPEX and 67% less total life cycle costs.	70% less injection capacity.
Low OPEX – no heating required.	Gas only injection restricts storage capacity to only 10% of total storage capacity obtainable with liquid phase injection with heating.
Reuse of existing platform, pipelines and wells.	Storage capacity expansion costs (CAPEX and OPEX would be high).
Possible to phase expansion to liquid injection by adding heating later if required.	Reliant upon decommissioning of Douglas Platform and handover of Hamilton facilities.
Potential test site for 2-phase injection as reservoir pressure increases.	
Gaseous phase injection has relatively few design issues compared to liquid (low temperature, materials, cracking).	

Table 2.8 – Pros & Cons of MVD Approach: Hamilton

2.5 Viking A

2.5.1 Viking A Overview

Viking is located in the Southern North Sea (SNS), UKCS block 49/12, approximately 160 km due East of the town of Grimsby. The original development plan consisted of the following:

CO_2 Stored:

- Injection Rate: 5 million tonnes per annum
- Design Life: 26 years
- Total CO_2 Stored: 130 million tonnes

Wells:

- 2 Injection Wells (inc. abandonment)
- 1 Monitoring Well /Spare Injector (inc. abandonment)
- 2 Side tracks
- 1 Well Workover

Facilities:

- Jacket: 1316 Te
- Topsides: 540 Te
- 3 Well Slots

Pipelines:

- 185 km, 20” pipeline

Figure 2.14 shows the location of Viking within the SNS and the proposed pipeline route from Barmston.

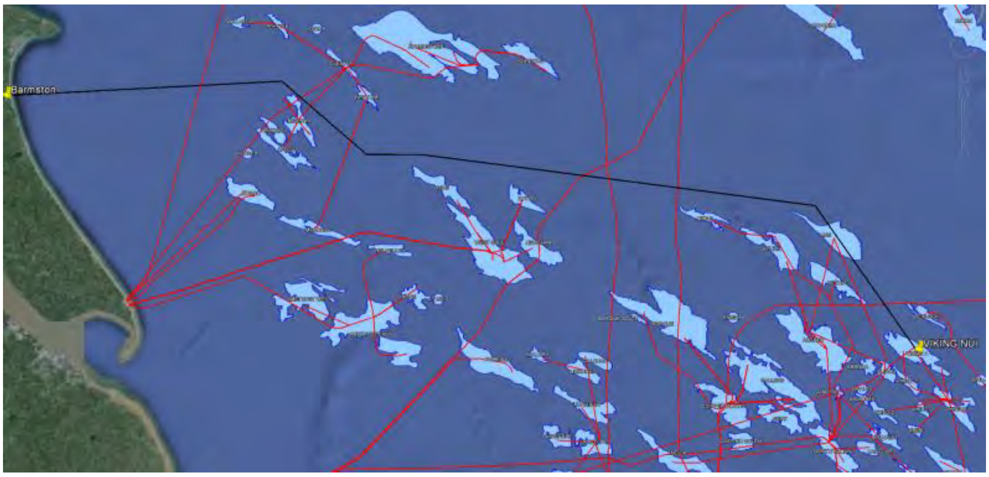


Figure 2.14 – Location of Viking in UKCS Block 49/12 and Proposed Pipeline Route from Barmston (ref. [5])

2.5.2 Viking A MVD

As the Viking field is a depleted gas reservoir with low residual reservoir pressure, it experiences the same heating requirements as Hamilton. A slightly different approach to Hamilton MVD has been proposed for the MVD. It has been assumed the flow rates have been reduced and the heating requirement has been mitigated by other measures e.g. by allowing 2 phase conditions in the well.

The major differences between the original development plan and the MVD plan are:

- Reduced CO_2 injection rate (2.5 Mtpa compared to 5 Mtpa)
- Smaller pipeline to handle the reduced CO_2 rate (16 in compared to 20 in NB),
- No spare well in the MVD option
- No heating and therefore no power cable and power costs

Table 2.9 shows a comparison of the MVD and original development options for Viking, highlighting the differences between the options.

Scope	Original	MVD
CO_2 Injection Rate (Mtpa)	5	2.5
Design Life (years)	26	26
Total CO_2 Stored (Mt)	130	65
Wells:		
No. of Wells*:	3	2
Active	2	2
Spare	1	0
No. of Well Slots:	3	3
Used	3	2
Spare	0	1
Pipeline:		
Diameter (in NB)	20	16
Length (km)	185	185
Facilities:		
Total Jacket Weight (Te)	1316	1316
Total Topsides Weight (Te)	540	534
Heating / Power	Yes, 90km power cable from shore	None, small local generation on NUI

Table 2.9 – Viking – Comparison of MVD and Original Scopes

2.5.3 Cost Comparison: MVD Versus Original

A comparison of the total costs of the development options is shown in Figure 2.15 below. Figure 2.16 shows the cost per tonne comparison. Detailed cost tables are included in Appendix A.

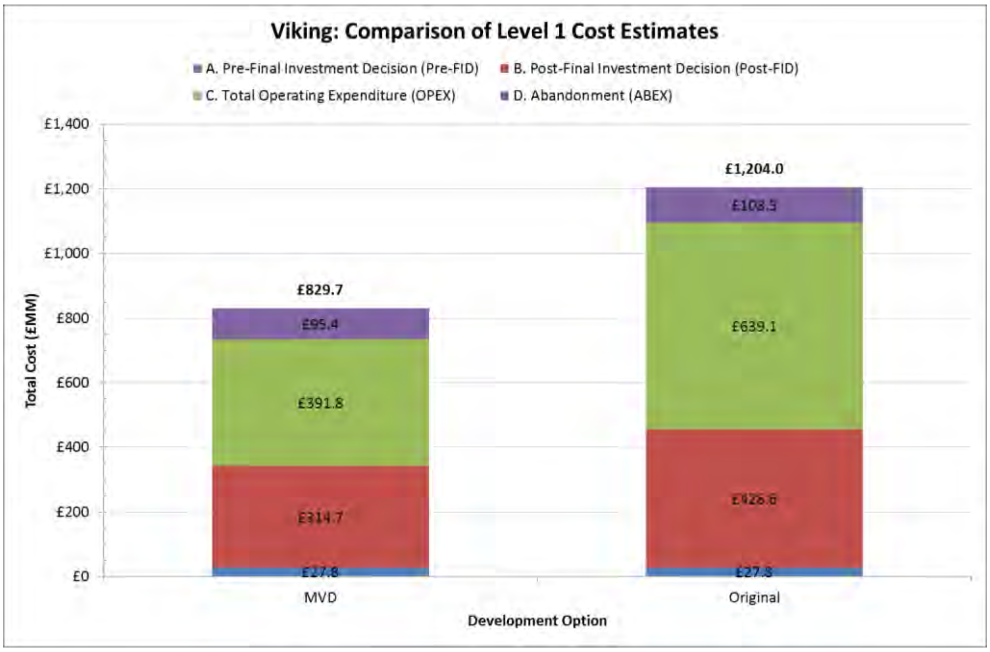


Figure 2.15 – Total Cost Comparison: MVD versus Original Development Plan: Viking A

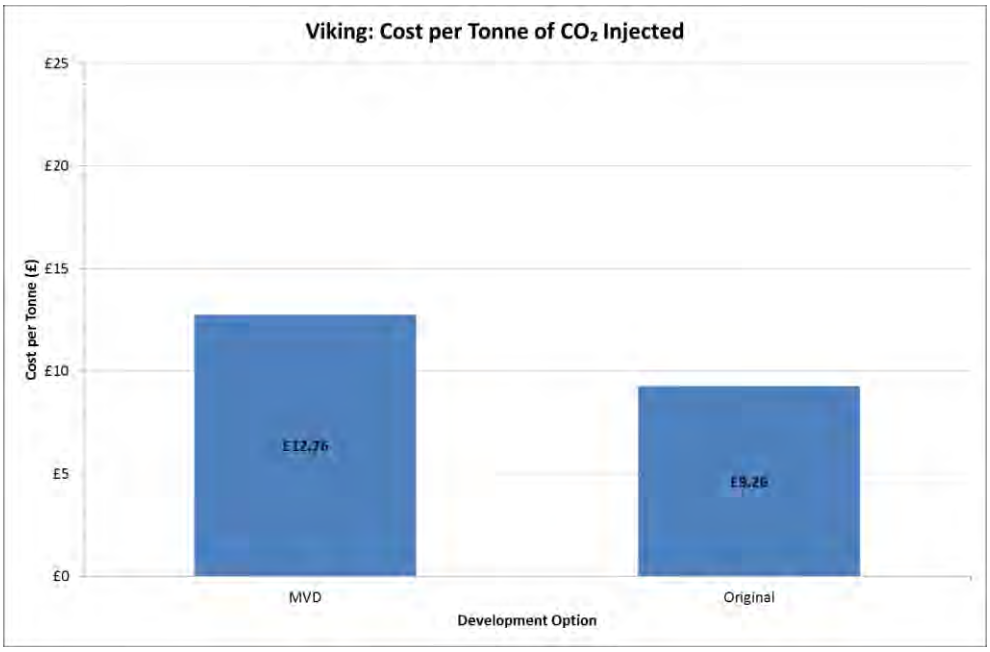


Figure 2.16 – Cost per Tonne of CO_2 Comparison: MVD versus Original Development Plan: Viking A

2.5.4 Pros & Cons of MVD Approach: Viking A

<table>
<tr><th>Advantages</th><th>Disadvantages</th></tr>
<tr><td colspan="2">Average sensitivity between MVD and capacity:
MVD 31% less total lifecycle costs = 50% less injection capacity.</td></tr>
<tr><td>25% less CAPEX and 31% less total life cycle costs.</td><td>50% less injection/storage capacity.</td></tr>
<tr><td></td><td>Very long new trunkline results in small cost reduction for reduced diameter.</td></tr>
<tr><td></td><td>Jacket / topsides cost relatively unchanged with reduced flowrate. Offshore heating still required.</td></tr>
<tr><td></td><td>Long distance from shore makes field unattractive for MVD.</td></tr>
</table>

Table 2.10 – Pros & Cons of MVD Approach: Viking A

3 REFERENCES

[1] https://www.ukoilandgasdata.com

[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/525261/Pipelines_May_2016.xls

[3] https://itportal.decc.gov.uk/web_files/ems/2013/BHP_EMS.pdf

[4] http://www.offshore-technology.com/projects/bhp/images/bhp4.jpg

[5] R10 10198ETIS ETI Completion Mtg 161020 FINAL.pptx

[6] CU-J1838-P-TN-001-A01 - Hamilton - Gas Phase Operation without Heating Technical Note

APPENDIX A – COST ESTIMATE SUMMARIES

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 5: VIKING Minimum Viable Development
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

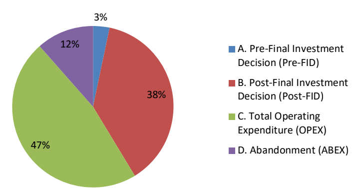
LEVEL 2 COST ESTIMATE

	Category	Comment	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**15.6**	**5.8**	**21.4**		**27.8**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.6	0.2	0.8		1.0
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	8.8	4.0	12.8		16.7
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	2.0	0.2	2.2		2.9
A1.4	**Other**		4.3	1.3	5.6	30%	7.2
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	1.3	0.1	1.4		1.8
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	0.0	0.0	0.0		0.0
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**226.7**	**15.8**	**242.5**	**-**	**314.7**
B1.1	**Transportation**		141.7	4.8	146.4	-	190.4
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	0.4	0.1	0.5		0.7
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	49.6	3.5	53.1	30%	69.0
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	22.0	1.2	23.2		30.1
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	69.7	0.0	69.7		90.6
B1.2	**Facilities**		46.9	5.3	52.2	-	67.9
B1.2.1	Detailed Design	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	10.0	3.0	13.0		16.9
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	8.6	2.0	10.5	30%	13.7
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	5.9	0.4	6.3		8.1
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	22.4	0.0	22.4		29.1
B1.3	**Wells**		37.2	4.7	41.9	-	53.9
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	2.0	0.2	2.2		2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	9.2	0.9	10.1		13.9
B1.3.3	Fabrication	-	0.0	0.0	0.0	30%	0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	26.0	3.6	29.6		37.1
		Platform Injector 1-2 + MW	26.0	3.6	29.6		37.1
B1.4	**Other**		1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**279.0**	**24.3**	**303.3**	**-**	**391.8**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	47.3	2.5	49.8		64.7
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	120.9	11.0	131.9	30%	171.5
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	38.3	3.6	41.9		52.0
C1.3.1	Well Sidetracks and Workovers	Workover + Local Sidetracks	38.3	3.6	41.9		52.0
C1.4	**Other**		72.5	7.3	79.8	-	103.7
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	6.8	0.7	7.5		9.7
C1.4.2	Financial Securities		65.7	6.6	72.27	30%	94.0
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**66.3**	**7.1**	**73.4**	**-**	**95.4**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	19.1	1.9	21.1		27.4
D1.2	**Decommissioning - Facilities**	Que$tor	26.7	2.7	29.4	30%	38.2
D1.3	**Decommissioning - Wells**		10.3	1.9	12.1		15.7
D1.4	**Other**		10.1	0.7	10.8	-	14.1
D1.4.1	Post Closure Monitoring	includes data management and interpretation	6.8	0.7	7.4	30%	9.7
D1.4.2	Handover	additional 10 years of coverage	3.4	0.0	3.4		4.4

FIELD LIFE (YEARS)	26
CO2 STORED (MT)	65

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC

LEVEL 1 COST ESTIMATE SUMMARY



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY - VIKING

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	342.5	TRANSPORTATION	191.4
		FACILITIES	84.5
		WELLS	56.7
		OTHER	9.8
OPEX [C]	391.8	TRANSPORTATION	64.7
		FACILITIES	171.5
		WELLS	52.0
		OTHER	103.7
ABEX [D]	95.4	TRANSPORTATION	27.4
		FACILITIES	38.2
		WELLS	15.7
		OTHER	14.1
TOTAL	829.7	-	829.7

LEVEL 1 COST ESTIMATE SUMMARY

Category	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)	15.6	5.8	21.4	27.8
B. Post-Final Investment Decision (Post-FID)	226.7	15.8	242.5	314.7
C. Total Operating Expenditure (OPEX)	279.0	24.3	303.3	391.8
D. Abandonment (ABEX)	66.3	7.1	73.4	95.4
TOTAL COST (CAPEX, OPEX, ABEX)			640.6	**829.7**
COST CO2 INJECTED (£ PER TONNE)			£9.86	**£12.76**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	SITE 5: VIKING Minimum Viable Developmen	
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pale Blue Dot.

COSTAIN

AXIS WELL TECHNOLOGY

FROM CONCEPT TO COMPLETION

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	185	
Route Length Factor	1.05	
Pipeline Crossings	8	
Tee Structures	2	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	14.0	
Anode Spacing (m)	300	

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£697,500**
A1.1.1	Pre-FEED	Lump Sum	£200,000	LS	1.00	£200,000	£90,000	*Company Time Writing, Contractor Surveillance*	£290,000
A1.1.2	FEED	Lump Sum	£350,000	LS	1.00	£250,000	£157,500	*Company Time Writing, Contractor Surveillance*	£407,500
B. Post FID									
B1.1	**Transportation - Post FID**								**£76,770,756**
B1.1.1	Detailed Design	Lump Sum	£400,000	LS	1.00	£400,000	£100,000	*Company Time Writing, IVB, SIT, Insurance etc*	£500,000
B1.1.2	Procurement		-	-	-	-	-		**£53,088,256**
B1.1.2.2	Insurance and Certification	Pipeline from Barmston	-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.3	Geotechnical Testing	Pipeline route	£2,000	km	194	£388,500	£28,000	*Documentation etc*	£416,500
B1.1.2.4	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 508mm, WT 17.5mm*	£1,500	Te	26,318	£39,477,000	£2,368,620	*Logistics/Freight @ 6%*	£41,845,620
B1.1.2.5	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£20	m	194,250	£3,885,000	£233,100		£4,118,100
B1.1.2.6	*Procurement - Coating (Trunk)*	*Concrete Coating*	£30	m	194,250	£5,827,500	£349,650		£6,177,150
B1.1.2.7	*Procurement - Anodes (Trunk)*	*CP Protection*	£45	Each	648	£29,138	£1,748		£30,886
B1.1.3	Fabrication		-	-	-	-	-		**£23,182,500**
B1.1.3.1	SSIV	Subsea Isolation Valve Structure	£1,500,000	LS	1	£1,500,000	£100,000	*Contractor Surveillance*	£1,600,000
B1.1.3.2	*Spoolbase Fabrication*	*Coating Only (S Lay)*	£50	m	194,250	£9,712,500	£50,000	*Contractor Surveillance*	£9,762,500
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	8	£800,000	£20,000	*Contractor Surveillance*	£820,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	2	£10,000,000	£1,000,000		£11,000,000

Total (Excluding Contingency)		**£77,468,256**
Pre-FID Contingency (%)	**30%**	**£209,250**
Post-FID Contingency (%)	**30%**	**£23,031,227**
Total (Including Contingency)		**£100,708,732**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: CONSTRUCTION AND COMMISSIONING**	Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION
TITLE	SITE 5: VIKING Minimum Viable Development		
CLIENT	ETI		
REVISION	A1		
DATE	20/10/2016		

Pipeline	Trunk Pipeline(s)	Infield Pipeline(s)
Number	1	
Route Length (km)	185	
Route Length Factor	1.05	
Pipeline Crossings	8	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	14	
Anode Spacing (m)	300	
Landfall Required?	YES	

Landfall Cost	£25,000,000

Activity	Vessel	Dayrate (£)	Working Rate (m/hr)
Pipeline Route Survey	Survey Vessel	£100,000	750
Pipelay (Reel)	Reel Lay Vessel	£150,000	500
Pipelay (S-Lay)	S-Lay Vessel (14000Te)	£350,000	100
Trenching and Backfill	Ploughing Vessel	£100,000	400
Crossing Installation	Survey Vessel	£100,000	-
Spoolpiece Tie-ins	DSV	£150,000	-
Commissioning	Survey Vessel	£100,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-
Seabed Rectification	Jet Trencher	£100,000	-

No.	Activity	Breakdown	Vessel	Day Rate (£)	Days	Sub-Total (£)	Total Cost (£)
B. Post FID							
B1.1	**Transportation - Post FID**						
B1.1.4	**Construction and Commissioning**						
B1.1.4.1	Pipeline Route Survey	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,500,000
		Infield Operations			11	£1,100,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000	2	£700,000	£29,750,000
		Infield Operations			81	£28,350,000	
		Demobilisation			2	£700,000	
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000	2	£200,000	£2,800,000
		Infield Operations - 3 day per Crossing			24	£2,400,000	
		Demobilisation			2	£200,000	
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£200,000	£1,400,000
		Infield Operations			10	£1,000,000	
		Demobilisation			2	£200,000	
B1.1.4.5	Commissioning	Mobilisation	Survey Vessel	£100,000	2	£200,000	£600,000
		Infield Operations			2	£200,000	
		Demobilisation			2	£200,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	4	£600,000	£1,350,000
		Infield Operations -SSIV & Tees			3	£450,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Pipelay (Carrier)	Mobilisation	Pipe Carrier (1600Te)	£50,000	2	£100,000	£1,800,000
		Infield Operations - days per trip			32	£1,600,000	
		Demobilisation			2	£100,000	
B1.1.4.8	Seabed Rectification	Mobilisation	Jet Trencher	£100,000	2	£200,000	£1,400,000
		Infield Operations - days per trip			10	£1,000,000	
		Demobilisation			2	£200,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£4,060,000	£4,060,000
B1.1.4.9	Landfall		-	Lump Sum	-	£25,000,000	£25,000,000
					Total (Excluding Contingency)		**£69,660,000**
					Contingency	**30%**	**£20,898,000**
					Total (Including Contingency)		**£90,558,000**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 5: VIKING Minimum Viable Developmen
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

Facilities:
PROCUREMENT & FABRICATION

COSTS EXTRACTED FROM QUE$TOR

Exchange Rate (£:$) 1.50

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.2	**Facilities - Pre FID**								**£12,822,205**
A1.2.1	Pre-FEED	4 Legged Jacket, Topsides	£3,237,160	LS	1	£3,237,160	£1,456,722	*Company Time Writing, Contractor Surveillance*	£4,693,882
A1.2.2	FEED	4 Legged Jacket, Topsides	£5,605,740	LS	1	£5,605,740	£2,522,583	*Company Time Writing, Contractor Surveillance*	£8,128,323
B. Post FID									
B1.2	**Facilities - Post FID**								**£52,211,383**
B1.2.1	Detailed Design	4 Legged Jacket, Topsides	£10,000,000	LS	1	£10,000,000	£3,000,000	*Company Time Writing, IVB, SIT etc*	**£13,000,000**
B1.2.2	Procurement		-	-	-		-	-	**£10,529,694**
	Jacket	4 Legged Jacket	-	-	-		-	-	***£2,536,373***
B1.2.2.1.1	Insurance and Certification		-	-	-		£584,667	*Insurance and Certification*	£584,667
B1.2.2.1.2	*Jacket Steel*		£1,333	Te	726	£968,000	£58,080		£1,026,080
B1.2.2.1.3	*Piles*		£1,301	Te	507	£659,438	£39,566	*Logistics/Freight @ 6%*	£699,004
B1.2.2.1.4	*Anodes*		£3,685	Te	47	£173,211	£10,393		£183,603
B1.2.2.1.5	*Installation Aids*		£1,127	Te	36	£40,584	£2,435		£43,019
	Topsides		-	-	-		-	-	***£7,993,321***
B1.2.2.2.1	Insurance and Certification		-	-	-		£880,000	*Insurance and Certification*	£880,000
B1.2.2.2.2	*Primary Steel*		£1,087	Te	169	£183,647	£11,019		£194,665.47
B1.2.2.2.3	*Secondary Steel*		£900	Te	101	£90,900	£5,454		£96,354.00
B1.2.2.2.4	*Piping*		£10,733	Te	30	£322,000	£19,320		£341,320.00
B1.2.2.2.5	*Electrical*		£19,200	Te	15	£288,000	£17,280		£305,280.00
B1.2.2.2.6	*Instrumentation*		£36,333	Te	15	£545,000	£32,700		£577,700.00
B1.2.2.2.7	*Miscellaneous*		£8,800	Te	18	£158,400	£9,504		£167,904.00
B1.2.2.2.8	*Manifolding*		£14,733	Te	19	£279,933	£16,796		£296,729.33
B1.2.2.2.9	*Control and Communications*	*Sat Comms*	£460,733	Te	3	£1,382,200	£82,932		£1,465,132.00
B1.2.2.2.10	*General Utilities*	*Drainage, Diesal Storage etc*	£50,000	Te	2	£100,000	£6,000		£106,000.00
B1.2.2.2.11	*Vent Stack*	*Low Volume (venting done at beach)*	£6,933	Te	35	£242,667	£14,560	*Logistics/Freight @ 6%*	£257,226.67
B1.2.2.2.12	*Diesel Generators*	*Power Generation*	£52,067	Te	0	£0	£0		£0.00
B1.2.2.2.13	*Power Distribution*		£36,067	Te	5	£180,333	£10,820		£191,153.33
B1.2.2.2.14	*Emergency Power*		£34,733	Te	2	£69,467	£4,168		£73,634.67
B1.2.2.2.15	*Quarters and Helideck*	*50 Te Helideck plus TR*	£23,333	Te	70	£1,633,333	£98,000		£1,731,333.33
B1.2.2.2.16	*Crane*	*Mechanical Handling*	£19,267	Te	30	£578,000	£34,680		£612,680.00
B1.2.2.2.17	*Lifeboats*	*Freefall Lifeboats*	£24,400	Te	7	£170,800	£10,248		£181,048.00
B1.2.2.2.18	*Chemical Injection*	*Chemicals, Pumps, Storage*	£46,600	Te	10	£466,000	£27,960		£493,960.00
B1.2.2.2.19	*PLR*	*Pig Reciever*	£10,000	Te	2	£20,000	£1,200		£21,200.00
B1.2.2.2.20	*Heaters*	*CO2 Heating*	£300,000	Each		£0	£0		£0
	Power Supply - Cable+Onshore Tie-in	*Connection into Local Distribution*	£17,371,600	Each	0	£0	£0		£0
B1.2.3	Fabrication		-	-			-		**£6,259,132**
	Jacket		-	-			-		***£3,234,775***
B1.2.3.1	*Jacket Steel*		£3,245	m	726	£2,355,628	£141,338		£2,496,966
B1.2.3.2	*Piles*		£1,022	m	507	£518,154	£31,089	*Logistics/Freight @ 6%*	£549,243
B1.2.3.3	*Anodes*		£755	Each	47	£35,501	£2,130		£37,631
B1.2.3.4	*Installation Aids*		£3,955		36	£142,392	£8,544		£150,936
	Topsides		-		-		-	-	***£3,024,357***
B1.2.3.2.1	*Primary Steel*		£5,467	Te	169	£923,867	£55,432		£979,299
B1.2.3.2.2	*Secondary Steel*		£7,200	Te	101	£727,200	£43,632		£770,832
B1.2.3.2.3	*Equipment*		£1,513	Te	75	£113,500	£6,810		£120,310
B1.2.3.2.4	*Piping*		£14,867	Te	30	£446,000	£26,760	*Logistics/Freight @ 6%*	£472,760
B1.2.3.2.5	*Electrical*		£26,467	Te	15	£397,000	£23,820		£420,820
B1.2.3.2.6	*PLR*	*Pig Reciever*	£25,000	Te	2	£50,000	£3,000		£53,000
B1.2.3.2.7	*Miscellaneous*		£10,867	Te	18	£195,600	£11,736		£207,336
B1.2.4	Construction and Commissioning		-	-	-		-	-	**£22,422,557**
B1.2.4.1	Power Cable Installation	lump sum	£21,714,500	Each	0	£0	£0		£0
B1.2.4.2	Installation Spread	Jacket Installation	£596,206	Days	28	£16,693,768	£0	-	£16,693,768
B1.2.4.3	Installation Spread	Topsides Installation	£135,533	Days	7	£948,733	£0	-	£948,733
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.4	*Tug Transport - Jacket*	*Infield Operations*	£57,236	Days	16	£915,776	£0	-	£915,776
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.5	*Barge Transport - Jacket*	*Infield Operations*	£8,672	Days	56	£485,632	£0	-	£485,632
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.6	*Tug Transport - Topsides*	*Infield Operations*	£57,236	Days	30	£1,717,080	£0	-	£1,717,080
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.7	*Barge Transport - Topsides*	*Infield Operations*	£8,672	Days	70	£607,040	£0	-	£607,040
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
				Total (Excluding Contingency)					**£65,033,588**
				Pre-FID Contingency (%)				**30%**	**£3,846,662**
				Post-FID Contingency (%)				**30%**	**£15,663,415**
				Total (Including Contingency)					**£84,543,665**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 5: VIKING Minimum Viable Developmer
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

WELLS:
COST SUMMARY

Well Cost Summary (including 30% Contingency)		
Well Name	**Days**	**Well Cost (£,000)**
Year 0		
Platform Injector 1	68.3	26142.5
Platform Injector 2	61.8	23932.5
Monitoring Well 1 / Spare Injector		
Year 10		
Workover 1	25.2	10067.5
Local Sidetrack 1	57.9	20292.5
Local Sidetrack 2	62.9	21597.5
Year 40		
Abandonment Platform Injector 1	31.2	8970
Abandonment Platform Injector 2	24.7	6760
Abandonment Monitoring Well 1		
TOTAL	331.8	117762.5

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary	
Drilling Campaign	**Overhead (£MM)**
Platform Injector 1-2 + MW	3.60
Abandonment	1.85

OPEX Overhead Cost Summary	
OPEX Campaign	**Overhead (£MM)**
Workover + Local Sidetracks	3.60

Level 1 Cost Estimate Summary - Wells	
Total CAPEX (£MM)	56.7
Total OPEX (£MM)	52.0
Total ABEX (£MM)	15.7
TOTAL (£MM)	**124.4**

Wells Cost Estimate - Primary Cost Summary						
Activity	**Drilling Costs**			**Procurement Costs (£,000)**		**Total Cost (£,000)**
	Phase Rig Cost (£,000)	**Phase Spread Cost (£,000)**	**Contingency (£,000)**	**Procurement (£,000)**	**Contingency (£,000)**	
Development Wells - CAPEX Breakdown						
Platform Injector 1	5,250	8,375	3,938	6,600	1,980	26,143
Platform Injector 2	4,750	7,625	3,563	6,150	1,845	23,933
Monitoring Well 1 / Spare Injector						
Wells - OPEX Breakdown						
Workover	2,350	4,000	413	2,750	555	10,068
Local Platform Sidetrack 1	4,450	7,175	3,338	4,100	1,230	20,293
Local Platform Sidetrack 2	4,950	8,175	3,338	3,950	1,185	21,598
Wells - ABEX Breakdown						
Abandonment Platform Injector 1	2,400	3,600	1,800	900	270	8,970
Abandonment Platform Injector 2	1900	2850	1425	450	135	6760
Abandonment Monitoring Well 1						

CAPEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.9**
Detailed Design PM & E	2.0	0.2		2.2	30%	0.7	**2.9**
Procurement	9.2	0.9		10.1	30%	3.8	**13.9**
Construction and Commissioning (Drilling)	26.0	3.60	Well Management Fees, Insurance, Site Survey, Studies etc.	29.6	30%	7.5	**37.1**
Total	**39.2**	**4.9**	**-**	**44.1**	**-**	**12.6**	**56.7**

OPEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
OPEX	38.3	3.60	Well Management Fees, Insurance, Site Survey, Studies etc.	41.9	30%	10.1	**52.0**

ABEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
ABEX	10.3	1.85	Well Management Fees, Insurance, Site Survey, Studies etc.	12.1	30%	3.6	**15.7**

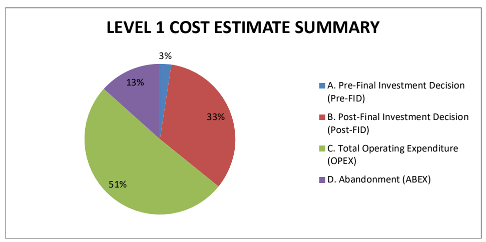
PROJECT	Strategic UK CCS Storage Appraisal
TITLE	Captain Subsea Option - MVD (No Goldeneye)
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

LEVEL 2 COST ESTIMATE

	Category	Comment	Responsibility	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**-**	**12.6**	**2.4**	**15.1**		**15.1**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	CU	0.6	0.2	0.8	0%	0.8
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	CU	0.2	0.1	0.3		0.3
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	AXIS	2.0	0.2	2.2		2.2
A1.4	**Other**			9.9	1.9	11.8		11.8
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	PBD	6.9	0.7	7.6		7.6
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	AXIS	0.0	0.0	0.0		0.0
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	PBD	2.0	0.2	2.2		2.2
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC		1.0	1.0	2.0		2.0
B. Post-Final Investment Decision (Post-FID)			**-**	**192.5**	**15.6**	**208.1**	**-**	**208.1**
B1.1	**Transportation**		-	45.7	1.2	46.9	-	46.9
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	CU	0.4	0.1	0.5	0%	0.5
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)		6.3	0.9	7.2		7.2
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc		2.2	0.2	2.4		2.4
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning		36.9	0.0	36.9		36.9
B1.2	**Facilities**		-	43.4	4.4	47.7	-	47.7
B1.2.1	Detailed Design	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	CU	0.3	0.1	0.3	0%	0.3
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc		43.1	4.3	47.4		47.4
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication		0.0	0.0	0.0		0.0
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC		0.0	0.0	0.0		0.0
B1.3	**Wells**		-	102.5	9.0	111.5	-	111.5
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	AXIS	2.0	0.2	2.2	0%	2.2
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc		16.0	1.6	17.7		17.7
B1.3.3	Fabrication	-		0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX		84.4	7.2	91.6		91.6
B1.4	**Other**		-	1.0	1.0	2.0	-	2.0
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	PBD	1.0	1.0	2.0	0%	2.0
C. Total Operating Expenditure (OPEX)			**-**	**296.9**	**19.7**	**316.6**	**-**	**316.6**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	CU	19.5	1.9	21.4	0%	21.4
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals		117.1	7.0	124.1		124.1
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	-	59.8	4.7	64.5		64.5
C1.4	**Other**			100.5	6.1	106.6	-	106.6
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	PBD	34.5	3.4	37.9	0%	37.9
C1.4.2	Financial Securities			26.0	2.6	28.65205479		28.7
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs		40.0	0.0	40		40.0
D. Abandonment (ABEX)			**-**	**77.4**	**5.6**	**83.0**	**-**	**83.0**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	CU	4.8	0.5	5.2	0%	5.2
D1.2	**Decommissioning - Facilities**	reverse install		3.0	0.3	3.3		3.3
D1.3	**Decommissioning - Wells**		AXIS	24.3	1.8	26.1		26.1
D1.4	**Other**		-	45.4	3.0	48.4	-	48.4
D1.4.1	Post Closure Monitoring	includes data management and interpretation	PBD	30.2	3.0	33.3	0%	33.3
D1.4.2	Handover	additional 10 years of coverage		15.1	0.0	15.1		15.1

FIELD LIFE (YEARS)	30
CO2 STORED (MT)	60

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC



Captain Subsea Option - MVD (No Goldeneye)

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	223.2	TRANSPORTATION	47.7
		FACILITIES	48.0
		WELLS	113.7
		OTHER	13.8
OPEX [C]	316.6	TRANSPORTATION	21.4
		FACILITIES	124.1
		WELLS	64.5
		OTHER	106.6
ABEX [D]	83.0	TRANSPORTATION	5.2
		FACILITIES	3.3
		WELLS	26.1
		OTHER	48.4
TOTAL	622.8	-	622.8

LEVEL 1 COST ESTIMATE SUMMARY

Category		Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		12.6	2.4	15.1	15.1
B. Post-Final Investment Decision (Post-FID)		192.5	15.6	208.1	208.1
C. Total Operating Expenditure (OPEX)		296.9	19.7	316.6	316.6
D. Abandonment (ABEX)		77.4	5.6	83.0	83.0
TOTAL COST (CAPEX, OPEX, ABEX)				622.8	**622.8**
COST CO2 INJECTED (£ PER TONNE)				£10.38	**£10.38**

PROJECT	Strategic UK CCS Storage Appraisal	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	aptain Subsea Option - MVD (No Goldeney	
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pale Blue Dot.

COSTAIN

AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	Trunk Pipeline(s)	Infield Pipeline - INJ1	Infield Pipeline - INJ2&3	
Number	**ACQUISITION OF A&C PIPELINE**	1	1	**inc spare**
Route Length (km)			26	**26**
Route Length Factor		1.05	1.05	
Pipeline Crossings			2	
Tee Structures		0	1	
Outer Diameter (mm)		323.9	323.9	
Wall Thickness (mm)		14.3	14.3	
Anode Spacing (m)		300	300	

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£697,500**
A1.1.1	Pre-FEED	Lump Sum	£200,000	LS	1.00	£200,000	£90,000	*Company Time Writing, Contractor Surveillance*	£290,000
A1.1.2	FEED	Lump Sum	£350,000	LS	1.00	£250,000	£157,500	*Company Time Writing, Contractor Surveillance*	£407,500
B. Post FID									
B1.1	**Transportation - Post FID**								**£10,044,491**
B1.1.1	Detailed Design	Lump Sum	£400,000	LS	1.00	£400,000	£100,000	*Company Time Writing, IVB, SIT, Insurance etc*	£500,000
B1.1.2	Procurement		-	-	-	-	-		**£7,165,491**
B1.1.2.1	Acquisition of Atlantic & Cromarty pipeline	16" & 4" Meg St Fergus - Atlantic	£1,200,000	LS	1.00	£1,200,000	£60,000	Cost of new pipeline = £100M	£1,260,000
B1.1.2.2	Insurance and Certification	Infield pipeline	-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.3	Geotechnical Testing	Infield pipeline	£2,000	km	27	£54,600	£28,000	*Documentation etc*	£82,600
B1.1.2.4	*Procurement - Linepipe (Infield)*	*API 5L X65, OD 406.4mm, WT 14.3mm*	£1,500	Te	2,981	£4,471,500	£268,290	*Logistics/Freight @ 6%*	£4,739,790
B1.1.2.5	*Procurement - Coating (Infield)*	*Corrosion Coating*	£20	m	27,300	£546,000	£32,760		£578,760
B1.1.2.6	*Procurement - Coating*	*Concrete Coating*	£30	m	0	£0	£0		£0
B1.1.2.7	*Procurement - Anodes*	*CP Protection*	£45	Each	91	£4,095	£246		£4,341
B1.1.3	Fabrication		-	-	-	-	-		**£2,379,000**
B1.1.3.1	SSIV	Subsea Isolation Valve Structure	£1,500,000	LS	0	£0	£100,000	*Contractor Surveillance*	£100,000
B1.1.3.2	*Spoolbase Fabrication*	*For reeling*	£50	m	27,300	£1,365,000	£50,000	*Contractor Surveillance*	£1,415,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	2	£200,000	£20,000	*Contractor Surveillance*	£220,000
B1.1.3.4	*Anode Skid Structure (every 2.5km)*	*For existing 78km pipeline*	£20,000	Each	31	£624,000	£20,000	*Contractor Surveillance*	£644,000

Total (Excluding Contingency)		**£10,741,991**
Pre-FID Contingency (%)	**0%**	**£0**
Post-FID Contingency (%)	**0%**	**£0**
Total (Including Contingency)		**£10,741,991**

PROJECT	Strategic UK CCS Storage Appraisal	**TRANSPORTATION: CONSTRUCTION AND COMMISSIONING**	Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION
TITLE	Captain Subsea Option - MVD (No Goldeneye)		
CLIENT	ETI		
REVISION	A1		
DATE	20/10/2016		

Pipeline	**Infield Pipeline - INJ1**	**Infield Pipeline - INJ2&3**
Number	1	1
Route Length (km)		26
Route Length Factor	1.05	1.05
Pipeline Crossings		2
Outer Diameter (mm)	323.9	323.9
Wall Thickness (mm)	14.3	14.3
Anode Spacing (m)	300	300
Landfall Required?	NO	-

Landfall Cost	£2,500,000	UMBILICAL

Activity	**Vessel**	**Dayrate (£)**	**Working Rate (m/hr)**
Pipeline Route Survey	Survey Vessel	£100,000	750
Pipelay (Reel)	Reel Lay Vessel	£150,000	500
Pipelay (S-Lay)	S-Lay Vessel (14000Te)	£350,000	100
Trenching and Backfill	Ploughing Vessel	£130,000	400
Crossing Installation	Survey Vessel	£100,000	-
Spoolpiece Tie-ins	DSV	£150,000	-
Commissioning	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-
Umbilical Installation	Construction Vessel	£150,000	500

No.	**Activity**	**Breakdown**	**Vessel**	**Day Rate (£)**	**Days**	**Sub-Total (£)**	**Total Cost (£)**
B. Post FID							
B1.1	**Transportation - Post FID**						
B1.1.4	**Construction and Commissioning**						
B1.1.4.1	Pipeline Route Survey	Mobilisation	Survey Vessel	£100,000	2	£200,000	£800,000
		Infield Operations			4	£400,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (Reel)	Mobilisation	Reel Lay Vessel	£150,000	12	£1,800,000	£2,700,000
		Infield Operations			3	£450,000	
		Demobilisation			3	£450,000	
B1.1.4.3	Structure Installation	Mobilisation	DSV	£150,000	3	£450,000	£1,950,000
		Infield Operations - Manifold + Crossings			9	£1,350,000	
		Demobilisation			1	£150,000	
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£300,000	£2,100,000
		Infield Operations - 6 off			10	£1,500,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£2,400,000
		Infield Operations			12	£1,800,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	12	£1,800,000	£6,000,000
		Infield Operations -Anode Skids & Tee			16	£2,400,000	
		Demobilisation			12	£1,800,000	
B1.1.4.7	Umbilical Installation	Mobilisation	Construction Vessel	£150,000	4	£600,000	£2,875,000
		Infield Operations			11.2	£1,675,000	
		Demobilisation			4	£600,000	
B1.1.4.8	Trenching and Backfill	Mobilisation	Ploughing Vessel	£130,000	3	£450,000	£9,000,000
		Infield Operations			55	£8,250,000	
		Demobilisation			2	£300,000	
B1.1.4.9	Mattress Installation (Anode Skid Protection)	Mobilisation	Survey Vessel	£100,000	4	£400,000	£1,600,000
		Infield Operations			8	£800,000	
		Demobilisation			4	£400,000	
B1.1.4.10	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£2,942,500	£2,942,500
B1.1.4.11	A&C pipeline prep - inspection, intelligent pigging etc.		-	Lump Sum	-	£2,000,000	£2,000,000
B1.1.4.12	Landfall - Umbilical (HDD)		-	Lump Sum	-	£2,500,000	£2,500,000
					Total (Excluding Contingency)		**£36,867,500**
					Contingency		
					Total (Including Contingency)		**£36,867,500**

PROJECT	Strategic UK CCS Storage Appraisal	
TITLE	Captain Subsea Option - MVD (No Goldeneye	**Facilities:** **PROCUREMENT & FABRICATION**
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

COSTS EXTRACTED FROM QUE$TOR

Exchange Rate (£:$) **1.50**

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.2	**Facilities - Pre FID**								**£290,000**
A1.2.1	Pre-FEED	Manifold, Umbilical	£100,000	LS	1	£100,000	£45,000	*Company Time Writing, Contractor Surveillance*	£145,000
A1.2.2	FEED	Manifold, Umbilical	£100,000	LS	1	£100,000	£45,000	*Company Time Writing, Contractor Surveillance*	£145,000
B. Post FID									
B1.2	**Facilities - Post FID**								**£47,735,000**
B1.2.1	Detailed Design	Manifold, Umbilical	£250,000	LS	1	£250,000	£75,000	*Company Time Writing, IVB, SIT etc*	**£325,000**
B1.3.1	Procurement		-	-	-		-	-	**£47,410,000**
	Manifold	Manifold	£1,500,000	LS	1	£1,500,000	£150,000	*Company Time Writing, IVB, SIT, etc*	£1,650,000
	EHC Umbilical from Beach	*Electrical Power, Hydraulics, Chemicals*	£400	per m	78,000	£31,200,000	£3,120,000	*Company Time Writing, IVB, SIT, etc*	£34,320,000
	Infield Umbilcal	*Electrical Power, Hydraulics, Chemicals*	£400	per m	26,000	£10,400,000	£1,040,000	*Company Time Writing, IVB, SIT, etc*	£11,440,000
B1.3.3	Fabrication	COVERED WITHIN TRANSPORTATION	-	-	-		-		**COVERED IN TRANSPORTATION**

Total (Excluding Contingency)		**£48,025,000**
Pre-FID Contingency (%)	**0%**	**£0**
Post-FID Contingency (%)	**0%**	**£0**
Total (Including Contingency)		**£48,025,000**

PROJECT	Strategic UK CCS Storage Appraisal
TITLE	aptain Subsea Option - MVD (No Goldeney
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

WELLS: COST SUMMARY

Well Cost Summary		
Well Name	**Days**	**Well Cost (£,000)**
	Year 0	
Subsea Injector 1		
Subsea Injector 2		
Relief Well		
	Year 10	
Local Platform Sidetrack 1		
Local Platform Sidetrack 2		
	Year 20	
Subsea Injector 3		
Subsea Injector 4 Spare		
Monitoring Well 1 / Spare Injector		
	Year 30	
Local Platform Sidetrack 3		
Local Platform Sidetrack 4		
	Year 40	
Abandonment Subsea Injector 1		
Abandonment Subsea Injector 2		
Abandonment Relief Well		
Abandonment Subsea Injector 3		
Abandonment Subsea Injector 4 Spare		
Abandonment Monitoring Well 2		
TOTAL	0.0	0.0

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary	
Drilling Campaign	**Overhead (£MM)**
Platform Injector 1-2 + RW	3.60
Platform Injector 3-4	3.60
Abandonment	1.80

OPEX Overhead Cost Summary	
OPEX Campaign	**Overhead (£MM)**
Local Platform Sidetrack 1	1.50
Local Platform Sidetrack 2	1.05
Local Platform Sidetrack 3	1.05
Local Platform Sidetrack 4	1.05

Wells Cost Estimate - Primary Cost Summary

Activity	Drilling Costs			Procurement Costs (£,000)		Total Cost (£,000)	30% FOR SUBSEA WELLS
	Phase Rig Cost (£,000)	Phase Spread Cost (£,000)	Contingency (£,000)	Procurement (£,000)	Contingency (£,000)		
Development Wells - CAPEX Breakdown							1.3
Subsea Injector 1		22,800	0	6,800	0	29,600	
Subsea Injector 2		21,066	0	6,372	0	27,438	
Relief Well							
Subsea Injector 3		21,066	0	6,372	0	27,438	
Subsea Injector 4 Spare							
Monitoring Well 1 / Spare Injector							
Wells - OPEX Breakdown							
Local Subsea Sidetrack 1	5,985	7,400	0	3,700	0	17,085	
Local Subsea Sidetrack 2	5,985	7,650	0	3,250	0	16,885	
Local Subsea Sidetrack 3	5,985	7,900	0	2,800	0	16,685	
Local Subsea Sidetrack 4							
Wells - ABEX Breakdown							
Abandonment Subsea Injector 1	2,926	3,300	0	900	0	7,126	
Abandonment Subsea Injector 2	2926	3300	0	450	0	6676	
Abandonment Relief Well							
Abandonment Subsea Injector 3	2926	3300	0	450	0	6676	
Abandonment Subsea Injector 4 Spare							
Abandonment Monitoring Well 2							

CAPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	0%	0.0	**2.2**
Detailed Design PM & E	2.0	0.2		2.2	0%	0.0	**2.2**
Procurement	16.0	1.6		17.7	0%	0.0	**17.7**
Construction and Commissioning (Drilling)	84.4	7.20	Well Management Fees, Insurance, Site Survey, Studies etc.	91.6	0%	0.0	**91.6**
Total	**104.5**	**9.2**		**113.7**	**-**	**0.0**	**113.7**

OPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
OPEX	59.8	4.65	Well Management Fees, Insurance, Site Survey, Studies etc.	64.5	0%	0.0	**64.5**

ABEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
ABEX	24.3	1.80	Well Management Fees, Insurance, Site Survey, Studies etc.	26.1	0%	0.0	**26.1**

Level 1 Cost Estimate Summary - Wells	
Total CAPEX (£MM)	113.7
Total OPEX (£MM)	64.5
Total ABEX (£MM)	26.1
TOTAL (£MM)	**204.2**

PROJECT	CALEDONIA CLEAN ENERGY PROJECT (CCEP)	**OPEX: TRANSPORTATION**
TITLE	OPEX Estimate	
CLIENT	ETI	
REVISION	A1	
DATE	27/05/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline(s)	**Existing Atlantic & Cromarty**	**Infield Pipelines**
Number	1	3
Total Route Length (km)	78	26
Design Life (Yrs)	30	30

Assumptions and Cost Basis		
OPEX	**Cost Basis and Assumptions**	
External Inspection (ROV)	Survey Vessel c/w ROV (DAYRATE)	£100,000
Internal Inspection (intelligent pigging)	DSV	£150,000
	Equipment Hire/Mobilisation Costs	£500,000
Maintenance & Repair	General Allowance Annual	£100,000

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. OPEX - Transportation									
A1	External Inspection (ROV)	Every 5 years	£100,000	Day	38.67	£3,866,667	£386,667	*Engineering support @ 10%*	£4,253,333
A2	Internal Inspection (intelligent pigging)	14 day campaign every 5 yrs	£150,000	Day	84.00	£12,600,000	£1,260,000	*Engineering support @ 10%*	£13,860,000
A3	Maintenance & Repair	General Allowance - £100k/year	£100,000	LS	30	£3,000,000	£300,000	*Engineering support @ 10%*	£3,300,000
						Total (Excluding Contingency)			**£21,413,333**
						Contingency (%)		**0%**	**£0**
						Total Transportation OPEX (Including Contingency)			**£21,413,333**
						Average Yearly OPEX			**£713,778**

PROJECT	Strategic UK CCS Storage Appraisal	
TITLE	Captain Subsea Option - MVD (No Goldeneye)	**OPEX: FACILITIES**
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pale Blue Dot. COSTAIN

Assumptions and Cost Basis

OPEX	Cost Basis and Assumptions		
Offshore Core Crew	n/a	-	
Onshore Resourcing	Staff rate per day (team of 5)	£750	day
Annual inspection of drill centre	Survey Vessel c/w ROV (dayrate)	£100,000	day
Campaign for minor intervention - 2 years	DSV (dayrate)	£150,000	day
Campaign for major intervention - 10 years	DSV (dayrate)	£150,000	day
	Equipment Replacement (nominal sum)	£1,000,000	10 year
Relief well monitoring - 6 months	3 day DSV Campaign	£150,000	day
Chemicals	MEG	£750	m3
	Methanol	£300	m3
	Controls/Hydraulic Fluid	£1,000	200LTR
Insurance	General Allowance of £100k per year	£100,000	Yr

Design Life (Yrs)	**30**

No.	Item	Description	Unit Cost (£)	Unit	Qty	Sub-Total OPEX (£)	Overhead (£)	Description (Overheads)	Annual OPEX (£)	Total OPEX (£)
B. OPEX - Facilities										
B1	Offshore Core Crew	Not applicable (subsea)	£0	-	£0	£0	£0	-		£0
B2	Onshore Resourcing	Staff rate per day (team of 5)	£750	staff days	54,750	£41,062,500	£0	-	£821,250	£41,062,500
B3	Subsea Intervention Activities									
B3.1	Annual inspection of drill centre	5 day Survey vessel campaign every year	£100,000	day	150.0	£15,000,000	£1,500,000	Engineering Support @ 10%	£550,000	£16,500,000
B3.3	Campaign for minor intervention - 2 years	7 day DSV campaign every 2 years	£100,000	day	105.0	£10,500,000	£1,050,000	Engineering Support @ 10%	£385,000	£11,550,000
B3.4	Campaign for major intervention - 10 years	30 day DSV campaign every 10 years	£150,000	day	90.0	£13,500,000	£1,350,000	Engineering Support @ 10%	£495,000	£14,850,000
		Equipment	£1,000,000	LS	3.00	£3,000,000	£180,000	Logistics/Freight @ 6%	£106,000	£3,180,000
B3.5	Relief well monitoring - 6 months	3 day DSV campaign every 6 month	£150,000	day	180.00	£27,000,000	£2,700,000	Engineering Support @ 10%	£990,000	£29,700,000
B4	Chemicals									
B4.1	Chemicals - MEG	2m3/well/warm start up (12 per year) and 5m3/well cold start up (1 per year)	£750	m3	3480.0	£2,610,000	£156,600	Logistics/Freight @ 6%	£92,220	£2,766,600
B4.2	Chemicals - Methanol		£300	m3	3480.0	£1,044,000	£62,640	Logistics/Freight @ 6%	£36,888	£1,106,640
B4.3	Chemicals - Hydraulic Fluid	200 ltr a month	£1,000	200LTR	360.0	£360,000	£21,600	Logistics/Freight @ 6%	£12,720	£381,600
B5	Insurance	General Allowance of £100k per year	£100,000	LS	30	£3,000,000	£0	-	£100,000	£3,000,000

Total (Excluding Contingency)		**£124,097,340**
Contingency (%)	**0%**	**£0**
Total (Including Contingency)		**£124,097,340**
Average Yearly OPEX		**£4,136,578.00**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 19: HAMILTON Minimum Viable Development
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

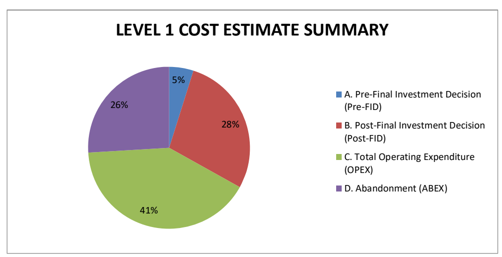
LEVEL 2 COST ESTIMATE

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Responsibility	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**-**	**8.5**	**2.3**	**10.7**		**14.0**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	CU	0.3	0.1	0.4		0.5
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	CU	1.3	0.6	1.9		2.5
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	AXIS	2.0	0.2	2.2		2.9
A1.4	**Other**			4.9	1.4	6.3	30%	8.2
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	PBD	1.9	0.2	2.1		2.7
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s) - Not Required	AXIS	0.0	0.0	0.0		0.0
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	PBD	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC		1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**-**	**54.1**	**8.0**	**62.1**	**-**	**80.2**
B1.1	**Transportation**		-	7.9	0.9	8.9	-	11.5
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System		0.3	0.2	0.5		0.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	CU	0.1	0.5	0.6	30%	0.8
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc		1.5	0.2	1.7		2.2
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning		6.1	0.0	6.1		7.9
B1.2	**Facilities**		-	16.9	2.4	19.3	-	25.0
B1.2.1	Detailed Design			2.0	0.6	2.6		3.4
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	CU	0.0	1.8	1.8	30%	2.3
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication		0.0	0.0	0.0		0.0
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC		14.9	0.0	14.9		19.4
B1.3	**Wells**		-	28.3	3.7	32.0	-	41.1
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)		2.0	0.2	2.2		2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc		9.3	0.9	10.2		13.0
B1.3.3	Fabrication	-	AXIS	0.0	0.0	0.0	30%	0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX		17.1	2.6	19.6		25.2
		Gas Injector 1 and 2 + Spare Well		17.1	2.6	19.6		25.2
		Dense Phase Injector 1 and 2		0.0	0.0	0.0		0.0
B1.4	**Other**		-	1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	PBD	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**-**	**80.5**	**9.3**	**89.7**	**-**	**116.5**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)		5.0	0.3	5.3		6.9
C1.2	**OPEX - Facilities**		CU	44.0	4.0	48.0		62.4
C1.2.1	OPEX - Offshore Facilities	Manning, Power, IMR, Chemicals		44.0	4.0	48.0		62.4
C1.2.2	OPEX - Power Supply	Power supply from Beach				0.0		0.0
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	-	5.6	2.4	8.0		10.2
C1.3.1	**Well Sidetracks and Workovers**	Local Sidetrack 1		0.0	0.0	0.0	30%	0.0
		Gas Injector Workover 1		5.6	1.4	6.9		8.8
		Gas Injector Workover 2	AXIS	0.0	1.1	1.1		1.4
		Local Sidetrack 2		0.0	0.0	0.0		0.0
		Local Sidetrack 3		0.0	0.0	0.0		0.0
		Local Sidetrack 4		0.0	0.0	0.0		0.0
C1.4	**Other**			25.9	2.6	28.4737457	-	37.0
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation		7.4	0.7	8.14		10.6
C1.4.2	Financial Securities		PBD	18.5	1.8	20.3337457	30%	26.4
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs		0.0	0.0	0		0.0
D. Abandonment (ABEX)			**-**	**50.4**	**6.5**	**56.9**	**-**	**73.9**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	CU	1.2	0.1	1.3		1.7
D1.2	**Decommissioning - Facilities**	Que$tor		27.7	2.8	30.5	30%	39.7
D1.3	**Decommissioning - Wells**		AXIS	8.1	2.7	10.8		14.0
D1.4	**Other**		-	13.4	0.9	14.24	-	18.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	PBD	8.9	0.9	9.79	30%	12.7
D1.4.2	Handover	additional 10 years of coverage		4.5	0.0	4.45		5.8

FIELD LIFE (YEARS)	8
CO2 STORED (MT)	12

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	94.2	TRANSPORTATION	12.0
		FACILITIES	27.5
		WELLS	43.9
		OTHER	10.8
OPEX [C]	116.5	TRANSPORTATION	6.9
		FACILITIES	62.4
		WELLS	10.2
		OTHER	37.0
ABEX [D]	73.9	TRANSPORTATION	1.7
		FACILITIES	39.7
		WELLS	14.0
		OTHER	18.5
TOTAL	284.6	-	284.6

LEVEL 1 COST ESTIMATE SUMMARY

Category		Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		8.5	2.3	10.7	14.0
B. Post-Final Investment Decision (Post-FID)		54.1	8.0	62.1	80.2
C. Total Operating Expenditure (OPEX)		80.5	9.3	89.7	116.5
D. Abandonment (ABEX)		50.4	6.5	56.9	73.9
TOTAL COST (CAPEX, OPEX, ABEX)				219.4	**284.6**
COST CO2 INJECTED (£ PER TONNE)				£18.28	**£23.71**

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18484180

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	E 19: HAMILTON Minimum Viable Developm	
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	0.3	
Route Length Factor	1.05	
Pipeline Crossings		
Tee Structures	0	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	21.4	
Anode Spacing (m)	500	

No.	**Item**	**Description**	**Unit Cost (£)**	**Unit**	**Qty**	**Total (£MM)**	**Overhead (£)**	**Description (Overheads)**	**Total Cost (£)**
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£562,500**
A1.1.1	Pre-FEED	Lump Sum	£100,000	LS	1.00	£200,000	£45,000	*Company Time Writing, Contractor Surveillance*	£245,000
A1.1.2	FEED	Lump Sum	£150,000	LS	1.00	£250,000	£67,500	*Company Time Writing, Contractor Surveillance*	£317,500
B. Post FID									
B1.1	**Transportation - Post FID**								**£2,794,441**
B1.1.1	Detailed Design	Lump Sum	£250,000	LS	1.00	£250,000	£200,000	*Company Time Writing, IVB, SIT, Insurance etc*	£450,000
B1.1.2	Procurement		-	-	-	-	-		**£638,691**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	0	£630	£28,000	*Documentation etc*	£28,630
B1.1.2.3	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 406.4mm, WT 21.4mm*	£1,500	Te	65	£97,500	£5,850	*Logistics/Freight @ 6%*	£103,350
B1.1.2.4	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£20	m	315	£6,300	£378		£6,678
B1.1.2.5	*Procurement - Coating (Trunk)*	*Concrete Coating*	£30	m	0	£0	£0		£0
B1.1.2.6	*Procurement - Anodes (Trunk)*	*CP Protection*	£50	Each	1	£32	£2		£33
B1.1.3	Fabrication		-	-	-	-	-		**£1,705,750**
B1.1.3.1	SSIV	Subsea Isolation Valve Structure	£1,500,000	LS	1	£1,500,000	£100,000	*Contractor Surveillance*	£1,600,000
B1.1.3.2	*Spoolbase Fabrication*	*Coating Only (S Lay)*	£50	m	315	£15,750	£50,000	*Contractor Surveillance*	£65,750
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	0	£0	£20,000	*Contractor Surveillance*	£20,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	0	£0	£20,000	*Contractor Surveillance*	£20,000

Total (Excluding Contingency)		**£3,356,941**
Pre-FID Contingency (%)	**30%**	**£168,750**
Post-FID Contingency (%)	**30%**	**£838,332**
Total (Including Contingency)		**£4,364,024**

PROJECT	Strategic UK Storage Appraisal Project	TRANSPORTATION: CONSTRUCTION AND COMMISSIONING
TITLE	E 19: HAMILTON Minimum Viable Develop	
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	Trunk Pipeline(s)	Infield Pipeline(s)
Number	1	
Route Length (km)	0.3	
Route Length Factor	1.05	
Pipeline Crossings		
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	21.4	
Anode Spacing (m)	500	
Landfall Required?	YES	-

Activity	Vessel	Dayrate (£)	Working Rate (m/hr)
Pipeline Route Survey	Survey Vessel	£100,000	750
Pipelay (Reel)	Reel Lay Vessel	£150,000	500
Pipelay (S-Lay)	S-Lay Vessel (14000Te)	£350,000	100
Trenching and Backfill	Ploughing Vessel	£100,000	400
Crossing Installation	Survey Vessel	£100,000	-
Spoolpiece Tie-ins	DSV	£150,000	-
Commissioning	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-

Landfall Cost		Landfall and Onshore tie-in for Pipeline

No.	Activity	Breakdown	Vessel	Day Rate (£)	Days	Sub-Total (£)	Total Cost (£)
B. Post FID							
B1.1	Transportation - Post FID						
B1.1.4	Construction and Commissioning						
B1.1.4.1	Pipeline Route Survey	Mobilisation	Survey Vessel	£100,000	2	£200,000	£500,000
		Infield Operations			1	£100,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000			
		Infield Operations					
		Demobilisation					
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000			
		Infield Operations - 3 day per Crossing					
		Demobilisation					
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£300,000	£2,100,000
		Infield Operations			10	£1,500,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	2	£300,000	£750,000
		Infield Operations -SSIV			1	£150,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Trenching and Backfill	Mobilisation	Ploughing Vessel	£100,000	3	£300,000	£509,375
		Infield Operations			0	£9,375	
		Demobilisation			2	£200,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£550,938	£550,938
B1.1.4.9	Landfall and Onshore tie-in for Pipeline		-	Lump Sum	-		
					Total (Excluding Contingency)		£6,060,313
					Contingency	30%	£1,818,094
					Total (Including Contingency)		£7,878,406

PROJECT	Strategic UK Storage Appraisal Project	
TITLE	E 19: HAMILTON Minimum Viable Developn	**Facilities: PROCUREMENT & FABRICATION**
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

COSTS EXTRACTED FROM QUE$TOR

Exchange Rate (£:$) **1.50**

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.2	**Facilities - Pre FID**								**£1,885,000**
A1.2.1	Pre-FEED	3 Legged Jacket, Topsides, Power Cable	£300,000	LS	1	£300,000	£135,000	*Company Time Writing, Contractor Surveillance*	£435,000
A1.2.2	FEED	3 Legged Jacket, Topsides, Power Cable	£1,000,000	LS	1	£1,000,000	£450,000	*Company Time Writing, Contractor Surveillance*	£1,450,000
B. Post FID									
B1.2	**Facilities - Post FID**								**£19,259,817**
B1.2.1	Detailed Design	3 Legged Jacket, Topsides, Power Cable	£2,000,000	LS	1	£2,000,000	£600,000	*Company Time Writing, IVB, SIT etc*	**£2,600,000**
B1.2.2	Procurement		-	-	-		-	-	**£1,754,667**
	Jacket	3 Legged Jacket	-	-	-		-	-	***£394,000***
B1.2.2.1.1	Insurance and Certification		-	-	-		£394,000	*Insurance and Certification*	£394,000
B1.2.2.1.2	*Jacket Steel*		£1,333	Te		£0	£0		£0
B1.2.2.1.3	*Piles*		£1,301	Te		£0	£0	*Logistics/Freight @ 6%*	£0
B1.2.2.1.4	*Anodes*		£3,685	Te		£0	£0		£0
B1.2.2.1.5	*Installation Aids*		£1,127	Te		£0	£0		£0
	Topsides		-	-			-	-	***£1,360,667***
B1.2.2.2.1	Insurance and Certification		-	-			£1,360,667	*Insurance and Certification*	£1,360,667
B1.2.2.2.2	*Primary Steel*		£1,087	Te		£0	£0		£0.00
B1.2.2.2.3	*Secondary Steel*		£900	Te		£0	£0		£0.00
B1.2.2.2.4	*Piping*		£10,733	Te		£0	£0		£0.00
B1.2.2.2.5	*Electrical*		£19,200	Te		£0	£0		£0.00
B1.2.2.2.6	*Instrumentation*		£36,333	Te		£0	£0		£0.00
B1.2.2.2.7	*Miscellaneous*		£8,800	Te		£0	£0		£0.00
B1.2.2.2.8	*Manifolding*		£14,733	Te		£0	£0		£0.00
B1.2.2.2.9	*Control and Communications*	*Sat Comms*	£460,733	Te		£0	£0		£0.00
B1.2.2.2.10	*General Utilities*	*Drainage, Diesel Storage etc*	£50,000	Te		£0	£0		£0.00
B1.2.2.2.11	*Vent Stack*	*Low Volume (venting done at beach)*	£6,933	Te		£0	£0	*Logistics/Freight @ 6%*	£0.00
B1.2.2.2.12	*Diesel Generators*	*Power Generation*	£52,067	Te		£0	£0		£0.00
B1.2.2.2.13	*Power Distribution*		£36,067	Te		£0	£0		£0.00
B1.2.2.2.14	*Emergency Power*		£34,733	Te		£0	£0		£0.00
B1.2.2.2.15	*Quarters and Helideck*	*50 Te Helideck plus TR*	£23,333	Te		£0	£0		£0.00
B1.2.2.2.16	*Crane*	*Mechanical Handling*	£19,267	Te		£0	£0		£0.00
B1.2.2.2.17	*Lifeboats*	*Freefall Lifeboats*	£24,400	Te		£0	£0		£0.00
B1.2.2.2.18	*Chemical Injection*	*Chemicals, Pumps, Storage*	£46,600	Te		£0	£0		£0.00
B1.2.2.2.19	*PLR*	*Pig Receiver*	£10,000	Te		£0	£0		£0.00
B1.2.2.2.20	*Heaters*	*CO2 Heating*	£300,000	Each		£0	£0		£0
	Power Supply - Cable+Onshore Tie-in	*Connection into Local Distribution*	£7,771,600	Each		£0	£0		£0
B1.2.3	Fabrication		-	-			-		**£0**
	Jacket		-	-			-		***£0***
B1.2.3.1	*Jacket Steel*		£3,245	Te		£0	£0		£0
B1.2.3.2	*Piles*		£1,022	Te		£0	£0	*Logistics/Freight @ 6%*	£0
B1.2.3.3	*Anodes*		£755	Te		£0	£0		£0
B1.2.3.4	*Installation Aids*		£3,955	Te		£0	£0		£0
	Topsides		-				-	-	***£0***
B1.2.3.2.1	*Primary Steel*		£5,467	Te		£0	£0		£0
B1.2.3.2.2	*Secondary Steel*		£7,200	Te		£0	£0		£0
B1.2.3.2.3	*Equipment*		£1,513	Te		£0	£0		£0
B1.2.3.2.4	*Piping*		£14,867	Te		£0	£0	*Logistics/Freight @ 6%*	£0
B1.2.3.2.5	*Electrical*		£26,467	Te		£0	£0		£0
B1.2.3.2.6	*PLR*	*Pig Receiver*	£25,000	Te		£0	£0		£0
B1.2.3.2.7	*Miscellaneous*		£10,867	Te		£0	£0		£0
B1.2.4	Construction and Commissioning		-	-			-	-	**£14,905,150**
B1.2.4.1	Power Cable Installation	lump sum	£9,714,500	Each		£0	£0		£0
B1.2.4.2	Installation Spread	Jacket Installation	£596,206	Days	25	£14,905,150	£0	-	£14,905,150
B1.2.4.3	Installation Spread	Topsides Installation	£135,533	Days		£0	£0	-	£0
B1.2.4.4	*Tug Transport - Jacket*	*Mobilisation*	£57,236	Days		£0	£0	-	£0
		Infield Operations	£57,236	Days		£0	£0	-	£0
		Demobilisation	£57,236	Days		£0	£0	-	£0
B1.2.4.5	*Barge Transport - Jacket*	*Mobilisation*	£8,672	Days		£0	£0	-	£0
		Infield Operations	£8,672	Days		£0	£0	-	£0
		Demobilisation	£8,672	Days		£0	£0	-	£0
B1.2.4.6	*Tug Transport - Topsides*	*Mobilisation*	£57,236	Days		£0	£0	-	£0
		Infield Operations	£57,236	Days		£0	£0	-	£0
		Demobilisation	£57,236	Days		£0	£0	-	£0
B1.2.4.7	*Barge Transport - Topsides*	*Mobilisation*	£8,672	Days		£0	£0	-	£0
		Infield Operations	£8,672	Days		£0	£0	-	£0
		Demobilisation	£8,672	Days		£0	£0	-	£0
				Total (Excluding Contingency)					**£21,144,817**
				Pre-FID Contingency (%)				**30%**	**£565,500**
				Post-FID Contingency (%)				**30%**	**£5,777,945**
				Total (Including Contingency)					**£27,488,262**

PROJECT	Strategic UK Storage Appraisal Project	**WELLS: COST SUMMARY**
TITLE	E 19: HAMILTON Minimum Viable Developn	
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pale Blue Dot.

COSTAIN

AXIS WELL TECHNOLOGY

FROM CONCEPT TO COMPLETION

Well Cost Summary (including 30% Contingency)

Well Name	Days	Well Cost (£,000)
Year 0		
Gas Injector 1	45.5	16,625.0
Gas Injector 2	39.0	14,550.0
Spare Well		
Year 7		
Local Sidetrack 1		
Year 13		
Gas Injector Workover 1		
Gas Injector Workover 2		
Year 15		
Local Sidetrack 2		
Local Sidetrack 3		
Year 17		
Dense Phase Injector 3		
Dense Phase Injector 4		
Year 20		
Local Sidetrack 4		
Year 25		
Abandonment Gas Injector 1	20.8	6,100.0
Abandonment Gas Injector 2	14.3	4,025.0
Abandonment Dense Phase Injector 3		
Abandonment Dense Phase Injector 4		
Abandonment Monitoring Well		
TOTAL	119.6	41300

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary

Drilling Campaign	Overhead (£MM)
Gas Injector 1 and 2 + Spare Well	2.55
Dense Phase Injector 1 and 2	

OPEX Overhead Cost Summary

OPEX Campaign	Overhead (£MM)
Local Sidetrack 1	
Gas Injector Workover 1	1.35
Gas Injector Workover 2	1.05
Local Sidetrack 2	
Local Sidetrack 3	
Local Sidetrack 4	

Wells Cost Estimate - Primary Cost Summary

Activity	Drilling Costs			Procurement Costs (£,000)		Total Cost (£,000)
	Phase Rig Cost (£,000)	Phase Spread Cost (£,000)	Contingency (£,000)	Procurement (£,000)	Contingency (£,000)	
Development Wells - CAPEX Breakdown						
Gas Injector 1	3500	5650	2625	4850	1455	18080
Gas Injector 2	3000	4900	2250	4400	1320	15870
Spare Well						
Dense Phase Injector 3						
Dense Phase Injector 4						
Wells - OPEX Breakdown						
Local Sidetrack 1						
Gas Injector Workover 1	2050	3500	1537.5	2050	615	9752.5
Gas Injector Workover 2						
Local Sidetrack 2						
Local Sidetrack 3						
Local Sidetrack 4						
Wells - ABEX Breakdown						
Abandonment Gas Injector 1	1600	2400	1200	900	270	6370
Abandonment Gas Injector 2	1100	1650	825	450	135	4160
Abandonment Dense Phase Injector 3						
Abandonment Dense Phase Injector 4						
Abandonment Monitoring Well						

	CAPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
A1.3	Pre-FEED / FEED PM & E	2	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.9**
B1.3.1	Detailed Design PM & E	2	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	9.3	0.9	Trees, Gauges etc.	10.2	30%	2.8	**13.0**
B1.3.4	Construction and Commissioning (Drilling)	17.1	2.55	Well Management Fees, Insurance, Site Survey, Studies etc.	19.6	30%	5.6	**25.2**
	Total	30.3	3.9	-	34.2		9.7	**43.9**

OPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
OPEX	7.6	2.40	Well Management Fees, Insurance, Site Survey, Studies etc.	10.0	30%	2.9	**12.9**

ABEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
ABEX	8.1	2.7	Well Management Fees, Insurance, Site Survey, Studies etc.	10.8	30%	2.4	**13.2**

Level 1 Cost Estimate Summary - Wells

	Total CAPEX (£MM)	43.9
C1.3	Total OPEX (£MM)	12.9
D1.3	Total ABEX (£MM)	13.2
	TOTAL (£MM)	**70.0**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 2: FORTIES 5 - SOUTH SITE
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

LEVEL 2 COST ESTIMATE

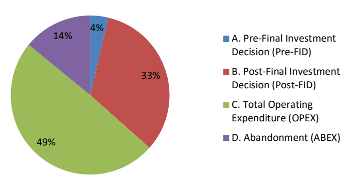
Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**53.6**	**6.0**	**59.6**		**72.8**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.6	0.3	0.9		1.1
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	4.5	2.0	6.5		8.5
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	2.0	0.2	2.2		2.9
A1.4	**Other**		46.5	3.5	50.1	30%	60.4
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	14.1	1.4	15.5		20.1
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	29.5	0.9	30.4		34.7
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**495.6**	**31.1**	**526.7**	**-**	**650.5**
B1.1	**Transportation**		206.8	7.0	213.8	-	277.9
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.0	0.2	1.2		1.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	102.1	6.6	108.7	30%	141.4
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	23.5	0.2	23.7		30.8
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	80.1	0.0	80.1		104.1
B1.2	**Facilities**		60.8	7.6	68.4	-	88.9
B1.2.1	Detailed Design	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	10.0	3.0	13.0		16.9
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	14.2	3.7	17.9	30%	23.3
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	14.2	0.8	15.0		19.5
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	22.4	0.0	22.4		29.1
B1.3	**Wells**		227.1	15.5	242.6	-	281.2
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	2.0	0.2	2.2		2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	38.8	3.9	42.7		57.7
B1.3.3	Fabrication	-	0.0	0.0	0.0	30%	0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	186.3	11.4	197.7		220.6
		Platform Injector 1-4 + MW	85.0	5.7	90.7		101.1
		Platform Injector 5-8 + MW2	101.4	5.7	107.1		119.5
B1.4	**Other**		1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**704.6**	**59.4**	**764.0**	**-**	**977.2**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	106.0	5.6	111.6		145.1
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	214.2	19.5	233.6		303.7
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	101.1	6.0	107.1		123.3
C1.3.1	**Well Sidetracks and Workovers**	Local Platform Sidetrack 1	25.3	1.5	26.8	30%	30.8
		Local Platform Sidetrack 2	25.3	1.5	26.8		30.8
		Local Platform Sidetrack 3	25.3	1.5	26.8		30.8
		Local Platform Sidetrack 4	25.3	1.5	26.8		30.8
C1.4	**Other**		283.3	28.3	311.6	-	405.1
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	98.8	9.9	108.6		141.2
C1.4.2	Financial Securities		184.5	18.5	202.95	30%	263.8
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**200.9**	**16.2**	**217.1**	**-**	**278.5**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	27.9	2.8	30.7		39.9
D1.2	**Decommissioning - Facilities**	Que$tor	36.9	3.7	40.6	30%	52.8
D1.3	**Decommissioning - Wells**		30.4	2.7	33.1		39.3
D1.4	**Other**		105.6	7.0	112.7	-	146.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	70.4	7.0	77.5	30%	100.7
D1.4.2	Handover	additional 10 years of coverage	35.2	0.0	35.2		45.8

FIELD LIFE (YEARS)	40
CO2 STORED (MT)	170

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC

LEVEL 1 COST ESTIMATE SUMMARY



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	723.4	TRANSPORTATION	279.0
		FACILITIES	97.3
		WELLS	284.0
		OTHER	63.0
OPEX [C]	977.2	TRANSPORTATION	145.1
		FACILITIES	303.7
		WELLS	123.3
		OTHER	405.1
ABEX [D]	278.5	TRANSPORTATION	39.9
		FACILITIES	52.8
		WELLS	39.3
		OTHER	146.5
TOTAL	1979.1	-	1979.1

LEVEL 1 COST ESTIMATE SUMMARY

Category	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)	53.6	6.0	59.6	72.8
B. Post-Final Investment Decision (Post-FID)	495.6	31.1	526.7	650.5
C. Total Operating Expenditure (OPEX)	704.6	59.4	764.0	977.2
D. Abandonment (ABEX)	200.9	16.2	217.1	278.5
TOTAL COST (CAPEX, OPEX, ABEX)			1567.5	**1979.1**
COST CO2 INJECTED (£ PER TONNE)			£9.22	**£11.64**

PROJECT	Strategic UK Storage Appraisal Project	
TITLE	SITE 2: FORTIES 5 - SOUTH SITE	**TRANSPORTATION: PROCUREMENT & FABRICATION**
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	216	
Route Length Factor	1.05	
Pipeline Crossings	7	
Tee Structures	2	
Outer Diameter (mm)	508	
Wall Thickness (mm)	20	
Anode Spacing (m)	500	

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£720,000**
A1.1.1	Pre-FEED	Lump Sum	£200,000	LS	1.00	£200,000	£90,000	*Company Time Writing, Contractor Surveillance*	£290,000
A1.1.2	FEED	Lump Sum	£400,000	LS	1.00	£250,000	£180,000	*Company Time Writing, Contractor Surveillance*	£430,000
B. Post FID									
B1.1	**Transportation - Post FID**								**£133,663,661**
B1.1.1	Detailed Design	Lump Sum	£1,000,000	LS	1.00	£1,000,000	£200,000	*Company Time Writing, IVB, SIT, Insurance etc*	£1,200,000
B1.1.2	Procurement		-	-	-	-	-		**£108,733,661**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	227	£453,600	£28,000	*Documentation etc*	£481,600
B1.1.2.3	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 609.6mm, WT 22.2mm*	£1,500	Te	54,590	£81,885,000	£4,913,100	*Logistics/Freight @ 6%*	£86,798,100
B1.1.2.4	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£42	m	226,800	£9,525,600	£571,536		£10,097,136
B1.1.2.5	*Procurement - Coating (Trunk)*	*Concrete Coating*	£45	m	226,800	£10,206,000	£612,360		£10,818,360
B1.1.2.6	*Procurement - Anodes (Trunk)*	*CP Protection*	£80	Each	454	£36,288	£2,177		£38,465
B1.1.3	Fabrication		-	-	-	-	-		**£23,730,000**
B1.1.3.1	SSIV	Subsea Isolation Valve Structure	£1,500,000	LS	1	£1,500,000	£100,000	*Contractor Surveillance*	£1,600,000
B1.1.3.2	*Spoolbase Fabrication*	*Coating Only (S Lay)*	£50	m	226,800	£11,340,000	£50,000	*Contractor Surveillance*	£11,390,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	7	£700,000	£20,000	*Contractor Surveillance*	£720,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	2	£10,000,000	£20,000	*Contractor Surveillance*	£10,020,000

Total (Excluding Contingency)		**£134,383,661**
Pre-FID Contingency (%)	**30%**	**£216,000**
Post-FID Contingency (%)	**30%**	**£40,099,098**
Total (Including Contingency)		**£174,698,760**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: CONSTRUCTION AND COMMISSIONING**
TITLE	SITE 2: FORTIES 5 - SOUTH SITE	
CLIENT	ETI	
REVISION	A1	
DATE	20/10/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	216	
Route Length Factor	1.05	
Pipeline Crossings	7	
Outer Diameter (mm)	508	
Wall Thickness (mm)	20	
Anode Spacing (m)	500	
Landfall Required?	YES	-

Activity	**Vessel**	**Dayrate (£)**	**Working Rate (m/hr)**
Pipeline Route Survey	Survey Vessel	£100,000	750
Pipelay (Reel)	Reel Lay Vessel	£150,000	500
Pipelay (S-Lay)	S-Lay Vessel (14000Te)	£350,000	100
Trenching and Backfill	Ploughing Vessel	£100,000	400
Crossing Installation	Survey Vessel	£100,000	-
Spoolpiece Tie-ins	DSV	£150,000	-
Commissioning	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-

Landfall Cost	£25,000,000

No.	**Activity**	**Breakdown**	**Vessel**	**Day Rate (£)**	**Days**	**Sub-Total (£)**	**Total Cost (£)**
B. Post FID							
B1.1	**Transportation - Post FID**						
B1.1.4	**Construction and Commissioning**						
B1.1.4.1	Pipeline Route Survey	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,700,000
		Infield Operations			13	£1,300,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000	5	£1,750,000	£35,700,000
		Infield Operations			95	£33,250,000	
		Demobilisation			2	£700,000	
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000	2	£200,000	£2,500,000
		Infield Operations - 3 day per Crossing			21	£2,100,000	
		Demobilisation			2	£200,000	
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£300,000	£2,100,000
		Infield Operations			10	£1,500,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	2	£300,000	£1,050,000
		Infield Operations -SSIV and TeeS			3	£450,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Pipelay (Carrier)	Mobilisation	Pipe Carrier (1600Te)	£50,000	2	£100,000	£5,400,000
		Roundtrip Operations - 4 days per Trip			104	£5,200,000	
		Demobilisation			2	£100,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£5,010,000	£5,010,000
B1.1.4.9	Landfall		-	Lump Sum	-	£25,000,000	£25,000,000
					Total (Excluding Contingency)		**£80,110,000**
					Contingency	**30%**	**£24,033,000**
					Total (Including Contingency)		**£104,143,000**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 2: FORTIES 5 - SOUTH SITE
CLIENT	ETI
REVISION	A1
DATE	20/10/2016

Facilities:
PROCUREMENT & FABRICATION

Pale Blue Dot.

COSTAIN

AXIS WELL TECHNOLOGY
FROM CONCEPT TO COMPLETION

COSTS EXTRACTED FROM QUE$TOR

Exchange Rate (£:$)	1.50

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.2	**Facilities - Pre FID**								**£6,525,000**
A1.2.1	Pre-FEED	4 Legged Jacket, Topsides	£1,500,000	LS	1	£1,500,000	£675,000	*Company Time Writing, Contractor Surveillance*	£2,175,000
A1.2.2	FEED	4 Legged Jacket, Topsides	£3,000,000	LS	1	£3,000,000	£1,350,000	*Company Time Writing, Contractor Surveillance*	£4,350,000
B. Post FID									
B1.2	**Facilities - Post FID**								**£68,358,801**
B1.2.1	Detailed Design	4 Legged Jacket, Topsides	£10,000,000	LS	1	£10,000,000	£3,000,000	*Company Time Writing, IVB, SIT etc*	**£13,000,000**
B1.2.2	Procurement		-	-	-		-	-	**£17,925,265**
	Jacket	4 Legged Jacket	-	-	-		-	-	***£8,903,613***
B1.2.2.1.1	Insurance and Certification		-	-	-		£1,940,000	*Insurance and Certification*	£1,940,000
B1.2.2.1.2	*Jacket Steel*		£1,333	Te	2,700	£3,600,000	£216,000		£3,816,000
B1.2.2.1.3	*Piles*		£1,301	Te	1,850	£2,406,233	£144,374	*Logistics/Freight @ 6%*	£2,550,607
B1.2.2.1.4	*Anodes*		£3,685	Te	110	£405,387	£24,323		£429,710
B1.2.2.1.5	*Installation Aids*		£1,127	Te	140	£157,827	£9,470		£167,296
	Topsides		-	-	-		-	-	***£9,021,652***
B1.2.2.2.1	Insurance and Certification		-	-	-		£940,000	*Insurance and Certification*	£940,000
B1.2.2.2.2	*Primary Steel*		£1,087	Te	170	£184,733	£11,084		£195,817.33
B1.2.2.2.3	*Secondary Steel*		£900	Te	100	£90,000	£5,400		£95,400.00
B1.2.2.2.4	*Piping*		£10,733	Te	30	£322,000	£19,320		£341,320.00
B1.2.2.2.5	*Electrical*		£19,200	Te	15	£288,000	£17,280		£305,280.00
B1.2.2.2.6	*Instrumentation*		£36,333	Te	15	£545,000	£32,700		£577,700.00
B1.2.2.2.7	*Miscellaneous*		£8,800	Te	20	£176,000	£10,560		£186,560.00
B1.2.2.2.8	*Manifolding*		£14,733	Te	20	£294,667	£17,680		£312,346.67
B1.2.2.2.9	*Control and Communications*	*Sat Comms*	£460,733	Te	3	£1,382,200	£82,932		£1,465,132.00
B1.2.2.2.10	*General Utilities*	*Drainage, Diesal Storage etc*	£50,000	Te	4	£200,000	£12,000	*Logistics/Freight @ 6%*	£212,000.00
B1.2.2.2.11	*Vent Stack*	*Low Volume (venting done at beach)*	£6,933	Te	35	£242,667	£14,560		£257,226.67
B1.2.2.2.12	*Diesel Generators*	*Power Generation*	£52,067	Te	15	£781,000	£46,860		£827,860.00
B1.2.2.2.13	*Power Distribution*		£36,067	Te	5	£180,333	£10,820		£191,153.33
B1.2.2.2.14	*Emergency Power*		£34,733	Te	2	£69,467	£4,168		£73,634.67
B1.2.2.2.15	*Quarters and Helideck*	*50 Te Helideck plus TR*	£23,333	Te	70	£1,633,333	£98,000		£1,731,333.33
B1.2.2.2.16	*Crane*	*Mechanical Handling*	£19,267	Te	30	£578,000	£34,680		£612,680.00
B1.2.2.2.17	*Lifeboats*	*Freefall Lifeboats*	£24,400	Te	7	£170,800	£10,248		£181,048.00
B1.2.2.2.18	*Chemical Injection*	*Chemicals, Pumps, Storage*	£46,600	Te	10	£466,000	£27,960		£493,960.00
B1.2.2.2.19	*PLR*	*Pig Reciever*	£10,000	Te	2	£20,000	£1,200		£21,200.00
B1.2.3	Fabrication		-	-			-		**£15,010,978**
	Jacket		-	-			-		***£11,965,421***
B1.2.3.1	*Jacket Steel*		£3,245	m	2,700	£8,760,600	£525,636		£9,286,236
B1.2.3.2	*Piles*		£1,022	m	1,850	£1,890,700	£113,442	*Logistics/Freight @ 6%*	£2,004,142
B1.2.3.3	*Anodes*		£755	Each	110	£83,087	£4,985		£88,072
B1.2.3.4	*Installation Aids*		£3,955		140	£553,747	£33,225		£586,971
	Topsides		-		-		-	-	***£3,045,557***
B1.2.3.2.1	*Primary Steel*		£5,467	Te	170	£929,333	£55,760		£985,093
B1.2.3.2.2	*Secondary Steel*		£7,200	Te	100	£720,000	£43,200		£763,200
B1.2.3.2.3	*Equipment*		£1,513	Te	75	£113,500	£6,810		£120,310
B1.2.3.2.4	*Piping*		£14,867	Te	30	£446,000	£26,760	*Logistics/Freight @ 6%*	£472,760
B1.2.3.2.5	*Electrical*		£26,467	Te	15	£397,000	£23,820		£420,820
B1.2.3.2.6	*PLR*	*Pig Reciever*	£25,000	Te	2	£50,000	£3,000		£53,000
B1.2.3.2.7	*Miscellaneous*		£10,867	Te	20	£217,333	£13,040		£230,373
B1.2.4	Construction and Commissioning		-	-	-		-	-	**£22,422,557**
B1.2.4.1	Installation Spread	Jacket Installation	£596,206	Days	28	£16,693,768	£0	-	£16,693,768
B1.2.4.2	Installation Spread	Topsides Installation	£135,533	Days	7	£948,733	£0	-	£948,733
B1.2.4.3	*Tug Transport - Jacket*	*Mobilisation*	£57,236	Days	4	£228,944	£0	-	£228,944
		Infield Operations	£57,236	Days	16	£915,776	£0	-	£915,776
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.4	*Barge Transport - Jacket*	*Mobilisation*	£8,672	Days	4	£34,688	£0	-	£34,688
		Infield Operations	£8,672	Days	56	£485,632	£0	-	£485,632
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.5	*Tug Transport - Topsides*	*Mobilisation*	£57,236	Days	4	£228,944	£0	-	£228,944
		Infield Operations	£57,236	Days	30	£1,717,080	£0	-	£1,717,080
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.6	*Barge Transport - Topsides*	*Mobilisation*	£8,672	Days	4	£34,688	£0	-	£34,688
		Infield Operations	£8,672	Days	70	£607,040	£0	-	£607,040
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688

Total (Excluding Contingency)		**£74,883,801**
Pre-FID Contingency (%)	**30%**	**£1,957,500**
Post-FID Contingency (%)	**30%**	**£20,507,640**
Total (Including Contingency)		**£97,348,941**

PROJECT	Strategic UK Storage Appraisal Project	**WELLS: COST SUMMARY**
TITLE	SITE 2: FORTIES 5 - NORTH SITE	
CLIENT	ETI	
REVISION	DRAFT	
DATE	42382	

Well Cost Summary (including 30% Contingency)		
Well Name	**Days**	**Well Cost (£,000)**
Year -2		
Appraisal Well	97.3	34747.5
Year 0		
Platform Injector 1	68.3	27884.8
Platform Injector 2	61.8	25460.3
Platform Injector 3	61.8	25460.3
Platform Injector 4	61.8	25460.3
Monitoring Well 1 / Spare Injector	66.8	26865.3
Year 5		
Local Platform Sidetrack 1	85.2	30837.45
Year 15		
Local Platform Sidetrack 2	85.2	30837.45
Year 20		
Sidetrack for new Platform Injector 5	81.3	30263.75
Sidetrack for new Platform Injector 6	74.8	27839.25
Sidetrack for new Platform Injector 7	74.8	27839.25
Sidetrack for new Platform Injector 8	74.8	27839.25
Sidetrack for Monitoring Well 2 / Spare Injecto	79.8	29504.25
Year 25		
Local Platform Sidetrack 3	85.2	30837.45
Year 35		
Local Platform Sidetrack 4	85.2	30837.45
Year 40		
Abandonment Platform Injector 5	28.6	9263.8
Abandonment Platform Injector 6	22.1	6839.3
Abandonment Platform Injector 7	22.1	6839.3
Abandonment Platform Injector 8	22.1	6839.3
Abandonment Monitoring Well 2	28.6	8678.8
TOTAL	1266.9	470974.3

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary	
Drilling Campaign	**Overhead (£MM)**
Appraisal Well	**0.90**
Platform Injector 1-4 + MW	**5.70**
Platform Injector 5-8 + MW2	**5.70**
Abandonment	**2.70**

OPEX Overhead Cost Summary	
OPEX Campaign	**Overhead (£MM)**
Local Platform Sidetrack 1	**1.50**
Local Platform Sidetrack 2	**1.50**
Local Platform Sidetrack 3	**1.50**
Local Platform Sidetrack 4	**1.50**

Wells Cost Estimate - Primary Cost Summary						
Activity	**Drilling Costs**			**Procurement Costs (£,000)**		**Total Cost (£,000)**
	Phase Rig Cost (£,000)	**Phase Spread Cost (£,000)**	**Contingency (£,000)**	**Procurement (£,000)**	**Contingency (£,000)**	
Appraisal Well - CAPEX Breakdown						
Appraisal Well	10,418	16,243	3,278	3,700	1,110	34,748
Development Wells - CAPEX Breakdown						
Platform Injector 1	6,983	10,988	2,245	5,900	1,770	27,885
Platform Injector 2	6,318	10,013	2,045	5,450	1,635	25,460
Platform Injector 3	6,318	10,013	2,045	5,450	1,635	25,460
Platform Injector 4	6,318	10,013	2,045	5,450	1,635	25,460
Monitoring Well 1 / Spare Injector	6,983	11,013	2,045	5,250	1,575	26,865
Sidetrack for new Platform Injector 5	8,313	12,938	2,644	4,900	1,470	30,264
Sidetrack for new Platform Injector 6	7,648	11,963	2,444	4,450	1,335	27,839
Sidetrack for new Platform Injector 7	7,648	11,963	2,444	4,450	1,335	27,839
Sidetrack for new Platform Injector 8	7,648	11,963	2,444	4,450	1,335	27,839
Sidetrack for Monitoring Well 2 / Spare Injector	8,313	12,963	2,444	4,450	1,335	29,504
Wells - OPEX Breakdown						
Local Platform Sidetrack 1	8,712	13,773	2,763	4,300	1,290	30,837
Local Platform Sidetrack 2	8,712	13,773	2,763	4,300	1,290	30,837
Local Platform Sidetrack 3	8,712	13,773	2,763	4,300	1,290	30,837
Local Platform Sidetrack 4	8,712	13,773	2,763	4,300	1,290	30,837
Wells - ABEX Breakdown						
Abandonment Platform Injector 5	2,926	4,140	1,028	900	270	9,264
Abandonment Platform Injector 6	2261	3165	828.3	450	135	6839.3
Abandonment Platform Injector 7	2261	3165	828.3	450	135	6839.3
Abandonment Platform Injector 8	2261	3165	828.3	450	135	6839.3
Abandonment Monitoring Well 2	2926	4140	1027.8	450	135	8678.8

	CAPEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
						%	**£MM**	
A1.4.2	Appraisal Well (inc Procurement)	29.5	0.90	Well Management Fees, Insurance, Site Survey, Studies etc	30.4	30%	4.4	**34.7**
A1.3	Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.9**
B1.3.1	Detailed Design PM & E	2.0	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	38.8	3.9		42.7	30%	15.1	**57.7**
B1.3.4	Construction and Commissioning (Drilling)	186.3	11.40	Well Management Fees, Insurance, Site Survey, Studies etc.	197.7	30%	22.8	**220.6**
	Total	**258.6**	**16.6**		**275.2**	**-**	**43.6**	**318.8**

OPEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
OPEX	101.1	6.00	Well Management Fees, Insurance, Site Survey, Studies etc.	107.1	30%	16.2	**123.3**

ABEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
ABEX	30.4	2.70	Well Management Fees, Insurance, Site Survey, Studies etc.	33.1	30%	5.4	**39.3**

	Level 1 Cost Estimate Summary - Wells	
	Total CAPEX (£MM)	318.8
C1.3	Total OPEX (£MM)	123.3
D1.3	Total ABEX (£MM)	39.3
	TOTAL (£MM)	**481.4**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 7: BUNTER CLOSURE 36 Minimum Viable Development
CLIENT	ETI
REVISION	A01
DATE	20/10/2016

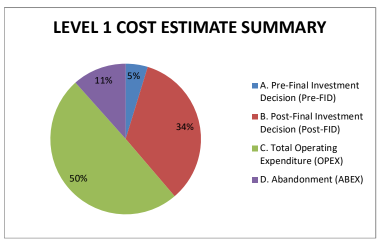
LEVEL 2 COST ESTIMATE

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**35.7**	**4.9**	**40.7**		**51.7**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.5	0.2	0.7		0.8
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	4.5	2.0	6.5		8.5
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	2.0	0.2	2.2		2.9
A1.4	**Other**		28.8	2.5	31.3	30%	39.5
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	4.0	0.4	4.4		5.7
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	21.8	0.9	22.7		28.4
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**268.6**	**18.9**	**287.5**	**-**	**372.6**
B1.1	**Transportation**		117.3	3.1	120.3	-	156.5
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.0	0.2	1.2		1.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	36.4	2.7	39.1	30%	50.9
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	15.4	0.2	15.6		20.3
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	64.4	0.0	64.4		83.8
B1.2	**Facilities**		61.7	7.9	69.6	-	90.5
B1.2.1	Detailed Design		10.0	3.0	13.0		16.9
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	15.1	4.1	19.2	30%	24.9
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	14.2	0.9	15.0		19.5
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	22.4	0.0	22.4		29.1
B1.3	**Wells**		88.6	7.0	95.6	-	123.0
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	2.0	0.2	2.2		2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	25.6	0.0	25.6		33.3
B1.3.3	Fabrication	-	0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	61.0	6.8	67.8	30%	86.9
		Well 1-4	30.5	2.7	33.2		42.6
		Well 5	0.0	0.9	0.9		1.2
		4 Rep. Wells	30.5	2.3	32.8		42.0
		5th Rep. Well	0.0	0.9	0.9		1.2
B1.4	**Other**		1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**386.2**	**35.9**	**422.1**	**-**	**544.3**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	59.8	3.1	62.9		81.8
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	217.8	19.8	237.6		308.9
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	19.8	4.1	23.8		26.5
C1.3.1	**Well Sidetracks and Workovers**	Local Sidetrack 1	19.8	0.9	20.7	30%	25.6
		Local Sidetrack 2	0.0	0.9	0.9		0.3
		Workover1	0.0	0.5	0.5		0.1
		Local Sidetrack 3	0.0	0.9	0.9		0.3
		Local Sidetrack 4	0.0	0.9	0.9		0.3
C1.4	**Other**		88.9	8.9	97.74617775	-	127.1
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	8.0	0.8	8.8		11.4
C1.4.2	Financial Securities		80.9	8.1	88.94617775	30%	115.6
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**85.4**	**12.2**	**97.5**	**-**	**126.8**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	15.7	1.6	17.3		22.5
D1.2	**Decommissioning - Facilities**	Que$tor	40.9	4.1	44.9	30%	58.4
D1.3	**Decommissioning - Wells**		12.3	5.4	17.7		22.9
D1.4	**Other**		16.5	1.1	17.64571429	-	22.9
D1.4.1	Post Closure Monitoring	includes data management and interpretation	11.0	1.1	12.13142857	30%	15.8
D1.4.2	Handover	additional 10 years of coverage	5.5	0.0	5.514285714		7.2

FIELD LIFE (YEARS)	40
CO2 STORED (MT)	80

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY			
COST	**TOTAL COST (£ MM)**	**CATEGORY**	**COST (£ MM)**
CAPEX [A + B]	424.3	TRANSPORTATION	157.3
		FACILITIES	99.0
		WELLS	125.9
		OTHER	42.1
OPEX [C]	544.3	TRANSPORTATION	81.8
		FACILITIES	308.9
		WELLS	26.5
		OTHER	127.1
ABEX [D]	126.8	TRANSPORTATION	22.5
		FACILITIES	58.4
		WELLS	22.9
		OTHER	22.9
TOTAL	1095.5	-	1095.5

LEVEL 1 COST ESTIMATE SUMMARY				
Category	**Primary Cost (£ MM)**	**Overheads (£ MM)**	**Total Cost excluding Contingency (£ MM)**	**Total Cost inc. Contingency (£ MM)**
A. Pre-Final Investment Decision (Pre-FID)	35.7	4.9	40.7	51.7
B. Post-Final Investment Decision (Post-FID)	268.6	18.9	287.5	372.6
C. Total Operating Expenditure (OPEX)	386.2	35.9	422.1	544.3
D. Abandonment (ABEX)	85.4	12.2	97.5	126.8
TOTAL COST (CAPEX, OPEX, ABEX)			847.9	**1095.5**
COST CO2 INJECTED (£ PER TONNE)			£10.60	**£13.69**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	3UNTER CLOSURE 36 Minimum Viable Dev	
CLIENT	ETI	
REVISION	A01	
DATE	20/10/2016	

Pale Blue Dot.

COSTAIN

AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	160	
Route Length Factor	1.05	
Pipeline Crossings	5	
Tee Structures	1	
Outer Diameter (mm)	304.8	
Wall Thickness (mm)	15.24	
Anode Spacing (m)	500	

No.	**Item**	**Description**	**Unit Cost (£)**	**Unit**	**Qty**	**Total (£MM)**	**Overhead (£)**	**Description (Overheads)**	**Total Cost (£)**
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£652,500**
A1.1.1	Pre-FEED	Lump Sum	£200,000	LS	1.00	£200,000	£90,000	*Company Time Writing, Contractor Surveillance*	£290,000
A1.1.2	FEED	Lump Sum	£250,000	LS	1.00	£250,000	£112,500	*Company Time Writing, Contractor Surveillance*	£362,500
B. Post FID									
B1.1	**Transportation - Post FID**								**£55,914,488**
B1.1.1	Detailed Design	Lump Sum	£1,000,000	LS	1.00	£1,000,000	£200,000	*Company Time Writing, IVB, SIT, Insurance etc*	£1,200,000
B1.1.2	Procurement		-	-	-	-	-		**£39,124,488**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	168	£336,000	£28,000	*Documentation etc*	£364,000
B1.1.2.3	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 457.2mm, WT 21.4mm*	£1,500	Te	18,284	£27,426,000	£1,645,560	*Logistics/Freight @ 6%*	£29,071,560
B1.1.2.4	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£20	m	168,000	£3,360,000	£201,600		£3,561,600
B1.1.2.5	*Procurement - Coating (Trunk)*	*Concrete Coating*	£30	m	176,400	£5,292,000	£317,520		£5,609,520
B1.1.2.6	*Procurement - Anodes (Trunk)*	*CP Protection*	£50	Each	336	£16,800	£1,008		£17,808
B1.1.3	Fabrication		-	-	-	-	-		**£15,590,000**
B1.1.3.1	SSIV	Subsea Isolation Valve Structure	£1,500,000	LS	1	£1,500,000	£100,000	*Contractor Surveillance*	£1,600,000
B1.1.3.2	*Spoolbase Fabrication*	*Coating Only (S Lay)*	£50	m	168,000	£8,400,000	£50,000	*Contractor Surveillance*	£8,450,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	5	£500,000	£20,000	*Contractor Surveillance*	£520,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	1	£5,000,000	£20,000	*Contractor Surveillance*	£5,020,000

Total (Excluding Contingency)		**£56,566,988**
Pre-FID Contingency (%)	**30%**	**£195,750**
Post-FID Contingency (%)	**30%**	**£16,774,346**
Total (Including Contingency)		**£73,537,084**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: CONSTRUCTION AND COMMISSIONING**
TITLE	UNTER CLOSURE 36 Minimum Viable De	
CLIENT	ETI	
REVISION	A01	
DATE	20/10/2016	

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	160	
Route Length Factor	1.05	
Pipeline Crossings	5	
Outer Diameter (mm)	304.8	
Wall Thickness (mm)	15.24	
Anode Spacing (m)	500	
Landfall Required?	YES	-

Activity	**Vessel**	**Dayrate (£)**	**Working Rate (m/hr)**
Pipeline Route Survey	Survey Vessel	£100,000	750
Pipelay (Reel)	Reel Lay Vessel	£150,000	500
Pipelay (S-Lay)	S-Lay Vessel (14000Te)	£350,000	100
Trenching and Backfill	Ploughing Vessel	£100,000	400
Crossing Installation	Survey Vessel	£100,000	-
Spoolpiece Tie-ins	DSV	£150,000	-
Commissioning	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-

Landfall Cost	£25,000,000

No.	**Activity**	**Breakdown**	**Vessel**	**Day Rate (£)**	**Days**	**Sub-Total (£)**	**Total Cost (£)**
B. Post FID							
B1.1	**Transportation - Post FID**						
B1.1.4	**Construction and Commissioning**						
B1.1.4.1	Pipeline Route Survey	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,400,000
		Infield Operations			10	£1,000,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000	5	£1,750,000	£26,950,000
		Infield Operations			70	£24,500,000	
		Demobilisation			2	£700,000	
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,900,000
		Infield Operations - 3 day per Crossing			15	£1,500,000	
		Demobilisation			2	£200,000	
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£300,000	£2,100,000
		Infield Operations			10	£1,500,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	2	£300,000	£1,050,000
		Infield Operations -SSIV and Tee			3	£450,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Pipelay (Carrier)	Mobilisation	Pipe Carrier (1600Te)	£50,000	2	£100,000	£800,000
		Roundtrip Operations - 4 days per Trip			12	£600,000	
		Demobilisation			2	£100,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£3,585,000	£3,585,000
B1.1.4.9	Landfall		-	Lump Sum	-	£25,000,000	£25,000,000
					Total (Excluding Contingency)		**£64,435,000**
					Contingency	**30%**	**£19,330,500**
					Total (Including Contingency)		**£83,765,500**

PROJECT	Strategic UK Storage Appraisal Project	Facilities: PROCUREMENT & FABRICATION
TITLE	BUNTER CLOSURE 36 Minimum Viable Dev	
CLIENT	ETI	
REVISION	A01	
DATE	20/10/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

COSTS EXTRACTED FROM QUE$TOR

Exchange Rate (£:$) **1.50**

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.2	**Facilities - Pre FID**								**£6,525,000**
A1.2.1	Pre-FEED	4 Legged Jacket, Topsides	£1,500,000	LS	1	£1,500,000	£675,000	*Company Time Writing, Contractor Surveillance*	£2,175,000
A1.2.2	FEED	4 Legged Jacket, Topsides	£3,000,000	LS	1	£3,000,000	£1,350,000	*Company Time Writing, Contractor Surveillance*	£4,350,000
B. Post FID									
B1.2	**Facilities - Post FID**								**£69,643,560**
B1.2.1	Detailed Design	4 Legged Jacket, Topsides	£10,000,000	LS	1	£10,000,000	£3,000,000	*Company Time Writing, IVB, SIT etc*	**£13,000,000**
B1.2.2	Procurement		-	-	-		-	-	**£19,189,354**
	Jacket	4 Legged Jacket	-	-	-		-	-	***£7,815,484***
B1.2.2.1.1	Insurance and Certification		-	-	-		£1,872,000	*Insurance and Certification*	£1,872,000
B1.2.2.1.2	*Jacket Steel*		£1,333	Te	2,650	£3,533,333	£212,000		£3,745,333
B1.2.2.1.3	*Piles*		£1,301	Te	1,000	£1,300,667	£78,040	*Logistics/Freight @ 6%*	£1,378,707
B1.2.2.1.4	*Anodes*		£3,685	Te	170	£626,507	£37,590		£664,097
B1.2.2.1.5	*Installation Aids*		£1,127	Te	130	£146,553	£8,793		£155,347
	Topsides		-	-	-		-	-	***£11,373,871***
B1.2.2.2.1	Insurance and Certification		-	-	-		£1,272,000	*Insurance and Certification*	£1,272,000
B1.2.2.2.2	*Primary Steel*		£1,087	Te	230	£249,933	£14,996		£264,929
B1.2.2.2.3	*Secondary Steel*		£900	Te	150	£135,000	£8,100		£143,100
B1.2.2.2.4	*Piping*		£10,733	Te	40	£429,333	£25,760		£455,093
B1.2.2.2.5	*Electrical*		£19,200	Te	20	£384,000	£23,040		£407,040
B1.2.2.2.6	*Instrumentation*		£36,333	Te	20	£726,667	£43,600		£770,267
B1.2.2.2.7	*Miscellaneous*		£8,800	Te	20	£176,000	£10,560		£186,560
B1.2.2.2.8	*Manifolding*		£14,733	Te	50	£736,667	£44,200		£780,867
B1.2.2.2.9	*Control and Communications*	*Sat Comms*	£460,733	Te	5	£2,303,667	£138,220		£2,441,887
B1.2.2.2.10	*General Utilities*	*Drainage, Diesal Storage etc*	£50,000	Te	3	£150,000	£9,000	*Logistics/Freight @ 6%*	£159,000
B1.2.2.2.11	*Vent Stack*	*Low Volume (venting done at beach)*	£6,933	Te	34	£235,733	£14,144		£249,877
B1.2.2.2.12	*Diesel Generators*	*Power Generation*	£52,067	Te	17	£885,133	£53,108		£938,241
B1.2.2.2.13	*Power Distribution*		£36,067	Te	5	£180,333	£10,820		£191,153
B1.2.2.2.14	*Emergency Power*		£34,733	Te	2	£69,467	£4,168		£73,635
B1.2.2.2.15	*Quarters and Helideck*	*50 Te Helideck plus TR*	£23,333	Te	70	£1,633,333	£98,000		£1,731,333
B1.2.2.2.16	*Crane*	*Mechanical Handling*	£19,267	Te	30	£578,000	£34,680		£612,680
B1.2.2.2.17	*Lifeboats*	*Freefall Lifeboats*	£24,400	Te	7	£170,800	£10,248		£181,048
B1.2.2.2.18	*Chemical Injection*	*Chemicals, Pumps, Storage*	£46,600	Te	10	£466,000	£27,960		£493,960
B1.2.2.2.19	*PLR*	*Pig Reciever*	£10,000	Te	2	£20,000	£1,200		£21,200
B1.2.3	Fabrication		-	-			-		**£15,031,648**
	Jacket		-	-			-		***£10,878,745***
B1.2.3.1	*Jacket Steel*		£3,245	m	2,650	£8,598,367	£515,902		£9,114,269
B1.2.3.2	*Piles*		£1,022	m	1,000	£1,022,000	£61,320	*Logistics/Freight @ 6%*	£1,083,320
B1.2.3.3	*Anodes*		£755	Each	170	£128,407	£7,704		£136,111
B1.2.3.4	*Installation Aids*		£3,955		130	£514,193	£30,852		£545,045
	Topsides		-		-		-	-	***£4,152,903***
B1.2.3.2.1	*Primary Steel*		£5,467	Te	230	£1,257,333	£75,440		£1,332,773
B1.2.3.2.2	*Secondary Steel*		£7,200	Te	150	£1,080,000	£64,800		£1,144,800
B1.2.3.2.3	*Equipment*		£1,513	Te	125	£189,167	£11,350		£200,517
B1.2.3.2.4	*Piping*		£14,867	Te	40	£594,667	£35,680	*Logistics/Freight @ 6%*	£630,347
B1.2.3.2.5	*Electrical*		£26,467	Te	20	£529,333	£31,760		£561,093
B1.2.3.2.6	*PLR*	*Pig Reciever*	£25,000	Te	2	£50,000	£3,000		£53,000
B1.2.3.2.7	*Miscellaneous*		£10,867	Te	20	£217,333	£13,040		£230,373
B1.2.4	Construction and Commissioning		-	-	-		-	-	**£22,422,557**
B1.2.4.1	Installation Spread	Jacket Installation	£596,206	Days	28	£16,693,768	£0	-	£16,693,768
B1.2.4.2	Installation Spread	Topsides Installation	£135,533	Days	7	£948,733	£0	-	£948,733
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.3	*Tug Transport - Jacket*	*Infield Operations*	£57,236	Days	16	£915,776	£0	-	£915,776
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.4	*Barge Transport - Jacket*	*Infield Operations*	£8,672	Days	56	£485,632	£0	-	£485,632
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.5	*Tug Transport - Topsides*	*Infield Operations*	£57,236	Days	30	£1,717,080	£0	-	£1,717,080
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.6	*Barge Transport - Topsides*	*Infield Operations*	£8,672	Days	70	£607,040	£0	-	£607,040
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
				Total (Excluding Contingency)					**£76,168,560**
				Pre-FID Contingency (%)				**30%**	**£1,957,500**
				Post-FID Contingency (%)				**30%**	**£20,893,067.88**
				Total (Including Contingency)					**£99,019,127**

PROJECT	Strategic UK Storage Appraisal Project	WELLS: COST SUMMARY
TITLE	UNTER CLOSURE 36 Minimum Viable De	
CLIENT	ETI	
REVISION	A01	
DATE	42663	

Well Cost Summary (including 30% Contingency)

Well Name	Days	Well Cost (£,000)
Year -2		
Appraisal Well	80.6	26687.5
Year 0		
Slant Injector 1	77.4	26637.5
Slant Injector 2	70.9	24562.5
Slant Injector 3		
Slant Injector 4		
Monitoring Well - Appraisal Tieback	0.0	0.0
Year 2		
Slant Injector 5		
Year 5		
Local Sidetrack 1	80.6	25300
Year 15		
Local Sidetrack 2		
Year 20		
Slant Injector 6	77.4	26637.5
Slant Injector 7	70.9	24562.5
Slant Injector 8		
Slant Injector 9		
Workover 1		
Year 22		
Slant Injector 10		
Year 25		
Local Sidetrack 3		
Year 35		
Local Sidetrack 4		
Year 40		
Abandonment Slant Injector 1	23.4	6750
Abandonment Slant Injector 2	16.9	4675
Abandonment Slant Injector 3		
Abandonment Slant Injector 4		
Abandonment Slant Injector 5		
Abandonment Slant Injector 6		
Abandonment Slant Injector 7		
Abandonment Slant Injector 8		
Abandonment Slant Injector 9		
Abandonment Slant Injector 10		
Abandonment Monitoring Well	23.4	6300
TOTAL	521.3	172112.5

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary

Drilling Campaign	Overhead (£MM)
Well 1-4	2.70
Well 5	0.90
4 Rep. Wells	2.25
5th Rep. Well	0.90

OPEX Overhead Cost Summary

OPEX Campaign	Overhead (£MM)
Local Sidetrack 1	0.90
Local Sidetrack 2	0.90
Workover1	0.45
Local Sidetrack 3	0.90
Local Sidetrack 4	0.90

Wells Cost Estimate - Primary Cost Summary

Activity	Drilling Costs: Phase Rig Cost (£,000)	Drilling Costs: Phase Spread Cost (£,000)	Drilling Costs: Contingency (£,000)	Procurement Costs (£,000): Procurement (£,000)	Procurement Costs (£,000): Contingency (£,000)	Total Cost (£,000)
Appraisal Well - CAPEX Breakdown						
Appraisal Well	6450	10625	4012.5	4700	1410	27197.5
Development Wells - CAPEX Breakdown						
Slant Injector 1	5950	9925	4462.5	6400	1920	28657.5
Slant Injector 2	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 3						
Slant Injector 4						
Monitoring Well (Appraisal)	0	0	0	0	0	0
Slant Injector 5						
Slant Injector 6	5950	9925	4462.5	6400	1920	28657.5
Slant Injector 7	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 8						
Slant Injector 9						
Slant Injector 10						
Wells - OPEX Breakdown						
Local Sidetrack 1	6200	10550	4650	3000	900	25300
Local Sidetrack 2						
Workover 1						
Local Sidetrack 3						
Local Sidetrack 4						
Wells - ABEX Breakdown						
Abandonment Slant Injector 1	1530	2970	1350	0	0	5850
Abandonment Slant Injector 2	1105	2145	975	0	0	4225
Abandonment Slant Injector 3						
Abandonment Slant Injector 4						
Abandonment Slant Injector 5						
Abandonment Slant Injector 6						
Abandonment Slant Injector 7						
Abandonment Slant Injector 8						
Abandonment Slant Injector 9						
Abandonment Slant Injector 10						
Abandonment Monitoring Well	1530	2970	1350	0	0	5850

	CAPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
A1.4.2	Appraisal Well (inc Procurement)	21.8	0.9	Well Management Fees, Insurance, Site Survey, Studies etc	22.7	30%	5.7	**28.4**
A1.3	Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.86**
B1.3.1	Detailed Design PM & E	2.0	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	25.6	0		25.6	30%	7.7	**33.3**
B1.3.4	Construction and Commissioning (Drilling)	61.0	6.75	Well Management Fees, Insurance, Site Survey, Studies etc.	67.8	30%	19.1	**86.9**
	Total	**112.4**	0		**120.4**	-	**33.8**	**154.2**

OPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
OPEX	19.8	4.05	Well Management Fees, Insurance, Site Survey, Studies etc.	23.8	30%	5.9	**29.7**

ABEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
ABEX	12.3	5.4	Well Management Fees, Insurance, Site Survey, Studies etc.	17.7	30%	5.3	**22.9**

Level 1 Cost Estimate Summary - Wells

	Total CAPEX (£MM)	154.24
C1.3	Total OPEX (£MM)	29.7
D1.3	Total ABEX (£MM)	22.9
	TOTAL (£MM)	**206.9**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 7: BUNTER CLOSURE 36 Minimum Viable Development
CLIENT	ETI
REVISION	A01
DATE	20/10/2016

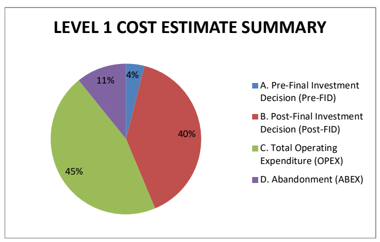
LEVEL 2 COST ESTIMATE

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excl. Contingency (£ MM)	Contingency (%)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)		including Pre-FEED / FEED Design and Engineering	**35.7**	**4.9**	**40.7**		**51.7**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.5	0.2	0.7		0.8
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	4.5	2.0	6.5		8.5
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	2.0	0.2	2.2		2.9
A1.4	**Other**		28.8	2.5	31.3	30%	39.5
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	4.0	0.4	4.4		5.7
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	21.8	0.9	22.7		28.4
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	2.0	0.2	2.2		2.9
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0		2.6
B. Post-Final Investment Decision (Post-FID)			**376.0**	**20.2**	**396.2**	**-**	**512.7**
B1.1	**Transportation**		140.6	4.4	144.9	-	188.4
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.0	0.2	1.2		1.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	57.8	4.0	61.7	30%	80.3
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	15.4	0.2	15.6		20.3
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	66.4	0.0	66.4		86.3
B1.2	**Facilities**		61.7	7.9	69.6	-	90.5
B1.2.1	Detailed Design		10.0	3.0	13.0		16.9
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	15.1	4.1	19.2	30%	24.9
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	14.2	0.9	15.0		19.5
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	22.4	0.0	22.4		29.1
B1.3	**Wells**		172.7	7.0	179.7	-	231.1
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	2.0	0.2	2.2		2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	51.2	0.0	51.2		66.6
B1.3.3	Fabrication	-	0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	119.5	6.8	126.3	30%	161.7
		Well 1-4	59.8	2.7	62.5		80.0
		Well 5	0.0	0.9	0.9		1.2
		4 Rep. Wells	59.8	2.3	62.0		79.4
		5th Rep. Well	0.0	0.9	0.9		1.2
B1.4	**Other**		1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			**417.9**	**38.5**	**456.4**	**-**	**588.9**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	71.9	3.8	75.7		98.4
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	217.8	19.8	237.6		308.9
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	19.8	4.1	23.8		26.5
C1.3.1	**Well Sidetracks and Workovers**	Local Sidetrack 1	19.8	0.9	20.7	30%	25.6
		Local Sidetrack 2	0.0	0.9	0.9		0.3
		Workover1	0.0	0.5	0.5		0.1
		Local Sidetrack 3	0.0	0.9	0.9		0.3
		Local Sidetrack 4	0.0	0.9	0.9		0.3
C1.4	**Other**		108.4	10.8	119.2419142	-	155.0
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	16.0	1.6	17.6		22.9
C1.4.2	Financial Securities		92.4	9.2	101.6419142	30%	132.1
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**95.1**	**12.5**	**107.6**	**-**	**139.8**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	18.9	1.9	20.8		27.1
D1.2	**Decommissioning - Facilities**	Que$tor	40.9	4.1	44.9	30%	58.4
D1.3	**Decommissioning - Wells**		18.8	5.4	24.2		31.4
D1.4	**Other**		16.5	1.1	17.64571429	-	22.9
D1.4.1	Post Closure Monitoring	includes data management and interpretation	11.0	1.1	12.13142857	30%	15.8
D1.4.2	Handover	additional 10 years of coverage	5.5	0.0	5.514285714		7.2

FIELD LIFE (YEARS)	40
CO2 STORED (MT)	160

DEFINITIONS	
TRANSPORTATION	CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE)
FACILITIES	NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES
WELLS	ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS
OTHER	ANY AND ALL COSTS NOT COVERED WITHIN ABOVE
PRIMARY COST	PRIMARY CONTRACT COSTS
OVERHEAD	ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	564.4	TRANSPORTATION	189.3
		FACILITIES	99.0
		WELLS	234.0
		OTHER	42.1
OPEX [C]	588.9	TRANSPORTATION	98.4
		FACILITIES	308.9
		WELLS	26.5
		OTHER	155.0
ABEX [D]	139.8	TRANSPORTATION	27.1
		FACILITIES	58.4
		WELLS	31.4
		OTHER	22.9
TOTAL	1293.2	-	1293.2

LEVEL 1 COST ESTIMATE SUMMARY

Category	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)	35.7	4.9	40.7	51.7
B. Post-Final Investment Decision (Post-FID)	376.0	20.2	396.2	512.7
C. Total Operating Expenditure (OPEX)	417.9	38.5	456.4	588.9
D. Abandonment (ABEX)	95.1	12.5	107.6	139.8
TOTAL COST (CAPEX, OPEX, ABEX)			1000.8	**1293.2**
COST CO2 INJECTED (£ PER TONNE)			£6.26	**£8.08**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	BUNTER CLOSURE 36 Minimum Viable Dev	
CLIENT	ETI	
REVISION	A01	
DATE	20/10/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	160	
Route Length Factor	1.05	
Pipeline Crossings	5	
Tee Structures	1	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	20.32	
Anode Spacing (m)	500	

No.	**Item**	**Description**	**Unit Cost (£)**	**Unit**	**Qty**	**Total (£MM)**	**Overhead (£)**	**Description (Overheads)**	**Total Cost (£)**
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£652,500**
A1.1.1	Pre-FEED	Lump Sum	£200,000	LS	1.00	£200,000	£90,000	*Company Time Writing, Contractor Surveillance*	£290,000
A1.1.2	FEED	Lump Sum	£250,000	LS	1.00	£250,000	£112,500	*Company Time Writing, Contractor Surveillance*	£362,500
B. Post FID									
B1.1	**Transportation - Post FID**								**£78,524,288**
B1.1.1	Detailed Design	Lump Sum	£1,000,000	LS	1.00	£1,000,000	£200,000	*Company Time Writing, IVB, SIT, Insurance etc*	£1,200,000
B1.1.2	Procurement		-	-	-	-	-		**£61,734,288**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	168	£336,000	£28,000	*Documentation etc*	£364,000
B1.1.2.3	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 457.2mm, WT 21.4mm*	£1,500	Te	32,504	£48,756,000	£2,925,360	*Logistics/Freight @ 6%*	£51,681,360
B1.1.2.4	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£20	m	168,000	£3,360,000	£201,600		£3,561,600
B1.1.2.5	*Procurement - Coating (Trunk)*	*Concrete Coating*	£30	m	176,400	£5,292,000	£317,520		£5,609,520
B1.1.2.6	*Procurement - Anodes (Trunk)*	*CP Protection*	£50	Each	336	£16,800	£1,008		£17,808
B1.1.3	Fabrication		-	-	-	-	-		**£15,590,000**
B1.1.3.1	SSIV	Subsea Isolation Valve Structure	£1,500,000	LS	1	£1,500,000	£100,000	*Contractor Surveillance*	£1,600,000
B1.1.3.2	*Spoolbase Fabrication*	*Coating Only (S Lay)*	£50	m	168,000	£8,400,000	£50,000	*Contractor Surveillance*	£8,450,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	5	£500,000	£20,000	*Contractor Surveillance*	£520,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	1	£5,000,000	£20,000	*Contractor Surveillance*	£5,020,000

Total (Excluding Contingency)		**£79,176,788**
Pre-FID Contingency (%)	**30%**	**£195,750**
Post-FID Contingency (%)	**30%**	**£23,557,286**
Total (Including Contingency)		**£102,929,824**

PROJECT	Strategic UK Storage Appraisal Project	TRANSPORTATION: CONSTRUCTION AND COMMISSIONING
TITLE	UNTER CLOSURE 36 Minimum Viable De	
CLIENT	ETI	
REVISION	A01	
DATE	20/10/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	Trunk Pipeline(s)	Infield Pipeline(s)
Number	1	
Route Length (km)	160	
Route Length Factor	1.05	
Pipeline Crossings	5	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	20.32	
Anode Spacing (m)	500	
Landfall Required?	YES	-

Activity	Vessel	Dayrate (£)	Working Rate (m/hr)
Pipeline Route Survey	Survey Vessel	£100,000	750
Pipelay (Reel)	Reel Lay Vessel	£150,000	500
Pipelay (S-Lay)	S-Lay Vessel (14000Te)	£350,000	100
Trenching and Backfill	Ploughing Vessel	£100,000	400
Crossing Installation	Survey Vessel	£100,000	-
Spoolpiece Tie-ins	DSV	£150,000	-
Commissioning	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-

Landfall Cost	£25,000,000

No.	Activity	Breakdown	Vessel	Day Rate (£)	Days	Sub-Total (£)	Total Cost (£)
B. Post FID							
B1.1	Transportation - Post FID						
B1.1.4	Construction and Commissioning						
B1.1.4.1	Pipeline Route Survey	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,400,000
		Infield Operations			10	£1,000,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000	5	£1,750,000	£26,950,000
		Infield Operations			70	£24,500,000	
		Demobilisation			2	£700,000	
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,900,000
		Infield Operations - 3 day per Crossing			15	£1,500,000	
		Demobilisation			2	£200,000	
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£300,000	£2,100,000
		Infield Operations			10	£1,500,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	2	£300,000	£1,050,000
		Infield Operations -SSIV and Tee			3	£450,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Pipelay (Carrier)	Mobilisation	Pipe Carrier (1600Te)	£50,000	2	£100,000	£2,600,000
		Roundtrip Operations - 4 days per Trip			48	£2,400,000	
		Demobilisation			2	£100,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£3,765,000	£3,765,000
B1.1.4.9	Landfall		-	Lump Sum	-	£25,000,000	£25,000,000
					Total (Excluding Contingency)		£66,415,000
					Contingency	30%	£19,924,500
					Total (Including Contingency)		£86,339,500

PROJECT	Strategic UK Storage Appraisal Project	**Facilities:** **PROCUREMENT & FABRICATION**	Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION
TITLE	BUNTER CLOSURE 36 Minimum Viable Dev		
CLIENT	ETI		
REVISION	A01		
DATE	20/10/2016		

COSTS EXTRACTED FROM QUE$TOR

Exchange Rate (£:$) **1.50**

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.2	**Facilities - Pre FID**								**£6,525,000**
A1.2.1	Pre-FEED	4 Legged Jacket, Topsides	£1,500,000	LS	1	£1,500,000	£675,000	*Company Time Writing, Contractor Surveillance*	£2,175,000
A1.2.2	FEED	4 Legged Jacket, Topsides	£3,000,000	LS	1	£3,000,000	£1,350,000	*Company Time Writing, Contractor Surveillance*	£4,350,000
B. Post FID									
B1.2	**Facilities - Post FID**								**£69,643,560**
B1.2.1	Detailed Design	4 Legged Jacket, Topsides	£10,000,000	LS	1	£10,000,000	£3,000,000	*Company Time Writing, IVB, SIT etc*	**£13,000,000**
B1.2.2	Procurement		-	-	-		-	-	**£19,189,354**
	Jacket	4 Legged Jacket	-	-	-		-	-	***£7,815,484***
B1.2.2.1.1	Insurance and Certification		-	-	-		£1,872,000	*Insurance and Certification*	£1,872,000
B1.2.2.1.2	*Jacket Steel*		£1,333	Te	2,650	£3,533,333	£212,000		£3,745,333
B1.2.2.1.3	*Piles*		£1,301	Te	1,000	£1,300,667	£78,040	*Logistics/Freight @ 6%*	£1,378,707
B1.2.2.1.4	*Anodes*		£3,685	Te	170	£626,507	£37,590		£664,097
B1.2.2.1.5	*Installation Aids*		£1,127	Te	130	£146,553	£8,793		£155,347
	Topsides		-	-	-		-	-	***£11,373,871***
B1.2.2.2.1	Insurance and Certification		-	-	-		£1,272,000	*Insurance and Certification*	£1,272,000
B1.2.2.2.2	*Primary Steel*		£1,087	Te	230	£249,933	£14,996		£264,929
B1.2.2.2.3	*Secondary Steel*		£900	Te	150	£135,000	£8,100		£143,100
B1.2.2.2.4	*Piping*		£10,733	Te	40	£429,333	£25,760		£455,093
B1.2.2.2.5	*Electrical*		£19,200	Te	20	£384,000	£23,040		£407,040
B1.2.2.2.6	*Instrumentation*		£36,333	Te	20	£726,667	£43,600		£770,267
B1.2.2.2.7	*Miscellaneous*		£8,800	Te	20	£176,000	£10,560		£186,560
B1.2.2.2.8	*Manifolding*		£14,733	Te	50	£736,667	£44,200		£780,867
B1.2.2.2.9	*Control and Communications*	*Sat Comms*	£460,733	Te	5	£2,303,667	£138,220		£2,441,887
B1.2.2.2.10	*General Utilities*	*Drainage, Diesal Storage etc*	£50,000	Te	3	£150,000	£9,000	*Logistics/Freight @ 6%*	£159,000
B1.2.2.2.11	*Vent Stack*	*Low Volume (venting done at beach)*	£6,933	Te	34	£235,733	£14,144		£249,877
B1.2.2.2.12	*Diesel Generators*	*Power Generation*	£52,067	Te	17	£885,133	£53,108		£938,241
B1.2.2.2.13	*Power Distribution*		£36,067	Te	5	£180,333	£10,820		£191,153
B1.2.2.2.14	*Emergency Power*		£34,733	Te	2	£69,467	£4,168		£73,635
B1.2.2.2.15	*Quarters and Helideck*	*50 Te Helideck plus TR*	£23,333	Te	70	£1,633,333	£98,000		£1,731,333
B1.2.2.2.16	*Crane*	*Mechanical Handling*	£19,267	Te	30	£578,000	£34,680		£612,680
B1.2.2.2.17	*Lifeboats*	*Freefall Lifeboats*	£24,400	Te	7	£170,800	£10,248		£181,048
B1.2.2.2.18	*Chemical Injection*	*Chemicals, Pumps, Storage*	£46,600	Te	10	£466,000	£27,960		£493,960
B1.2.2.2.19	*PLR*	*Pig Reciever*	£10,000	Te	2	£20,000	£1,200		£21,200
B1.2.3	Fabrication		-	-			-		**£15,031,648**
	Jacket		-	-			-		***£10,878,745***
B1.2.3.1	*Jacket Steel*		£3,245	m	2,650	£8,598,367	£515,902		£9,114,269
B1.2.3.2	*Piles*		£1,022	m	1,000	£1,022,000	£61,320	*Logistics/Freight @ 6%*	£1,083,320
B1.2.3.3	*Anodes*		£755	Each	170	£128,407	£7,704		£136,111
B1.2.3.4	*Installation Aids*		£3,955		130	£514,193	£30,852		£545,045
	Topsides		-		-		-	-	***£4,152,903***
B1.2.3.2.1	*Primary Steel*		£5,467	Te	230	£1,257,333	£75,440		£1,332,773
B1.2.3.2.2	*Secondary Steel*		£7,200	Te	150	£1,080,000	£64,800		£1,144,800
B1.2.3.2.3	*Equipment*		£1,513	Te	125	£189,167	£11,350		£200,517
B1.2.3.2.4	*Piping*		£14,867	Te	40	£594,667	£35,680	*Logistics/Freight @ 6%*	£630,347
B1.2.3.2.5	*Electrical*		£26,467	Te	20	£529,333	£31,760		£561,093
B1.2.3.2.6	*PLR*	*Pig Reciever*	£25,000	Te	2	£50,000	£3,000		£53,000
B1.2.3.2.7	*Miscellaneous*		£10,867	Te	20	£217,333	£13,040		£230,373
B1.2.4	Construction and Commissioning		-	-	-		-	-	**£22,422,557**
B1.2.4.1	Installation Spread	Jacket Installation	£596,206	Days	28	£16,693,768	£0	-	£16,693,768
B1.2.4.2	Installation Spread	Topsides Installation	£135,533	Days	7	£948,733	£0	-	£948,733
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.3	*Tug Transport - Jacket*	*Infield Operations*	£57,236	Days	16	£915,776	£0	-	£915,776
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.4	*Barge Transport - Jacket*	*Infield Operations*	£8,672	Days	56	£485,632	£0	-	£485,632
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.5	*Tug Transport - Topsides*	*Infield Operations*	£57,236	Days	30	£1,717,080	£0	-	£1,717,080
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.6	*Barge Transport - Topsides*	*Infield Operations*	£8,672	Days	70	£607,040	£0	-	£607,040
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
				Total (Excluding Contingency)					**£76,168,560**
				Pre-FID Contingency (%)				**30%**	**£1,957,500**
				Post-FID Contingency (%)				**30%**	**£20,893,067.88**
				Total (Including Contingency)					**£99,019,127**

PROJECT	Strategic UK Storage Appraisal Project	**WELLS: COST SUMMARY**
TITLE	UNTER CLOSURE 36 Minimum Viable De	
CLIENT	ETI	
REVISION	A01	
DATE	42663	

Pale Blue Dot.

COSTAIN

AXIS WELL TECHNOLOGY

FROM CONCEPT TO COMPLETION

Well Cost Summary (including 30% Contingency)

Well Name	Days	Well Cost (£,000)
Year -2		
Appraisal Well	80.6	26687.5
Year 0		
Slant Injector 1	77.4	26637.5
Slant Injector 2	70.9	24562.5
Slant Injector 3	70.9	24562.5
Slant Injector 4	70.9	24562.5
Monitoring Well - Appraisal Tieback	0.0	0.0
Year 2		
Slant Injector 5		
Year 5		
Local Sidetrack 1	80.6	25300
Year 15		
Local Sidetrack 2		
Year 20		
Slant Injector 6	77.4	26637.5
Slant Injector 7	70.9	24562.5
Slant Injector 8	70.9	24562.5
Slant Injector 9	70.9	24562.5
Workover 1		
Year 22		
Slant Injector 10		
Year 25		
Local Sidetrack 3		
Year 35		
Local Sidetrack 4		
Year 40		
Abandonment Slant Injector 1	23.4	6750
Abandonment Slant Injector 2	16.9	4675
Abandonment Slant Injector 3	16.9	4675
Abandonment Slant Injector 4	16.9	4675
Abandonment Slant Injector 5		
Abandonment Slant Injector 6		
Abandonment Slant Injector 7		
Abandonment Slant Injector 8		
Abandonment Slant Injector 9		
Abandonment Slant Injector 10		
Abandonment Monitoring Well	23.4	6300
TOTAL	838.5	279712.5

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary

Drilling Campaign	Overhead (£MM)
Well 1-4	**2.70**
Well 5	**0.90**
4 Rep. Wells	**2.25**
5th Rep. Well	**0.90**

OPEX Overhead Cost Summary

OPEX Campaign	Overhead (£MM)
Local Sidetrack 1	**0.90**
Local Sidetrack 2	**0.90**
Workover1	**0.45**
Local Sidetrack 3	**0.90**
Local Sidetrack 4	**0.90**

Wells Cost Estimate - Primary Cost Summary

Activity	Drilling Costs: Phase Rig Cost (£,000)	Drilling Costs: Phase Spread Cost (£,000)	Drilling Costs: Contingency (£,000)	Procurement Costs (£,000): Procurement (£,000)	Procurement Costs (£,000): Contingency (£,000)	Total Cost (£,000)
Appraisal Well - CAPEX Breakdown						
Appraisal Well	6450	10625	4012.5	4700	1410	27197.5
Development Wells - CAPEX Breakdown						
Slant Injector 1	5950	9925	4462.5	6400	1920	28657.5
Slant Injector 2	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 3	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 4	5450	9175	4087.5	6400	1920	27032.5
Monitoring Well (Appraisal)	0	0	0	0	0	0
Slant Injector 5						
Slant Injector 6	5950	9925	4462.5	6400	1920	28657.5
Slant Injector 7	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 8	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 9	5450	9175	4087.5	6400	1920	27032.5
Slant Injector 10						
Wells - OPEX Breakdown						
Local Sidetrack 1	6200	10550	4650	3000	900	25300
Local Sidetrack 2						
Workover 1						
Local Sidetrack 3						
Local Sidetrack 4						
Wells - ABEX Breakdown						
Abandonment Slant Injector 1	1530	2970	1350	0	0	5850
Abandonment Slant Injector 2	1105	2145	975	0	0	4225
Abandonment Slant Injector 3	1105	2145	975	0	0	4225
Abandonment Slant Injector 4	1105	2145	975	0	0	4225
Abandonment Slant Injector 5						
Abandonment Slant Injector 6						
Abandonment Slant Injector 7						
Abandonment Slant Injector 8						
Abandonment Slant Injector 9						
Abandonment Slant Injector 10						
Abandonment Monitoring Well	1530	2970	1350	0	0	5850

	CAPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
A1.4.2	Appraisal Well (inc Procurement)	21.8	0.9	Well Management Fees, Insurance, Site Survey, Studies etc	22.7	30%	5.7	**28.4**
A1.3	Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.86**
B1.3.1	Detailed Design PM & E	2.0	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	51.2	0		51.2	30%	15.4	**66.6**
B1.3.4	Construction and Commissioning (Drilling)	119.5	6.75	Well Management Fees, Insurance, Site Survey, Studies etc.	126.3	30%	35.5	**161.7**
	Total	**196.5**	0		**204.5**	**-**	**57.8**	**262.4**

OPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
OPEX	19.8	4.05	Well Management Fees, Insurance, Site Survey, Studies etc.	23.8	30%	5.9	**29.7**

ABEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency %	Contingency £MM	Total Cost (£MM)
ABEX	18.8	5.4	Well Management Fees, Insurance, Site Survey, Studies etc.	24.2	30%	7.2	**31.4**

Level 1 Cost Estimate Summary - Wells

	Total CAPEX (£MM)	262.37
C1.3	Total OPEX (£MM)	29.7
D1.3	Total ABEX (£MM)	31.4
	TOTAL (£MM)	**323.4**